Trinity Public Utilities District
MINUTES OF THE SPECIAL MEETING OF THE BOARD
November 9, 2021

Location:	Trinity Public Utilities District Community Room 26 Ponderosa Lane, Weaverville, California
Board Present:	Alex Cousins, Kelli Gant, Andrew Johnson, Richard Morris, Michael Rourke
Board Absent:	None
Others Present:	Paul Hauser, Jim Underwood, Andy Lethbridge, Mike Garcia, Julie Catanese, and Sarah Sheetz
Others Present via Audio/Video Teleconference:	Scott Lindsay, Kristi Robinson, Guy Colpron, Tony Reed, Scott Murrison, Sam Schmidt, James Aven and Tom Walz

1. **President Rourke called the meeting to order at 2:00 p.m.**

2. **Approval of the Agenda Order**
   Director Morris made a motion to approve the Agenda Order. Director Gant seconded the motion. The motion passed with the following roll call vote:

Alex Cousins	-Aye
Kelli Gant	-Aye
Andrew Johnson	-Absent
Richard Morris	-Aye
Michael Rourke	-Aye

3. **Presentation of Five-Year Strategic Plan by Star Energy Services, BKI Engineers.**
   Mr. Hauser introduced Scott Lindsay of BKI Engineers and Kristi Robinson of Star Energy Services to present the 2022-2026 System Improvement Plan (Plan) (attached and incorporated herein by reference).

   Ms. Robinson provided a presentation on the Plan, detailing the rationale and priority for each project identified. At the end of the presentation the Board inquired for more information about several projects, suggested that Staff rank the projects in order of priority and identify which projects are already included in the Budget.

   Tom Walz thanked Board for investing in the Plan and recommended that the District underground its lines as much as possible. He suggested seeking out grant funding as a revenue source.

4. **Closed Session Report of October 14, 2021 Meeting** Ms. Sheetz provided the Closed Session Report form the October 14, 2021 meeting.

5. **Public Input**
   None

6. **Consent Calendar**

Ms. Sheetz advised that the Meeting Minutes of the October 14, 2021 meeting have been corrected. Item 3. reads "Closed Session Report of the September 9, 2021 Meeting," rather than the August 12, 2021 Meeting. Director Gant requested that Item 6b, Accept Minutes of the Safety Meeting November 2, 2021, be pulled from the Consent Calendar. Director Cousins made a motion to approve the Consent Calendar excepting Item 6b, Director Morris seconded the motion. The Consent Calendar included:

a. Approve Minutes of the Special Meeting on October 14, 2021 and the Regular Meeting on October 14, 2021
~~b. Accept Minutes of the Safety Meeting November 2, 2021~~
c. Validate Bills of October 2021
d. Approve Financial Reports for September 2021
e. Adopt Resolution 21-04 Re-Authorizing Remote Teleconference Meetings

The motion passed with the following roll call vote:

Alex Cousins	-Aye
Kelli Gant	-Aye
Andrew Johnson	-Aye
Richard Morris	-Aye
Michael Rourke	-Aye

7. **Action Items**

a. Items Pulled from Consent Calendar

Item 6b. Accept Minutes of the Safety Meeting November 2, 2021.

Director Gant asked what the Safety Inspections from Cal Fire referenced in the Safety Meeting Minutes were. Mr. Hauser advised that Cal Fire sends a written notice of violations that are noted as a result of inspections.

Director Gant inquired as to why the reclosers at the Mill are on a special setting. Mr. Hauser advised the setting is at the Mill's request.

Director Gant made a motion to Accept the Minutes of the Safety Meeting of November 2, 2021. Director Cousins seconded the motion. The motion passed with the following roll call vote:

Alex Cousins	-Aye
Kelli Gant	-Aye
Andrew Johnson	-Aye
Richard Morris	-Aye
Michael Rourke	-Aye

a. Approve Declaration of Surplus Vehicle and Authorize Disposal

Mr. Hauser reviewed the report with the Board. Following a discussion, Director Cousins made a motion to approve the declaration of surplus vehicle and authorize disposal. Director Gant seconded the motion. The motion passed with the following roll call vote:

Alex Cousins	-Aye
Kelli Gant	-Aye
Andrew Johnson	-Aye
Richard Morris	-Aye
Michael Rourke	-Aye

8. Reports

a. Wildfire Mitigation Plan (WMP) Reporting Metrics Update

Mr. Hauser reviewed the metrics, attached and incorporated herein, with the Board and noted that the District is seeing a decrease in the quantity of poles being reported damaged.

b. General Managers Reports:

- Land Exchange

  Mr. Hauser advised that progress on the land exchange was very slow. Director Cousins suggested that it is time for the District to push for progress. Mr. Hauser stated he would reach out to Congressman Huffman's office.

- Power Outages

  Mr. Hauser reviewed the Outage Summary, attached and incorporated herein, with the Board, highlighted a few significant outages. Director Gant inquired if the increase in tree trimming and removal costs is resulting in fewer outages. Mr. Hauser responded that the magnitude of the problem is huge given the miles of line, number of trees and width of rights of way. He also advised that outages increase when the District sets the reclosers on one-shot for fire safety reasons. There was a brief discussion relative to the removal of trees on private property and legislation introduced by Senator Brian Dahle.

- Balancing Authority of Northern California (BANC)

  Mr. Hauser advised that the solicitation for renewable energy to meet the requirements of Senate Bill 100 has been issued. He reminded the Board that the District meets the requirements with 100% carbon free hydropower.

  It was noted that there is a preference for schedulable energy, such as geothermal or biomass, that is connected to the BANC footprint as any resources that come through the California Independent System Operator are subject to curtailment.

- Right-of-Way (ROW) Project Update

  Mr. Hauser advised that the District is working on being annexed into the Trinity County Local Hazard Mitigation Plan which would meet a requirement to apply for mitigation funding through the Federal Emergency Management Agency.

- Western Area Power Administration (WAPA) Fiber Project Update/Oregon Mountain Communications Building Update
  Mr. Hauser advised that staff from WAPA toured the new Oregon Mountain building last week and began making plans for equipment installation.

- Umpqua Loan
  Mr. Hauser reported that the final approval for the Umpqua Loan will be brought to the Board at the December 9, 2021 meeting.

c. Committee Reports

- Ad-hoc Forestry Committee
  None

- Ad-hoc Mission Statement Committee
  None

- Ad-hoc Rate Committee
  None

- Ad-hoc Public Communications Committee
  None

d. Board Member Reports

Director Cousins distributed information from the Department of Cannabis Control highlighting utility/generator requirements for license renewals beginning in January of 2022. Director Cousins anticipates there may be many requests from local cultivators to document carbon-free energy supply. Mr. Hauser advised he would reach out to other utilities to see what they provide in terms of proof. Director Gant commented on the decommissioning of the Diablo Canyon Power Plant and President Rourke commented on a recent California Municipal Utilities Association article relative to renewables and the potential difficulty of providing affordable and reliable power with the mandates.

9. Discussion Items

- Rate Discussion
  Mr. Hauser provided a draft presentation on the Rate Discussion, attached, and incorporated herein. The Board provided feedback on the presentation for incorporation prior to the first of four public listening sessions.

  A discussion ensued regarding the date, time, and location of the public meetings as well as the process to be followed for the rate hearings. Staff was directed to proceed with scheduling and advertising of the public listening sessions.

10. Communications Received

None

11. Meetings and/or Workshops

a. American Public Power Association Legislative Rally
The Mayflower Hotel, Washington DC
February 28, 2022-March 2, 2022

Mr. Hauser asked that Board Members let Ms. Sheetz know if they are interested in attending the Legislative Rally in Washington DC.

12. Public Input

None

The Board took a brief recess at 4:41 p.m. and entered Closed Session at 4:50 p.m.

13. Closed Session

a. There was no reportable action taken under Government Code §54956.9

b. There was no reportable action under Government Code §54956.9

c. There was no reportable action under Government Code §54957.6

14. Adjournment

There being no further business, President Rourke adjourned the meeting at 5:12 p.m.

Mike Rourke

Michael Rourke, President

ATTEST: Richard L. Morris

Richard Morris, Clerk

3

TRINITY P.U.D.
"Serving Trinity County Since 1982"

TRINITY PUBLIC UTILITY DISTRICT

2022-2026
System Improvement Plan

NOVEMBER 2021

STAR energy services

BKI ENGINEERING SERVICES

2022 - 2026
SYSTEM IMPROVEMENT PLAN

for

Trinity Public Utility District

NOVEMBER 2021

Respectfully Submitted,

STAR ENERGY SERVICES LLC

This report was written by Kristi Robinson, P.E. and Blane Walberg, EIT with STAR Energy Services LLC under the direction of Guy Colpron, P.E. of BKI Engineering Services.

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1 EXECUTIVE SUMMARY

1.1 Introduction

This study was created to outline the proposed distribution and transmission projects for Trinity Public Utility District (TPUD) for the 2022-2026 time period. This study may be used as an interactive planning guide for TPUD for the next five years.

This study will review TPUD's system based on current and forecast conditions, including growth patterns and distribution facilities statuses. Proposed projects will address changes in system growth, aging infrastructure, and power quality issues.

TPUD's historical and projected annual distribution plant investments are shown in Table 1.1. The distribution capital expenditures proposed for the next four years will result in the total utility plant increasing at an average annual rate of approximately 3.6%.

Upon completion of the projects proposed in this document, TPUD's system will continue to be able to provide adequate and reliable service its consumer base.

Table 1.1 Historical and Projected Total Utility Plant Investments

Historical and Projected Total Utility Plant				
	YEAR	TDP Beginning of Year ($)	Distribution Change ($)	Additions divide by TUP
Historical	2012/2013	$ 29,253,000		0.00%
	2013/2014	$ 29,438,000	$ 185,000	0.63%
	2014/2015	$ 29,306,000	$ (132,000)	-0.45%
	2015/2016	$ 29,714,000	$ 408,000	1.37%
	2016/2017	$ 30,378,000	$ 664,000	2.19%
	2017/2018	$ 31,996,000	$ 1,618,000	5.06%
	2018/2019	$ 32,837,000	$ 841,000	2.56%
	2019/2020	$ 35,553,000	$ 2,716,000	7.64%
Estimated	*2020/2021*	*$ 35,728,000*	*$ 850,000*	*2.38%*
System Improvement Estimate	*2021/2022*	*$ 36,578,000*	*$ 1,416,400*	*3.87%*
	2022/2023	*$ 37,994,400*	*$ 1,416,400*	*3.73%*
	2023/2024	*$ 39,410,800*	*$ 1,416,400*	*3.59%*
	2024/2025	*$ 40,827,200*	*$ 1,416,400*	*3.47%*
	2025/2026	*$ 42,243,600*	*$ 1,416,400*	*3.35%*

The goal of this study was to provide a priority list of construction projects to address load growth and aging infrastructure issues TPUD's distribution systems is expected to face in during the 2022-2026 time period. TPUD has experienced growth of large single-phase loads in the recent past, with additional growth expected in the future. With this growth, potential power quality issues may arise, which are also addressed within this study. Additional attention was also given to aging facilities that have a direct impact on the reliability of the utility. A summary of the projects identified with in this study includes:

- Upgrade of Big Bar Substation transformer and high side structure.
- Upgrade of the Grouse Creek Substation structure and transformer replacement.
- Replacement of the Hyampom Substation transformer and regulators.
- Replacement of the Forest Glen Substation transformer.
- Replacement of Mill Street Substation reclosers and controls.
- 8.1 miles of three-phase overhead distribution line replacement to allow for higher capacity loads.
- An additional 28.9 miles of distribution line identified for potential overhead distribution replacement.
- A potential extension of 20 miles of 60 kV transmission.
- 5 miles of three-phase underground replacement due to deteriorating cable.
- Various additions and replacements of distribution line equipment.

1.3 Results of Proposed Projects

Upon completion of the recommended projects, TPUD will reduce system losses, provide additional capacity for current and potential new electric loads, and improve the reliability of service to its consumers. The summary of costs of the proposed projects are listed in Table 1.2.

Table 1.2 Summary of Costs

2022-2026 System Improvement Infrastructure Costs		
High Priority		
Substation & Distribution Line Projects	$	6,046,000
Annual Replacements	$	1,036,000
High Priority Projects & Replacements Total	**$**	**7,082,000**
Low Priority		
Substation & Distribution Line Projects	$	10,360,000
Low Priority Projects Total	**$**	**10,360,000**
High & Low Priority Projects & Replacements	**$**	**17,442,000**
Transmission Projects	$	80,000,000
All Identified Projects & Replacements	**$**	**97,442,000**

2 INTRODUCTION

2.1 Service Area

TPUD is a distribution cooperative that serves the majority of Trinity County in northern California. With headquarters in Weaverville, California, TPUD serves 7,322 members. The majority of the members served are in urban areas. TPUD does serve some rural areas that are mostly residential homes or agricultural businesses.

2.2 Distribution System

TPUD owns, operates, and maintains a 60 kV transmission and multiple different voltage configurations of distribution system. Included in TPUD's system is 600 miles of overhead lines, 150 miles of underground lines, and nine distribution substations. Of the nine substations, five substations are not able have a distribution circuit from a neighboring substation provide contingency at the distribution level. Douglas City, Lewiston, Mill City, and Trinity are able to provide at least partial contingency to neighboring substations. A summary of the substations owned by TPUD is shown in Table 2.1.

Table 2.1 Transmission Supply to TPUD Substations

Transmission Supply to TPUD Substations				
Substation	Primary Voltage	Secondary Voltage	Transmission Provider	Existing Capacity
Big Bar	60 KV	12 kV	PG&E	1 MW
Douglas City	60 KV	12 kV	WAPA	3 MW
Forest Glen	115 kV	12 kV	PG&E	0.5 MW
Grouse Creek	60 kV	12.5 kV	PG&E	0.25 MW
Hayfork	60 kV	12 kV	WAPA	19 MW
Hyampom	60 kV	12 kV	PG&E	2 MW
Lewiston	60 kV	12 kV	WAPA	20 MW
Mill Street	60 kV	12.5 kV	WAPA	20 MW
Trinity	230 kV	60 kV/21 kV	WAPA	60 MW

TPUD is supplied 100% of the power it needs from Western Area Power Administration (WAPA). WAPA is a power marketing administration within the US Department of Energy.

TPUD's substations are served by either 60 kV, 115kV, or 230 kV transmission lines owned and operated by Pacific Gas & Electric (PG&E) and Western Area Power Administration (WAPA). Transmission supply accounted for a significant portion of the overall outage time experienced by TPUD's consumers. In 2019, consumers on substations served by PG&E transmission lines endured 80 hours of transmission outages and in 2020, consumers experienced 36 hours of transmission outages. Consumers served by substations on WAPA transmission lines fared significantly better. In 2019, consumers experienced 19 hours of transmission outages and in 2020, consumers experienced 5 hours of transmission outages. PG&E transmission lines have a large amount of exposure and serves the smaller TPUD substations that are in more rural areas. In recent years, PG&E transmission has been severely affected by wildfires. Additional information regarding power reliability can be found in Section 4.4.

3 BASIS OF STUDY

3.1 Design Criteria

The plans presented in this study are designed to provide a guide for the orderly development of TPUD's distribution system. Planning criteria has been established to evaluate the distribution system at TPUD. The criteria include voltage and line loss levels, conductor and device loading limits, and system reliability. Other considerations include economic analysis, environmental impact, and future power supply changes. Some of the specifics of these criteria are as follows:

- The minimum voltage on the distribution system is not to be less than 118 volts on a 120-volt base under normal peak load conditions. (This assumes the source voltage will be 124 volts.)
- The overall design will be based on a balanced system, allowing for one set of voltage regulators beyond the substation.
- The loading on any conductor is not to exceed 50% of its emergency thermal loading limit.
- Single-phase lines with loading of 50 amps or more will be considered to be rebuilt to three-phase lines.
- Minimum main three-phase feeder size will be 4/0 conductor when reconductoring or building new feeder line.
- Minimum size conductor considered for use will be either 1/0 ACSR or 1/0 URD.
- System improvements will be considered in areas where excessive member outages and cable failures occur.
- Deteriorated plant replacement, addressing line that is not specifically addressed by excessive voltage drop, road projects, or loading, will be a focus to improve reliability. Line replaced under this criterion seeks to eliminate undersized wire, reduce voltage drop, decrease losses, improve system reliability, and improve safety.
- Unfinished work-in-progress projects are assumed to be completed and part of the existing system model.

3.2 References

In preparation of this five-year plan, the following documents were used as references:

- Trinity Public Utilities District System Improvement Plan – prepared by BKI Engineering, 2016
- 2012-2021 Fiscal Year Budgets – prepared by TPUD

3.3 Equipment Loading

TPUD designs the distribution system so the minimum voltage is not to exceed 118 volts on a 120-volt base under normal peak load conditions, assuming a starting voltage of 126 volts. Table 3.1 and Table 3.2 explains the loading levels used by TPUD in planning changes to the distribution system.

Table 3.1 Equipment Loading Actions

Equipment Loading Actions		
Device	Loading Level Exceeds	Action
Voltage Regulator	75%	Upgrade Device (or further analyze)
Substation Transformer	100%	Upgrade Device (or further analyze)
Line Fuses	75%	Upgrade Device (or further analyze)
	100%	Replace
Reclosers	75%	Upgrade Device (or further analyze)
	100%	Replace
Sectionalizers	75%	Upgrade Device (or further analyze)
	100%	Replace
Single-Phase Conductor	50 Amps	Consider Upgrading to Three-Phase
Primary Conductor	50% of emergency thermal loading limits	Upgrade Conductor Size or Change System Configuration

OVERHEAD CONDUCTOR THERMAL LIMITS 12.5 kV Distribution System								
	Winter				Summer			
	Normal Demand		Emergency Demand		Normal Demand		Emergency Demand	
Overhead Conductor	Current (amps)	Power (kW)	Current (amps)	Power (kW)	Current (amps)	Power (kW)	Current (amps)	Power (kW)
#4 ACSR (#6 Cu.)	160	3,100	200	3,900	125	2,400	155	3,000
#2 ACSR (#4 Cu.)	215	4,200	270	5,300	165	3,200	210	4,100
1/0 ACSR (#2 Cu.)	280	5,500	350	6,800	215	4,200	270	5,300
T2-2 ACSR	320	6,200	400	7,800	245	4,800	305	5,900
3/0 ACSR	375	7,300	475	9,300	290	5,700	365	7,100
4/0 ACSR	430	8,400	535	10,400	330	6,400	410	8,000
T2-1/0 ACSR	430	8,400	535	10,400	330	6,400	410	8,000
336.4 MCM ACSR	665	13,000	830	16,200	510	9,900	640	12,500
397.5 MCM ACSR	740	14,400	925	18,000	570	11,100	710	13,800
477 MCM ACSR	825	16,000	1,025	19,900	630	12,200	790	15,400

Assumed conditions are as follows:

2) *Wind velocity: 2 feet/second (1.36 mph)*
3) *Emissivity at 0.5*
4) *Normal and Emergency limits are based on maximum allowable conductor temperatures of 75° C and 100° C, respectively*
5) *Assumed balanced three-phase load at 90% power factor*
6) *T2-2 and T2-1/0 assumed characteristics thermally of 2/0 and 4/0 ACSR, respectfully*

4 LOAD ANALYSIS

4.1 Purchases

In fiscal year 2020/2021, TPUD purchased 141,300 MWh from WAPA. TPUD is currently forecasting that energy purchases will stay flat over the next five years for budgeting purposes, as shown in Table 4.1. However, for this study, moderate and high growth scenarios are assumed.

Table 4.1 Energy Purchases by Supplier

	Energy Purchases Actual & Forecasted (MWh)									
	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	2024/2025	2025/2026
WAPA	120,400	120,600	118,600	126,900	141,300	141,260	141,260	141,260	141,260	141,260
Total	120,400	120,600	118,600	126,900	141,300	141,260	141,260	141,260	141,260	141,260

A summary of the energy loss for the past five years is shown below. Energy losses are defined by subtracting the number of kilowatt-hours sold from the number of kilowatt-hours bought. As shown in Table 4.2, the five-year average system energy losses remained in the 9% range. Nationally, the average system losses for electrical utilities are 7%. TPUD's system losses have been estimated to cost the utility approximately $317,000 in 2020. As wholesale power costs continue to rise, it is expected that these same losses will cost the utility more in the future.

One way to decrease electrical losses is to replace older substation and distribution transformers with more efficient models. Another method to decrease electrical losses is to use larger conductor sizes to reduce the thermal losses, (Example: using 1/0 or 4/0 ACSR instead of #2 ACSR on main three-phase lines.) A reduction of 1% in losses results in annual saving of $45,000.

Table 4.2 Historical System Losses

Historical System Losses					
Year	Energy Purchased (MWh)	Energy Sold (MWh)	Own Use (MWh)	Losses (MWh)	Losses (%)
2016/2017	120,423	101,035	-	10,821	8.99%
2017/2018	120,577	108,677	-	11,746	9.74%
2018/2019	118,556	109,676	-	10,901	9.19%
2019/2020	126,855	107,666	-	10,890	8.58%
2020/2021	141,260	114,245	-	12,610	8.93%
				Five Year Average	9.09%

4.3 Growth Patterns

4.3.1 Energy Sales

In the past ten years, there has been an average of a 0.16%-consumer increase per year; in the past five years, the average consumer increase per year was 0.12%. During those time periods, energy sales have increased on average 3.2% per year over ten years and increased on average 4.58% per year over five years. A summary of the member and load data for the time period of 2009-2021 is presented in Table 4.4.

In 2020, the total energy sales were 141,260 MWh. The breakdown of consumers and energy sales by consumer classification for TPUD is shown in Figures 1 and 2. A further break down can be found in Table 4.3.

Figure 1 2020 Energy Usage by Classification

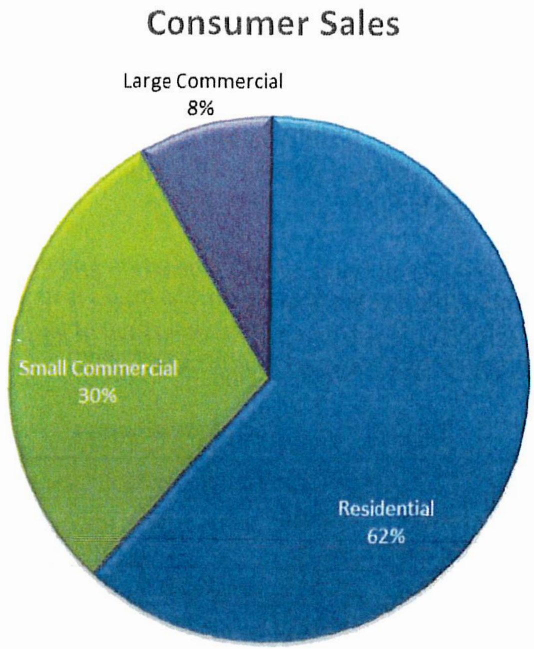
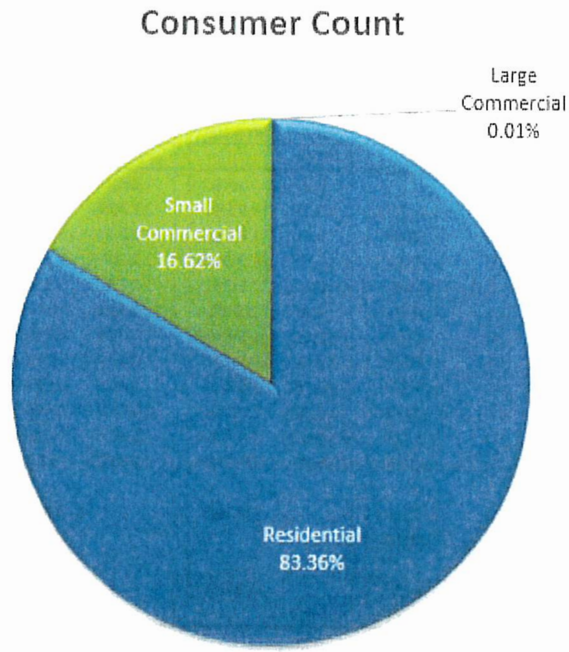


Figure 2 2020 Consumer Classification



Residential and small commercial average monthly energy usage has stayed consistent over the past five years from the average high of 1,173 kWh in 2019/2020 to the low of 1,200 kWh in 2016/2017. It is not expected that the average monthly energy usage for residential and small commercial services will increase significantly in the next five years.

Table 4.3 Monthly Energy Usage Residential and Small Commercial Classes

Monthly Energy Usage Residential and Small Commercial Classes				
	2016-2017	2017-2018	2018-2019	2019-2020
Residential	912	929	911	910
Small Commercial	2,669	2,332	2,266	2,330
Average Energy Use	1,200	1,159	1,133	1,173

Table 4.4 Historical Load Data

Historical Load Data												
	Usage Growth				Losses		System Demand			Meter Growth	
Fiscal Year	Energy Purchased (MWh)	Energy Sold (MWh)	Own Use (MWh)	Increase in Energy Sold (%)	Energy Loss (MWh)	Loss Percent of Purchase (%)	System Peak Demand (kW)	Increase in Peak Demand (%)	Annual Load Factor (%)	Average Consumer Count	Increase in Consumer Count (%)
2009/2010	94,199	89,023	0	-	5,176	5.49%	18,748	-	57.36	7,119	-
2010/2011	102,918	92,717	0	4.15%	10,201	9.91%	20,483	9.25%	57.36	7,204	1.2%
2011/2012	107,747	98,246	0	5.96%	9,501	8.82%	22,244	8.60%	55.30	7,231	0.4%
2012/2013	108,184	98,047	0	-0.20%	10,137	9.37%	22,882	2.87%	53.97	7,238	0.1%
2013/2014	108,307	98,182	0	0.14%	10,125	9.35%	24,175	5.65%	51.14	7,224	-0.2%
2014/2015	105,417	94,241	0	-4.01%	11,176	10.60%	20,694	-14.40%	58.15	7,274	0.7%
2015/2016	111,856	101,035	0	7.21%	10,821	9.67%	22,066	6.63%	57.87	7,320	0.6%
2016/2017	120,423	108,677	0	7.56%	11,746	9.75%	24,274	10.01%	56.63	7,324	0.1%
2017/2018	120,577	109,676	0	0.92%	10,901	9.04%	24,286	0.05%	56.68	7,246	-1.1%
2018/2019	118,556	107,666	0	-1.83%	10,890	9.19%	24,176	-0.45%	55.98	7,246	0.0%
2019/2020	126,855	114,245	0	6.11%	12,610	9.94%	25,037	3.56%	57.84	7,261	0.2%
2020/2021	141,260	125,829	0	10.14%	15,431	10.92%	28,322	13.12%	56.94	7,322	0.8%
5 Year Average				4.58%		9.77%		5.26%	56.81%		0.01%
Growth over 5 Years				29.98%				16.68%	0.54%		-0.03%
10 year Average				3.20%		9.67%		3.56%	56.05%		0.16%
Growth over 10 Years				43.78%				27.32%	2.97%		1.26%

- Data compiled from TPUD's financial reports
- Averages computed by taking average of past 5 or 10 years

4.3.2 Peak Demand

The peak system demand to date was 28,322 kW, which occurred in fiscal year 2020/2021. Historically, the system peak has occurred in the winter months. As shown in Table 4.4, over the past ten years the system peak on average has increased by 27.32%.

4.3.3 Load Factor

During the past five years, the average annual load factor has been 56.81%, which is consistent with the average load factor of 56.05% for the past ten years. It is expected that the load factor will remain at 56% for the next five years.

4.4 System Outages and Reliability

Power reliability varies dramatically for TPUD's consumers depending on what substation they are served from. This is mostly due to weather events that may happen, affecting transmission and the distribution system. In 2019 and 2020, the 341 electric services served from PG&E fed substations, (Big Bar, Forest Glen, Grouse Creek, and Hyampom), experienced an average outage duration of 124 hours and 69 hours, respectively. In contrast, the 6,673 electric services served from WAPA fed substations, (Douglas City, Hayfork, Lewiston and Mill Street), experienced an average outage duration of 24 hours and 27 hours in 2019 and 2020, respectively.

The substations served by PG&E transmission are very rural; therefore, are more likely affected by the long transmission exposure. In addition, weather caused outages on the distribution system contribute to longer restoration durations due to the remote locations of the substations and their electric services.

Methods to increase reliability include adding distribution tie lines between separate circuits. Reliability tracking should also minimize the number of "unknown" outages to better address reoccurring outage issues.

Table 4.5 SAIDI Indices by Substation

Substation	Consumers	SAIDI		
		2019	2020	Two-year Average
PG&E	**341**	**124**	**69**	**96**
Big Bar	125	131	97	114
Forest Glen	26	64	32	48
Grouse Creek	6	14	24	19
Hyampom	184	131	57	94
WAPA	**6673**	**24**	**27**	**25**
Douglas City	725	26	14	20
Hayfork	1369	27	52	40
Lewiston	1631	10	11	10
Mill Street	2948	29	28	28
Total	7014	29	29	29

SAIDI: System Average Interruption Duration Index. The total sustained interruption duration for the average consumer during a calendar year.

Figure 3 2019 PG&E Substation Outage Causes

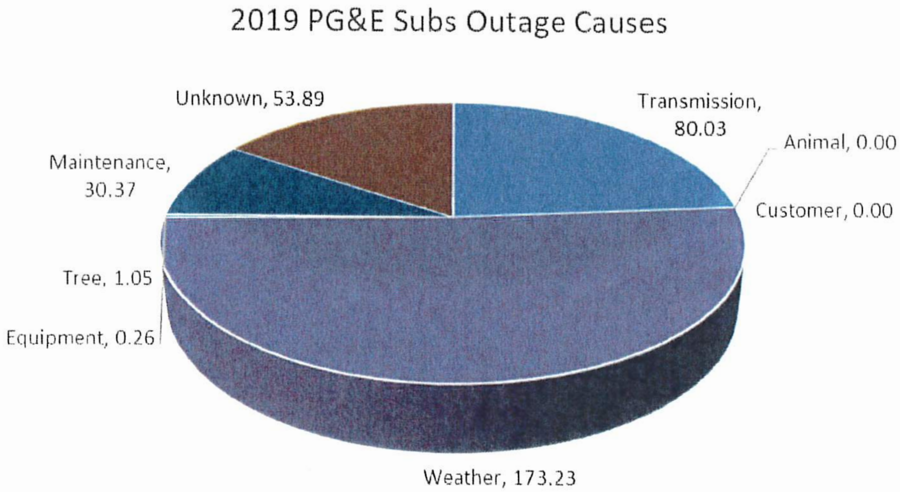
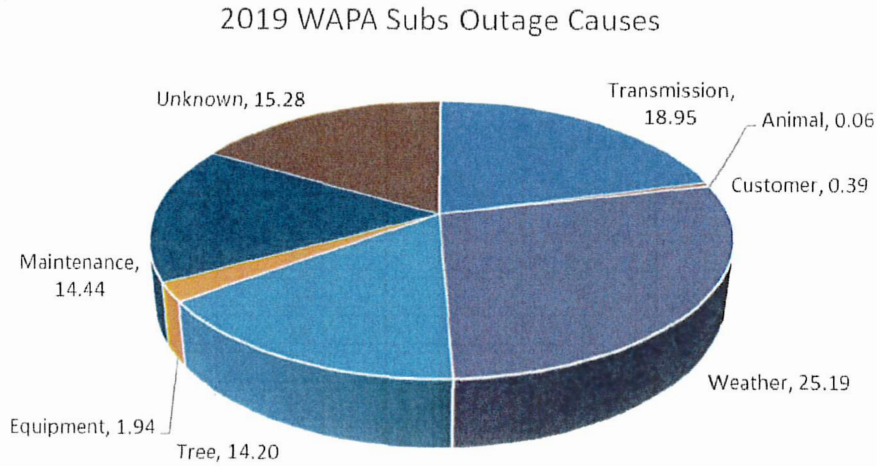


Figure 4 2019 WAPA Substation Outage Causes



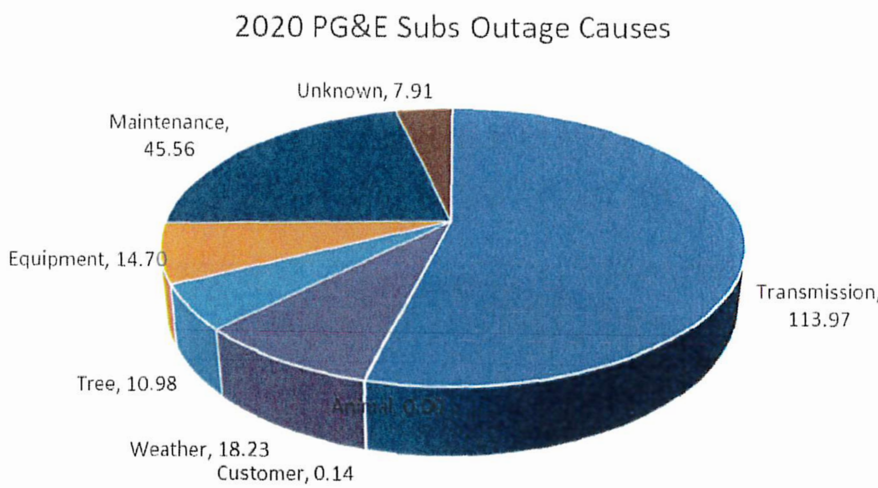
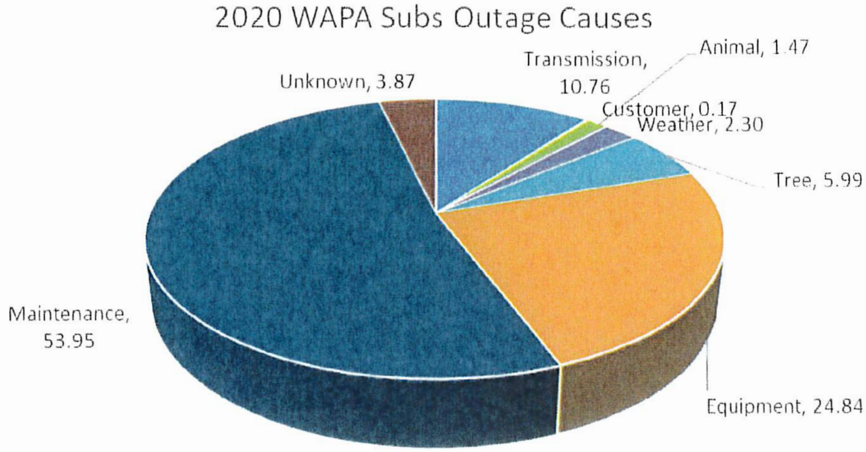


Figure 6 2020 WAPA Substation Outage Causes



TPUD deployed Aclara TWAC PLC AMI in 2019. The two-way AMI meters will allow for more advanced metering capabilities, such as automatic outage notification. The AMI deployment was completed in the 2020/2021 fiscal year. TPUD expects only to deploy new metering to approximately 100 services per year during the next five years.

5 REQUIRED CONSTRUCTION ITEMS

5.1 New and Upgraded Services

It is expected TPUD will provide service to approximately 20 new services per year for a total of 100 new services during the 2022-2026 time period. In addition, TPUD is expected to upgrade approximately 50 services each year. The expense for the new services and service upgrades will be offset by TPUD's contribution in aid policy.

5.2 Substation Transformers

In the following sections, there will be discussion to replace the existing substation transformers at various substation locations. Currently, TPUD prefers to use single-phase substation transformers. Unfortunately, there are very few transformer manufacturers that will build 60 kV and above single-phase transformers that transform voltage to 12.5 kV. The industry standard for substation transformers are now three-phase transformers with the smallest size available typically a 5 MVA. Many transformer manufacturers will either refuse to build transformers smaller than a three-phase 5 MVA or will charge more for smaller single-phase substation transformers.

While a few transformer manufacturers, such as Virginia Transformers, will still build a 60 kV/12.5 KV single-phase transformer, TPUD may choose to request the single-phase substation transformers rebuilt with various vendors, such as Jordan Transformers, T&R Electric or Solomon Corporation. The cost to purchase a refurbished unit will be significantly less than purchasing new. Do note, all estimated costs listed for substation transformers are for new three-phase units.

5.3 Big Bar Substation

The distribution system served by the Big Bar Substation does not require any specific line replacement or upgrade to serve the existing load. Big Bar Substation is not expected to have much load growth in the next five years. While the Big Bar Substation does experience a significant duration of power outages, the outages are mainly due to transmission outages from PG&E.

The Big Bar Substation is currently comprised of three single-phase substation transformers sized at 250 kVA, 333 kVA, and 333kVA with three single-phase regulators sized at 200 amps each. The transformers in the Big Bar Substation are 1960 vintage and should be either rebuilt or exchanged for a new three-phase 5 MVA transformer. If the single-phase transformers are changed to a new three-phase transformer, the foundation for the transformer will most likely need to be expanded. The estimated cost to expand the substation foundation and change the substation transformers to a three-phase 5 MVA transformer is $350,000. This project is identified as Project BB-1.

In addition to Project BB-1, Project BB-2 is the replacement of the high side structure of the Big Bar Substation. The high side structure of the Big Bar Substation is currently a wooden structure. The wood structure is subjected to rot, flashover, and potential wildfires. The cost to replace the high side substation structure with steel construction is estimated at $200,000.

5.4 Douglas City Substation

The Douglas City Substation currently serves approximately 1,630 electric services. The substation area is expected to grow approximately 2% annually for the next five years. Even with the planned growth, there are no distribution line projects planned for this substation area.

The Douglas City Substation is comprised of three single-phase 1 MW transformers and three single-phase 200-amp regulators. The substation equipment is approximately 15-20 years in age and in good condition. The Douglas City Substation can provide contingency electric supply to Lewiston and Mill Street Substations.

When Douglas City Substation provides contingency service to Lewiston Substation Circuit 1101, low voltage can occur and potentially a thermal overload. A lower priority project would be to upgrade Douglas City Substation Circuit 1101 for 3.5 miles from three-phase #2 ACSR to three-phase 4/0 ACSR. This project, Project DC-1, is estimated to cost $1,790,000.

5.5 Forest Glen Substation

The Forest Glen Substation serves under 30 services, with most of them idle due to wildfires in the recent years. There is no expectation that electric load will grow in the next five years.

The transformer in the Forest Glen Substation is approaching the end of its useful life at 53 years old. However, until a clearer picture of whether electric load will return, the recommendation is to not replace the substation transformer immediately. If the load was to return during the 2022-2026 time period, the estimated cost to replace the transformer is $300,000. TPUD may have a suitable three-phase pad mount transformer already stored in inventory. This project is known as Project FG-1.

5.6 Grouse Creek Substation

The Grouse Creek Substation serves a handful of permanent services with a single-phase 250 kVA transformer. There is no expectation that electric load will grow in the next five years. There are no distribution line projects planned for this substation area.

The single-phase transformer in the Grouse Creek Substation is approaching the end of its useful life at 56 years old. By the end of the five-year period, the transformer will be over 60 years old. Oil testing has not shown signs of deterioration; however, plans should be made to replace this transformer unit. Project GC-1, the replacement of a 60 KV/12.5 KV 333 kVA transformer, is expected to cost $120,000.

In addition, the substation is currently of wooden frame construction. As wood structures are subjected to rot, flashover, and potential wildfires, it is recommended to rebuild the substation in steel construction. The rebuilding of the Grouse Creek Substation, Project GC-2, is expected to cost $200,000.

5.7 Hayfork Substation

The Hayfork Substation is a dual transformer substation, with both a 7 MVA and 12 MVA three-phase substation transformer inside. There are three circuits that serve the electric load, with Circuit 1201 being the heaviest loaded at 2.2 MW. The Hayfork Substation serves approximately 20% of TPUD's consumers.

Currently, low voltages issues exist on Circuit 1201, which will only get worse as the Hayfork Substation continues to see 2% annual load growth. With the expected growth, the existing conductor will be thermally overloaded by the end of 2026.

Project HF-1 is the rebuilding of Circuit 1201 from #2 ACSR to 4/0 ACSR from the Hayfork Substation for approximately 1.2 miles. This project is estimated to cost $600,000.

Circuit 1202 and 1203 are also expected to see 2% annual growth. These circuits are currently lighter loaded than Circuit 1201. While these circuits should not see thermal or power quality issues during the next five years, it is advisable to consider replacing the first mile of Circuit 1202 out of the substation with 397 AAC. This project, Project HF-2, is estimated to cost $1,480,000.

The option does exist to extend 14 miles of three-phase 4/0 AL cable from Hayfork Substation Circuit 1203 to the Forest Glen Substation area. This project, Project HF-3, is expected to cost $3,500,000. The three-phase extension also allows for the possibility to serve the Trinity Pines area and other electrical loads.

5.8 Hyampom Substation

The Hyampom Substation is comprised of three single-phase 667 kVA transformers. Oil testing indicated significant degrading to the transformers leading to the increase probability of the transformers malfunctioning. As the Hyampom Substation cannot be back fed by a neighboring substation, an outage due to the Hyampom Substation transformers failing will lead to a prolonged outage for the 185 electric services on this substation.

The estimated cost to replace the existing transformers with a 5 MVA three-phase transformer is $450,000; including foundation modifications and new 219-amp regulators. This is known as Project HY-1.

Minor growth of 1% annual is expected to occur on the Hyampom Substation. With the projected growth, there are no distribution line projects planned for this substation area.

The electric services on the Hyampom Substation area experienced an average of 131 hours of outage duration in 2019 and an average of 57 outage hours in 2020. The leading cause of the outages is due to transmission outages from PG&E. An optional transmission project to increase the reliability to the Hyampom Substation area, Project HY-2, is to extend 60 kV line approximately 20 miles from Hayfork Substation. The cost of the transmission line extension is estimated at $4 million per mile, due to the terrain and right-of-way acquisition.

5.9 Lewiston Substation

The Lewiston Substation is a double-ended substation with each end comprising of three 3,333 kVA single-phase transformers. The Lewiston Substation can provide contingency power supply to the Douglas City Substation. Lewiston Substation currently serves approximately 1,630 electric services.

During a contingency situation, when Lewiston Substation is providing electric service to Douglas City Substation load, there will be significant voltage drop issues that cannot all be addressed with additional distribution regulation. It is recommended that it be the long-term goal to extend three-phase 4/0 AL or 4/0 ACSR to Douglas City Circuit 1101 at Switch 3143. This project, Project LE-1, is approximately 8.5 miles of three-phase #2 ACSR that would need to be rebuilt to 397 AAC at an estimated cost of $3,590,000.

5.10 Mill Street Substation

The Mill Street Substation is similar in construction to the Lewiston Substation, with three 3,333 kVA transformers setup in two separated substation bays. Each substation bay has three 668-amp single-phase regulators. TPUD's industrial consumer is located on Circuit 1102 and this circuit is expected to see 2% annual growth over the next five years.

Multiple different distribution line projects have been identified for this substation area. The projects are due to load growth in the area.

Recommended on the Mill Street Substation area is the rebuilding of three-phase #2 ACSR to three-phase 4/0 on Circuit 1102 from Fuse 1102 to Pole 10929 for approximately 3.5 miles. This project, Project MS-1, is needed to address low voltage and potential thermal overloading issues. The cost estimate of this project is $1,750,000.

It is also recommended as a project to rebuild from three-phase #2 ACSR to three-phase 397 AAC on Circuit 1103 from the substation for approximately 1 mile. This project, Project MS-2, is needed to address low voltage and thermal overloading issues. The cost estimate of this project is $511,000.

Another identified project, Project MS-3, is the rebuilding of three-phase #2 ACSR to three-phase 397 AAC on Circuit 1106 from the substation for approximately 1.4 miles. In addition, two sets of distribution line regulators are recommended to address low voltage issues. The cost estimate of this project is $715,000.

Lastly, it is highly recommended to rebuild three-phase #2 ACSR to three-phase 4/0 ACSR on Circuit 1107 from the substation for approximately 1 mile. Circuit 1107 has various segments of the distribution system ranging between #2 ACSR to 4/0 ACSR for the first three miles from the substation. This project, Project MS-4, is needed to address low voltage issues. The cost estimate of this project is $500,000.

In addition to the distribution projects identified in this section, it is also recommended that the recloser controls located in the Mill Street Substation be upgraded from the Cooper Form C to Cooper Form 7 controllers. With this change, it is also recommended that any oil filled reclosers within the substation be changed to vacuum reclosers. Each circuit recloser bank replacement with updated controls is expected to cost $87,500. In this project, Project MS-5, it is assumed four (4) banks of reclosers are to be changed out for a total estimated cost of $350,000.

5.11 Trinity Substation

The Trinity Substation is owned and operated by WAPA. The substation is comprised of two 30 MW three-phase three-winding transformers. The 230kV/60 kV windings of the Trinity Substation leave the Trinity Substation as a transmission circuit to the Lewiston Substation, Douglas City Substation, and Mill Street Substation. The other transformer winding is 21 KV and is transformed further outside the substation at a 21kV/12 kV 2.5 MW pad mount transformer. This distribution circuit then continues north around Trinity Lake towards the Trinity Center Airport. In addition, the 21 kV circuit from the Trinity Substation extends north approximately 11 miles to where is there is another 21kV/12 kV 2.5 MW pad mount transformer that can be tied into the north Trinity circuit for redundancy. No distribution or transmission projects have been identified for the Trinity Substation area.

5.12 Miscellaneous Replacements & Additions

5.12.1 Underground Cable Replacement

TPUD should plan to replace one mile of three-phase underground cable on an annual basis due to the eroding of the concentric neutral from cable installed in the 1970-1980s. If the conductor to be replaced is part of the circuit backbone, it is strongly encouraged the cable installed be upgraded to 4/0 AL. The estimated cost annually is $320,000. Environmental planning costs are not included in this estimate.

5.12.2 Pole Replacements

With the existing pole testing process, TPUD should expect to change out approximately 225 poles per year. Annually, this would be a cost of approximately $450,000 per year.

5.12.3 Metering Replacements

TPUD finished the deployment of Aclara TWAC PLC AMI system in the fiscal year 2020/2021. While all meters have been changed out, TPUD will still expect to add or change out approximately 100 meters annually. The cost of the metering on an annual basis is estimated at $20,000 per year.

5.12.4 Transformer Installations

While there still are a few new electric services occurring annually, TPUD's load growth is mainly due to existing services upgrading in size. Between the new services and upgrading of existing services, along with normal equipment replacement, TPUD will need to budget for approximately $126,000 in distribution transformer purchases and installation annually.

5.12.5 Line Regulators

TPUD should plan to add three (3) line regulators annually to assist with continual growth on the distribution system. The cost of the line regulators and installation is estimated at $60,000 annually.

5.12.6 Line Reclosers

TPUD should plan to add one (1) three-phase bank of line reclosers annually to continue to sectionalize the distribution system to help with reliability improvement. The estimated cost of the three-phase line reclosers bank and installation is estimated at $60,000 annually.

6 COST BY CODES

The following section includes detailed information on the projects planned for the 2022-2026 time period.

Table 6.1 Substation and Transmission Changes

SUBSTATION AND TRANSMISSION CHANGES				
Project Code	Priority	Substation	Project Description	Estimated Cost
BB-1	High	Big Bar	Replacement of 250/333/333 kVA transformers with 5 MVA transformer	$ 350,000
BB-2	High	Big Bar	Replacement of wooden substation structure	$ 200,000
FG-1	High	Forest Glen	Replacement of 560 kVA three-phase transformer	$ 300,000
GC-1	High	Grouse Creek	Replacement of 60 kV/12.5 kV 250 kVA three-phase transformer	$ 120,000
GC-2	High	Grouse Creek	Replacement of wooden substation structure	$ 200,000
HY-1	High	Hyampom	Replacement of 677/677/677 kVa transformers and 219 A regulators	$ 450,000
MS-5	High	Mill Street	Replacement of 4 oil-filled reclosers banks with vaccum recloser with Form 7 controls	$ 350,000
HY-2	Low	Hyampom	Extension of 60 kV Transmission from Hayfork Substation to Hyampom Substation	$ 80,000,000
			Total	$ 81,970,000
			High	$ 1,970,000
			Low	$ 80,000,000
			Total	$ 81,970,000

Distribution Line Changes

DISTRIBUTION LINE CHANGES										
			Existing Line			New Line				
Project Code	Priority	Sub/Ckt	Phase	OH UG	Conductor	OH UG	Phase(s)	Conductor	Miles	Estimated Cost
HF-1	High	Hayfork 1201	3	OH	#2 ACSR	OH	3	4/0 ACSR	1.20	$ 600,000
LE-1	Low	Lewiston 1101	3	OH	#2 ACSR	OH	3	397 AAC	8.50	$ 3,590,000
DC-1	Low	Douglas City 1101	3	OH	#2 ACSR	OH	3	397 AAC	3.50	$ 1,790,000
HF-3	Low	Hayfork 1203	-	-	-	OH	3	4/0 ACSR	14.00	$ 3,500,000
HF-2	Low	Hayfork 1202	3	OH	#2 ACSR	OH	3	397 AAC	2.90	$ 1,480,000
MS-1	High	Mill Street 1102	3	OH	#2 ACSR	OH	3	4/0 ACSR	3.50	$ 1,750,000
MS-2	High	Mill Street 1103	3	OH	#2 ACSR	OH	3	397 AAC	1.00	$ 511,000
MS-3	High	Mill Street 1106	3	OH	#2 ACSR	OH	3	397 AAC	1.40	$ 715,000
MS-4	High	Mill Street 1107	3	OH	#2 ACSR	OH	3	4/0 ACSR	1.00	$ 500,000
								Total	37.0	$ 14,436,000
								High	8.1	$ 4,076,000
								Low	28.9	$ 10,360,000
								Total	37.0	$ 14,436,000

Table 6.3 Miscellaneous Line Additions and Replacements

MISCELLANEOUS LINE ADDITIONS AND REPLACEMENTS				
Description	Duration	Quanity	Annual Cost	
Underground Cable	Annually	1 mile	$	320,000
Poles	Annually	225	$	450,000
Metering	Annually	100	$	20,000
Transformers	Annually	100	$	126,000
Regulators	Annually	3 (1ϕ)	$	60,000
Reclosers	Annually	1 (3ϕ)	$	60,000
		Total	**$**	**1,036,000**

Table 6.4 Summary of Costs Breakdown

2022-2026 System Improvement Infrastructure Costs		
High Priority		
Substation Projects	$	1,970,000
Distribution Line Projects	$	4,076,000
Annual Replacements	$	1,036,000
High Priority Projects & Replacements Total	**$**	**7,082,000**
Low Priority		
Substation Projects	$	-
Distribution Line Projects	$	10,360,000
Low Priority Projects Total	**$**	**10,360,000**
High & Low Priority Projects & Replacements	**$**	**17,442,000**
Transmission Projects	$	80,000,000
All Identified Projects & Replacements	**$**	**97,442,000**

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Wildfire Mitigation Efforts
2021 - Report to Date (11/1/2021)

Annual Pole Inspection Data

Patrol Inspection - all poles 1x every 2 years (target is 6,000/year)
Intrusive Inspection - due at 15 years, then 20 year interval if passes (target 1,000/year)

Date	1/1/2021-11/1/2021
Inspections Completed	4,075
Intrusives Completed	915
Poles Reported Damaged	188
Work Orders Completed	162

Monument+ River Fire			
Silvertop Tree Service Watkins Tree Service			
Hazard trees adjacent to powerlines in Big Bar and Helena			
	August (pre-fire)	September	October
Trims	249	798	620
Removal Class 1	133	789	316
Removal Class 2	40	147	167
Brush Cut	0	23	3
T&M Hours removals	42	206	189

ROW Brushing and Chipping		189 Crew Hours
TCRCD	Silvertop Tree Service	The Watershed Center
Dutch creek	1.5 miles of ROW DC 60kv ROW	Dutch creek Rd

8b

OUTAGE SUMMARY
OCTOBER 14, 2021 - NOVEMBER 5, 2021

Time Off	Time On	Sub	Map Location	Feeder	# Out	Duration	Cause Desc	Equip Desc
10/16/2021 8:52	10/16/2021 10:15	Mill Street	Martin Road/Pioneer	W03	76	1:22	Animal/Bird	Fuse
10/17/2021 16:05	10/17/2021 17:45	Mill Street	Junction City/Oregon Mountain	W02	503	1:40	Unknown Cause	Circuit breaker
10/18/2021 8:20	10/18/2021 11:04	Hayfork	Hayfork	HF3	1020	2:44	Tree	OH Conductor
10/19/2021 20:24	10/20/2021 2:39	WAPA Trinity	North County	T21	798	6:15	Tree	OH Conductor
10/20/2021 7:46	10/20/2021 8:24	Mill Street	Little Browns Creek	W01	44	0:38	Tree	OH Conductor
10/21/2021 14:41	10/21/2021 23:30	Mill Street	Coopers Bar Estates	W02	91	8:49	Material or Equipment Fault/Failure	Power Transformer
10/24/2021 10:54	10/24/2021 14:14	Douglas City	Readings Creek	DC1	217	3:20	Rain	Pole
10/26/2021 7:35	10/26/2021 8:15	Mill Street	Weaverville/Airport/Rush Creek Estates	W06	982	0:40	Tree	OH Conductor
10/26/2021 10:22	10/26/2021 12:26	Mill Street	Junction City/Sky Ranch	W02	502	2:03	Federal Tree	OH Conductor
10/29/2021 8:30	10/29/2021 13:47	Douglas City	Deerlick/Reading Creek/B Bar K	DC1	217	5:17	Maintenance	OH Conductor
10/30/2021 22:53	10/31/2021 3:00	Lewiston	Lewiston Substation	L01/L02	1190	4:07	Tree	OH Connector, Clamp or Splice
10/31/2021 23:15	11/1/2021 5:30	Lewiston	Lewiston Substation	L01/L02	1190	6:15	Station Transformer	Power Transformer
11/1/2021 2:09	11/1/2021 6:02	Lewiston	1st Avenue - Apartment Complex	L01	15	3:53	Material or Equipment Fault/Failure	Power Transformer
11/2/2021 11:19	11/2/2021 12:48	Hayfork	Wingert Road	HF2	10	1:29	Unknown Cause	Fuse
11/3/2021 23:32	11/4/2021 3:18	Mill Street	Upper Road/Junction City	W02	14	3:46	Tree	Fuse

Renewals

8d

(2) The license number and expiration date.

(3) The licensee's address of record and licensed premises address.

(4) Documentation demonstrating the licensee's gross revenue for the current licensed period, such as a copy of the licensee's state tax return filed with the California Department of Tax and Fee Administration. This subsection does not apply to the renewal of cultivation licenses.

(5) Documentation of any change to any item listed in the original application under section 15002 of this division that has not been reported to the Department through another process pursuant to the Act or this division.

(6) An attestation that all information provided to the Department in the license renewal form and the original application under section 15002 of this division or subsequent notification under sections 15023 and 15024 of this division is accurate and current.

(7) If applicable, a limited waiver of sovereign immunity pursuant to section 15009 of this division.

(8) For a licensee with more than one employee, the licensee shall attest that it employs, or will employ within one year of renewing the license, one supervisor and one employee who has successfully completed a Cal-OSHA 30-hour general industry outreach course offered by a training provider that is authorized by an OSHA Training Institute Education Center to provide the course.

(e) A cultivation licensee may request a license designation change from an A-License to an M-License or an M-License to an A-License during the annual license renewal timeframes outlined in subsections (a)-(c) of this section for the annual license for which the license designation change is being requested. License designation changes will be considered only if the annual licensed cultivation premises for which the change is being requested contains only one A-License or only one M-License designation pursuant to section 15002(c)(3).

(f) Beginning January 1, 2022, an application for renewal of a license to engage in commercial cannabis cultivation shall include the following records, for each power source indicated on the application for licensure for the previous annual licensed period:

(1) Total electricity supplied by local utility provider, name of local utility provider, and greenhouse gas emission intensity per kilowatt hour reported by the utility provider under section 398.4(c) of the Public Utilities Code for the most recent calendar year available at time of submission;

(2) Total electricity supplied by a zero net energy renewable source, as set forth in section 398.4(h)(5) of the Public Utilities Code, that is not part of a net metering or other utility benefit;

(3) Total electricity supplied from other unspecified sources, as defined in section 398.2(e) of the Public Utilities Code, and other onsite sources of generation not reported to the local utility provider (e.g., generators, fuel cells) and the greenhouse gas emission intensity from these sources; and

(4) Average weighted greenhouse gas emission intensity considering all electricity use in subsections (f)(1)-(f)(3).

Authority: Section 26013, Business and Professions Code. Reference: Sections 26012 and 26050, Business and Professions Code.

§15021. Denial of License.

(a) The Department may deny an application for a new license or a renewal of a license for any reason specified in Business and Professions Code section 26057, and on any additional grounds including grounds for denial under section 15018 of this division, and grounds for discipline under the Act or this division.

(b) Upon denial of an application for a license or renewal of a license, the Department shall notify the applicant in writing of the reasons for denial, and the right to a hearing to contest the denial.

(c) The applicant may request a hearing to contest the denial by submitting a written request to the Department.

(1) The written request for a hearing must be postmarked within 30 calendar days of service of the notification of denial.

(2) If the written request for a hearing is not received within the required timeframe, the applicant's right to a hearing is waived.

(3) Upon timely receipt of the written request for hearing, the Department shall set a date for hearing to be conducted in accordance with chapter 5 (commencing with section 11500) of part 1 of division 3 of title 2 of the Government Code.

(d) If a license application is denied due to an owner's conviction history, the Department shall notify the applicant of the process for the owner to request a copy of their complete conviction history and question the accuracy or completeness of the record pursuant to Penal Code sections 11122 through 11127.

Authority: Section 26013, Business and Professions Code; Reference: Sections 26012, 26057 and 26058, Business and Professions Code.

§15023. Business Modifications.

Business modifications shall be made in accordance with the following:

(a) Changes to standard operating procedures may be made without providing notification to the Department, except as required by the Act or this division. Licensees shall maintain a copy of all current and prior operating procedures as required by section 15037 of this division.

(b) If at the time of licensure, a licensee employed less than 20 employees and later employs 20 or more employees, within 60 days of employing 20 or more employees, the licensee shall provide to the Department a notarized statement that the licensee will enter into a labor peace agreement and will abide by the terms of the agreement.

(1) Principles, guidelines, and requirements adopted pursuant to section 13149 of the Water Code and implemented by the State Water Resources Control Board, Regional Water Quality Control Boards, or California Department of Fish and Wildlife;

(2) Any conditions of licensure included pursuant to section 26060.1(b)(1) of the Business and Professions Code;

(3) Requirements of section 7050.5(b) of the Health and Safety Code if human remains are discovered during cultivation activities;

(4) Requirements for generators pursuant to section 16306;

(5) Requirements for pesticides pursuant to section 16307;

(6) Outdoor lights used for safety or security purposes are shielded and downward facing; and

(7) Lights used for indoor or mixed-light cultivation are shielded from sunset to sunrise to reduce nighttime glare.

Authority: Section 26013, Business and Professions Code. Reference: Sections 26013, 26060, 26066 and 26201, Business and Professions Code.

§16305. Renewable Energy Requirements.

(a) Beginning January 1, 2023, all holders of indoor, tier 2 mixed-light license types of any size, and all holders of nursery licenses using indoor or tier 2 mixed-light techniques shall ensure that electrical power used for commercial cannabis activity meets the average electricity greenhouse gas emissions intensity required by their local utility provider pursuant to the California Renewables Portfolio Standard Program in division 1, part 1, chapter 2.3, article 16 (commencing with section 399.11) of the Public Utilities Code.

(b) If a licensed cultivator's average weighted greenhouse gas emission intensity, as calculated and reported upon license renewal pursuant to section 15020, is greater than the local utility provider's greenhouse gas emission intensity, the licensee shall obtain carbon offsets to cover the excess in carbon emissions from the previous annual licensed period. The carbon offsets shall be purchased from one or more of the following recognized voluntary carbon registries:

(1) American Carbon Registry;

(2) Climate Action Reserve; or

(3) Verified Carbon Standard.

Authority: Section 26013, Business and Professions Code. Reference: Sections 26013, 26060, 26066 and 26201, Business and Professions Code.

§16306. Generator Requirements.

(a) For the purposes of this section, "generator" means a stationary or portable compression ignition engine as defined in title 17, California Code of Regulations, section

93115.4.

(b) Licensed cultivators using generators rated at fifty (50) horsepower and greater shall demonstrate compliance with the Airborne Toxic Control Measure for stationary or portable engines, as applicable, established in title 17, California Code of Regulations, sections 93115-93116.5. Compliance shall be demonstrated by providing a copy of one of the following to the Department upon request:

(1) For portable engines, a Portable Equipment Registration Certificate provided by the California Air Resources Board; or

(2) For portable or stationary engines, a Permit to Operate or other proof of engine registration, obtained from the Local Air District with jurisdiction over the licensed premises.

(c) Licensed cultivators using generators rated below fifty (50) horsepower shall comply with the following by 2023:

(1) Either subsection (1)(A) or (1)(B):

(A) Meet the "emergency" definition for portable engines in title 17, California Code of Regulations, section 93116.2(a)(12), or the "emergency use" definition for stationary engines in title 17, California Code of Regulations, section 93115.4(a)(30); or

(B) Operate eighty (80) hours or less in a calendar year; and

(2) Either subsection (2)(A) or (2)(B):

(A) Meet Tier 3 with Level 3 diesel particulate filter requirements in title 13, California Code of Regulations, sections 2700-2711; or

(B) Meet Tier 4 requirements, or current engine requirements if more stringent, in title 40, Code of Federal Regulations, chapter I, subchapter U, part 1039, subpart B, section 1039.101.

(d) All generators used by licensed cultivators shall be equipped with non-resettable hour-meters. If a generator does not come equipped with a non-resettable hour-meter, an after-market non-resettable hour-meter shall be installed.

Authority: Section 26013, Business and Professions Code. Reference: Sections 26013, 26060, 26066 and 26201, Business and Professions Code.

§16307. Pesticide Use Requirements.

(a) Licensed cultivators shall comply with all applicable pesticide statutes and regulations enforced by the Department of Pesticide Regulation.

(b) For all pesticides that are exempt from registration requirements, licensed cultivators shall comply with all applicable pesticide statutes and regulations enforced by the Department of Pesticide Regulation and the following pesticide application and storage protocols:

(1) Comply with all pesticide label directions;

(2) Store chemicals in a secure building or shed to prevent access by wildlife;

Trinity PUD

Rate Discussion

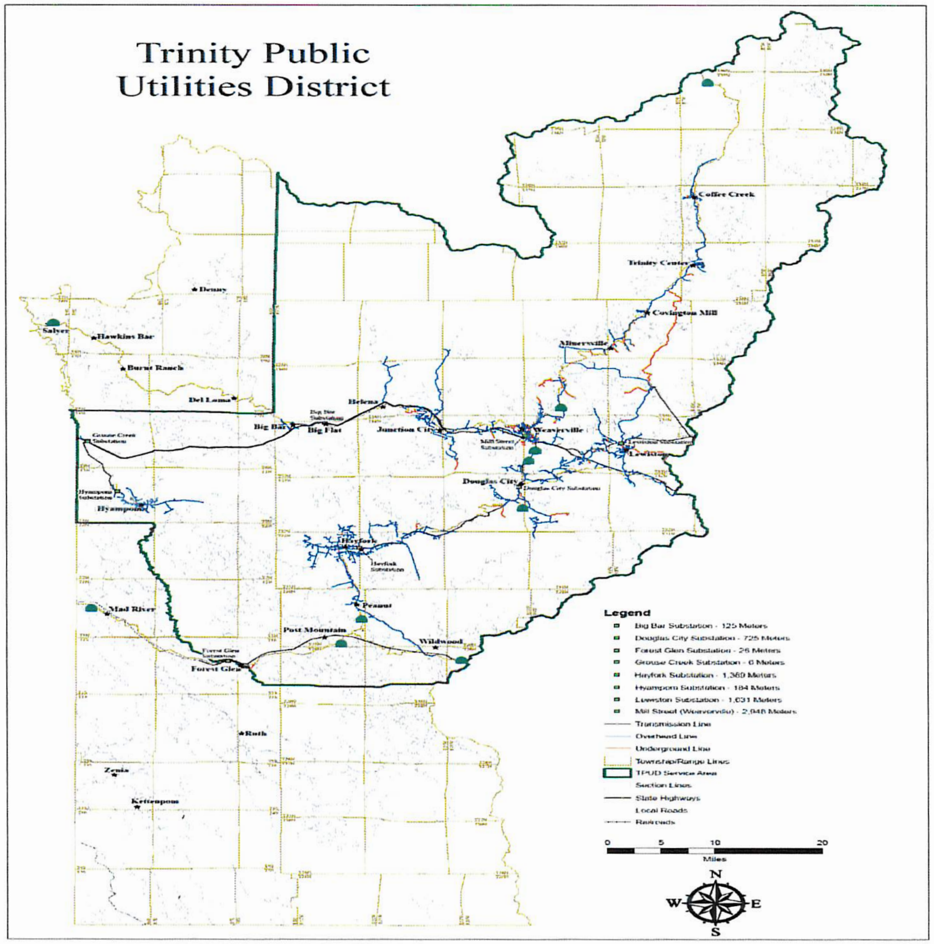
Background

- TPUD began delivering power to Weaverville in 1982 taking advantage of the 1955 Trinity River Division Act that set aside 25% of the power generated from Trinity River water for "the use of the citizens of Trinity County"
- TPUD has a "first preference" right to purchase power from the Western Area Power Administration (WAPA)
- TPUD's first preference power satisfies California's renewable power mandate under SB100
- In 1993 TPUD purchased powerline and substation assets from PG&E allowing the PUD to provide power to the areas outside of Weaverville expanding to the current service area.

Additional Background

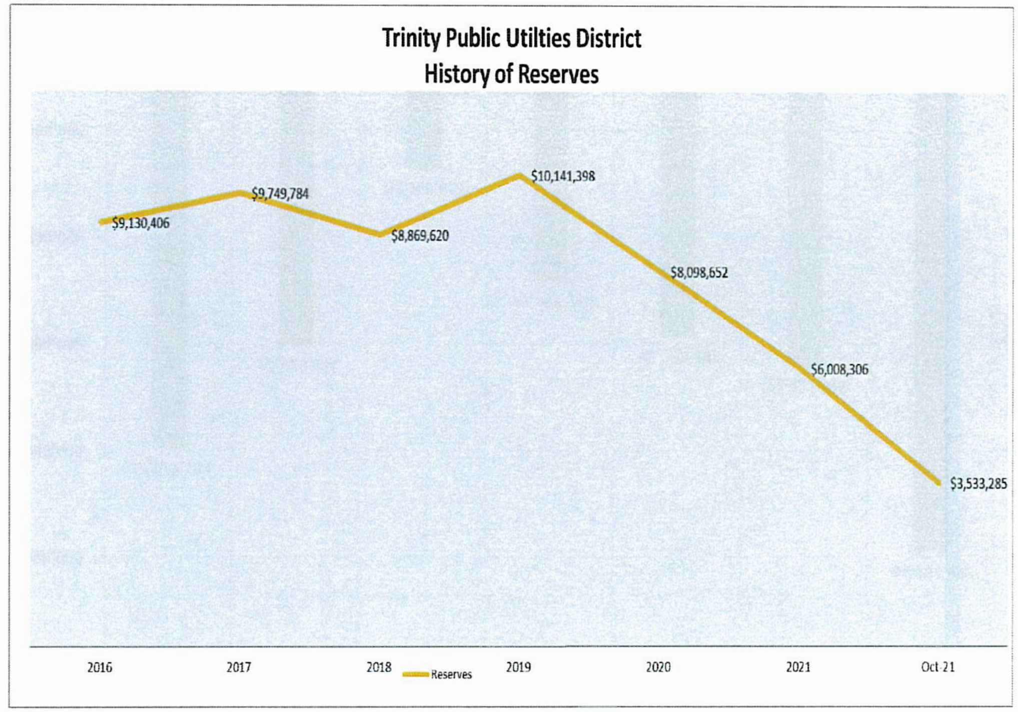
- Today TPUD has 25 employees that provide electric service to 7,350 customers located over a 2,200 square mile service territory
- The PUD has 9 substations and more than 700 miles of power lines
- 94% of the power is delivered over WAPA and TPUD transmission lines with the remaining 6% delivered from PG&E transmission lines
- All of the power is renewable, emission free hydropower from the Central Valley Project

Trinity Public Utilities District



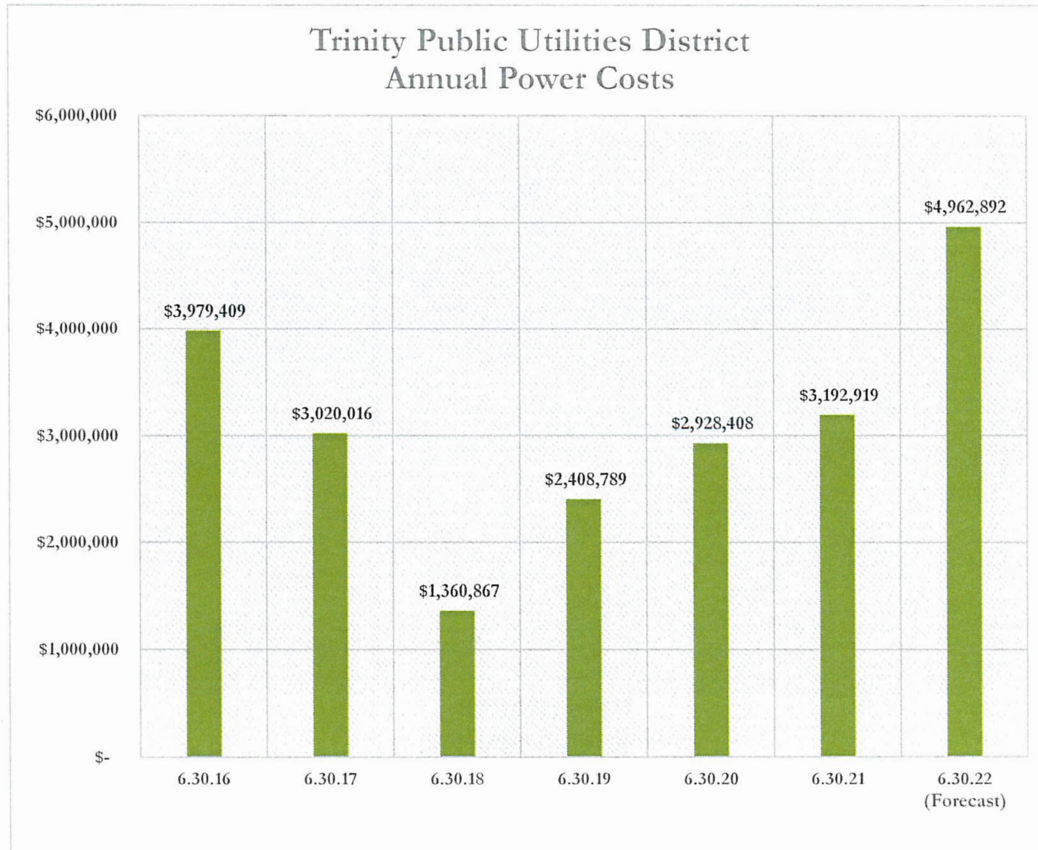
Decline in Reserves

- Reserves began to decline in 2019 as capital expenditures increased
- Power costs have also increased during this time period
- Increased cost for vegetation management (SB 247 mandated a 40% increase in tree trimmer wages)
- ROW Expansion Project
- Capital Investments to Serve New Load
- Helena Fire settlement resulted in a loss of wildfire liability insurance



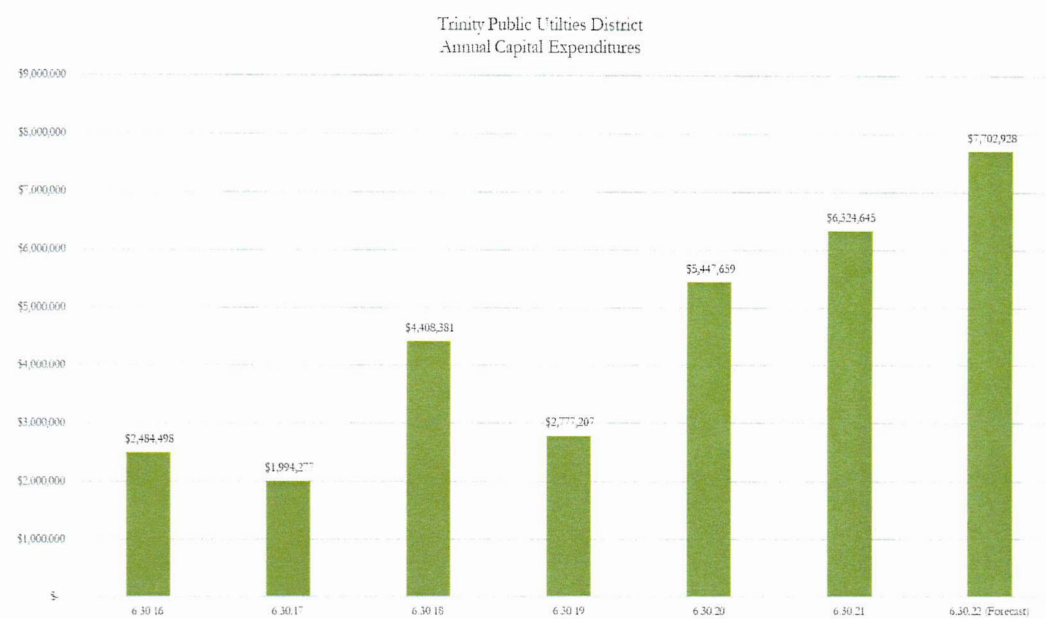
Increase in Power Cost

- Pervasive drought dramatically increases power cost
- Increased water releases to the Trinity River (versus diversions to the Sacramento River) both increase power cost and reduce power available
- Inflation has accelerated increasing the cost to operate the hydro power plants and maintain the high voltage transmission system



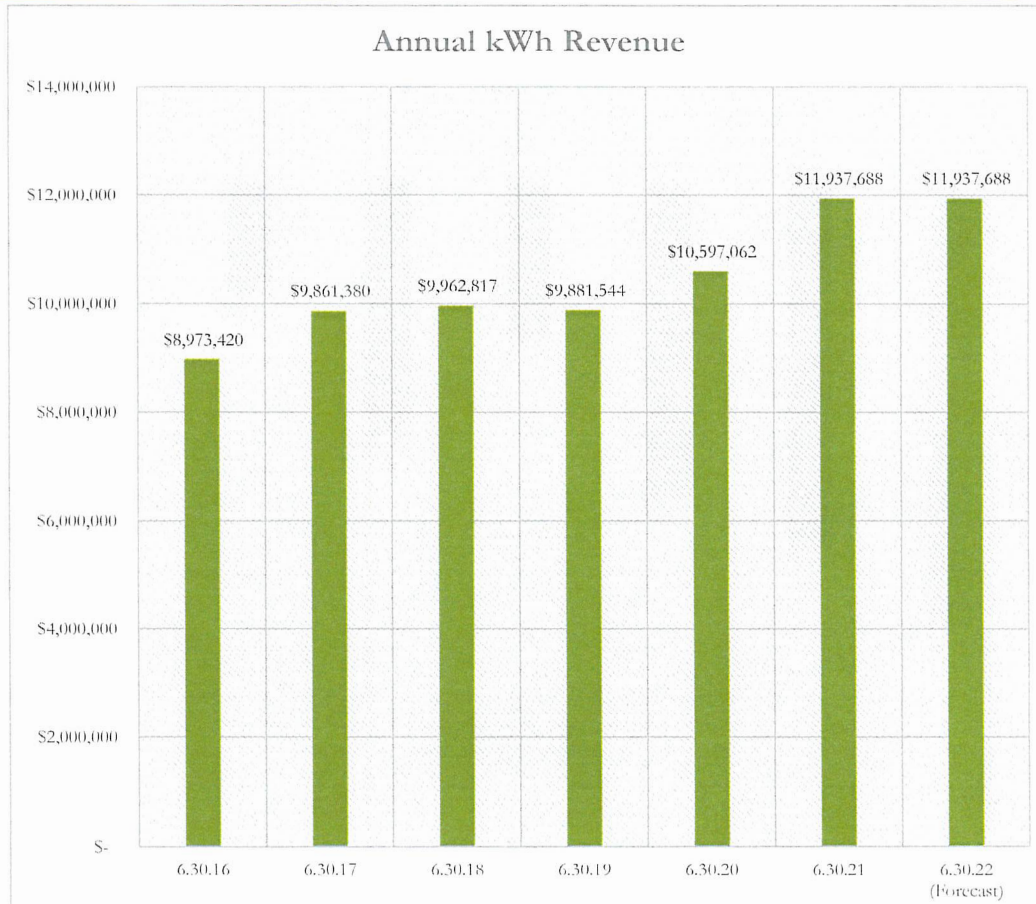
Capital Expenditures

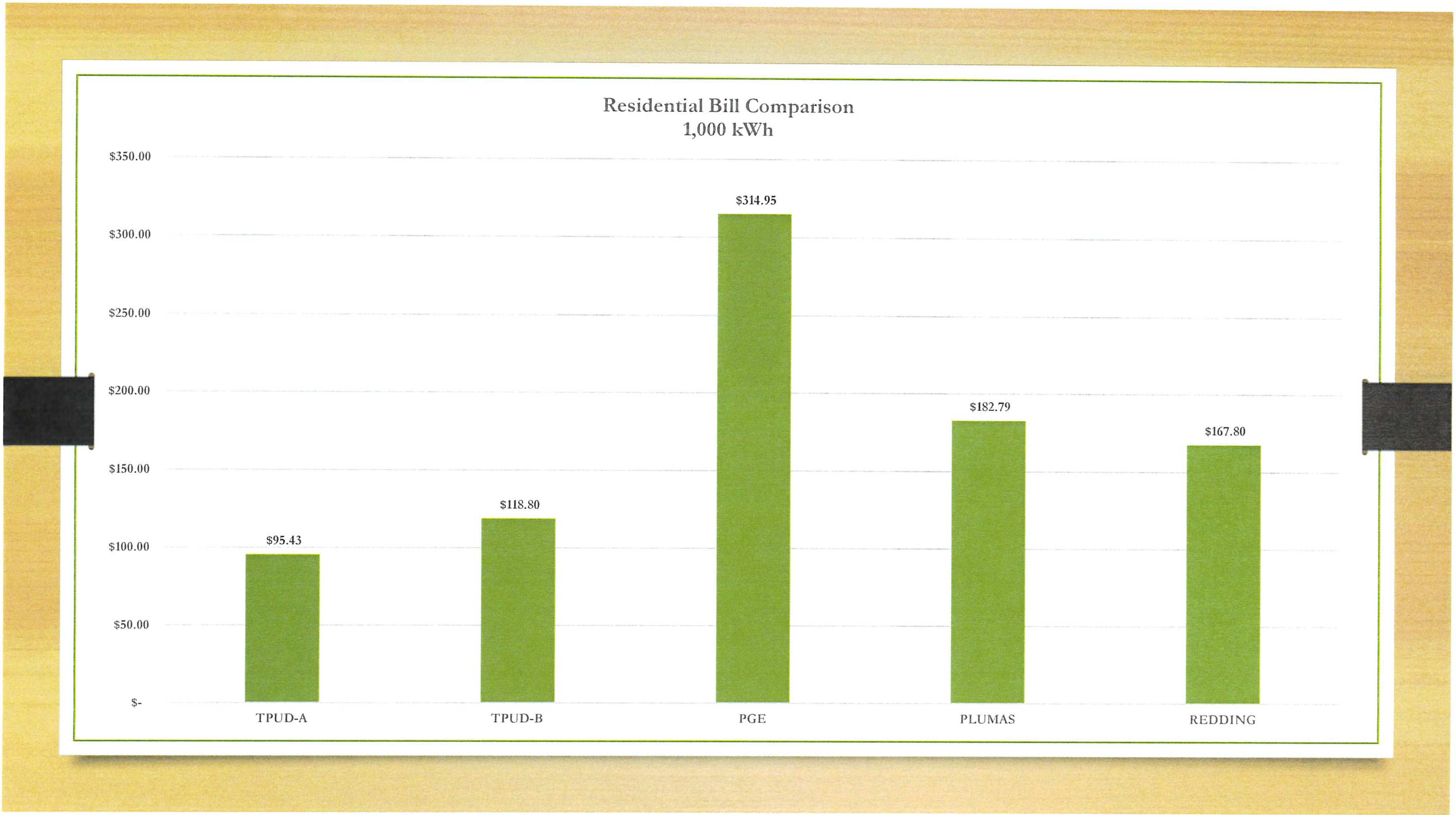
- Significant capital expenditures to serve new load – approx. $6 million spent with another $7 million identified
- Significant increase in pole replacements as a result of California Wildfire Legislation (AB 1054 in July 2019)
- ROW Expansion – approx. $2 million spent to date

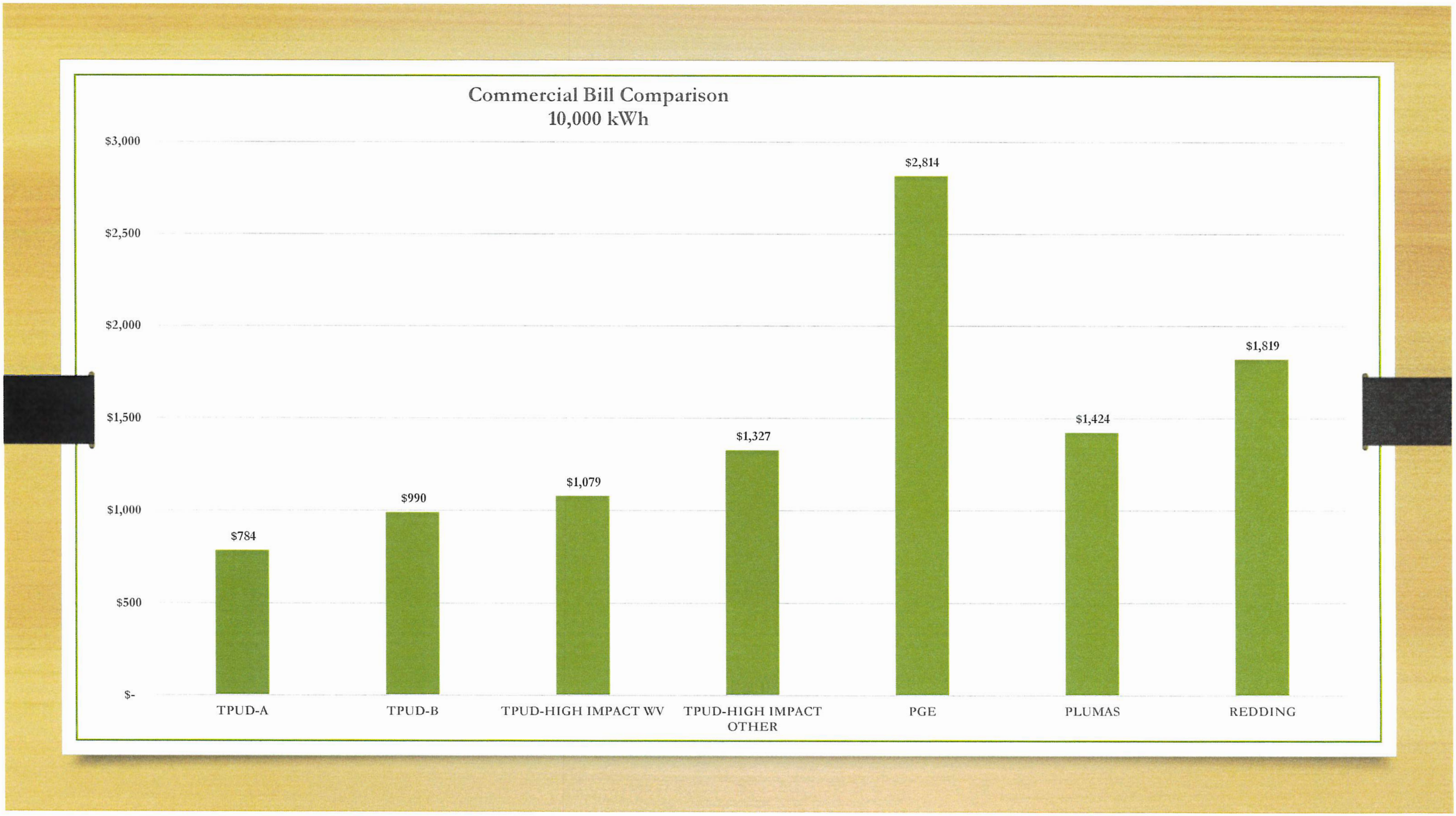


Revenue from Power Sales has Increased

- TPUD has added significant new load since 2019
- All of the new load is in the High Impact and commercial categories
- Residential load has declined slightly
- Additional system investments are required in order to add new load




Residential Bill Comparison
1,000 kWh
$350.00
$300.00
$250.00
$200.00
$150.00
$100.00
$50.00
$-
$95.43
$118.80
$314.95
$182.79
$167.80
TPUD-A
TPUD-B
PGE
PLUMAS
REDDING


Commercial Bill Comparison
10,000 kWh
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$-
$784
$990
$1,079
$1,327
$2,814
$1,424
$1,819
TPUD-A
TPUD-B
TPUD-HIGH IMPACT WV
TPUD-HIGH IMPACT OTHER
PGE
PLUMAS
REDDING

Current Rates

METHOD 1 - RATES							0.0285	
	INPUT: KWH USED	FLAT CHARGE	PUBLIC BENEFITS CHARGE ON FLAT CHARGE	BASE RATE	DROUGHT RELIEF SURCHARGE	CALIFORNIA ENERGY TAX RATE	PUBLIC BENEFITS CHARGE	FINAL BILL
Residential - Weaverville	1000	$ 24.00	$ 0.68	$0.05545	$0.01300	0.00030	$0.0020	$95.43
Residential - Other	1000	$ 24.00	$ 0.68	$0.07822	$0.01300	0.00030	$0.0026	$118.80
Commercial - Weaverville	3500	$ 36.00	$ 1.03	$0.07258	$0.01300	0.00030	$0.0025	$346.36
Commercial - Other	3500	$ 36.00	$ 1.03	$0.09261	$0.01300	0.00030	$0.0031	$418.57
High Impact Load - WV	10000	$ 45.00	$ 1.28	$0.08710	$0.01300	0.00030	$0.0029	$1,079.28
High Impact Load - Other	10000	$ 45.00	$ 1.28	$0.11113	$0.01300	0.00030	$0.0036	$1,326.58

Restructured Rates

METHOD 1 - RATES							0.0285			
	INPUT: KWH USED	FLAT CHARGE	PUBLIC BENEFITS CHARGE ON FLAT CHARGE	BASE RATE	DROUGHT RELIEF SURCHARGE	CALIFORNIA ENERGY TAX RATE	PUBLIC BENEFITS CHARGE	FINAL BILL	$$ Increase	%% Increase
Residential - Weaverville	1000	$ 38.00	$ 1.08	$0.06422	$0.01300	0.00030	$0.0023	$118.90	$23.47	25%
Residential - Other	1000	$ 38.00	$ 1.08	$0.06422	$0.01300	0.00030	$0.0023	$118.90	$0.10	0%
Commercial - Weaverville	3500	$ 57.00	$ 1.62	$0.08259	$0.01300	0.00030	$0.0028	$404.04	$57.68	17%
Commercial - Other	3500	$ 57.00	$ 1.62	$0.08259	$0.01300	0.00030	$0.0028	$404.04	-$14.53	-3%
High Impact Load - WV	10000	$ 120.00	$ 3.42	$0.14600	$0.01300	0.00030	$0.0046	$1,762.42	$683.14	63%
High Impact Load - Other	10000	$ 120.00	$ 3.42	$0.14600	$0.01300	0.00030	$0.0046	$1,762.42	$435.84	33%

Proposed Change in Rates

Current Rates

METHOD 1 - RATES							0.0285	
	INPUT: KWH USED	FLAT CHARGE	PUBLIC BENEFITS CHARGE ON FLAT CHARGE	BASE RATE	DROUGHT RELIEF SURCHARGE	CALIFORNIA ENERGY TAX RATE	PUBLIC BENEFITS CHARGE	FINAL BILL
Residential - Weaverville	1000	$ 24.00	$ 0.68	$0.05545	$0.01300	0.00030	$0.0020	$95.43
Residential - Other	1000	$ 24.00	$ 0.68	$0.07822	$0.01300	0.00030	$0.0026	$118.80
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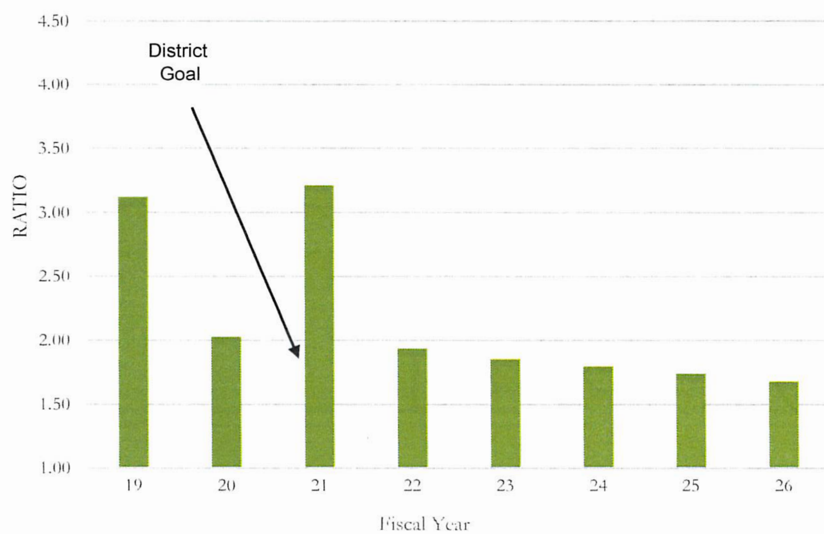
Commercial - Other	3500	$ 36.00	$ 1.03	$0.09261	$0.01300	0.00030	$0.0031	$418.57
High Impact Load - WV	10000	$ 45.00	$ 1.28	$0.08710	$0.01300	0.00030	$0.0029	$1,079.28
High Impact Load - Other	10000	$ 45.00	$ 1.28	$0.11113	$0.01300	0.00030	$0.0036	$1,326.58

Restructured Rates

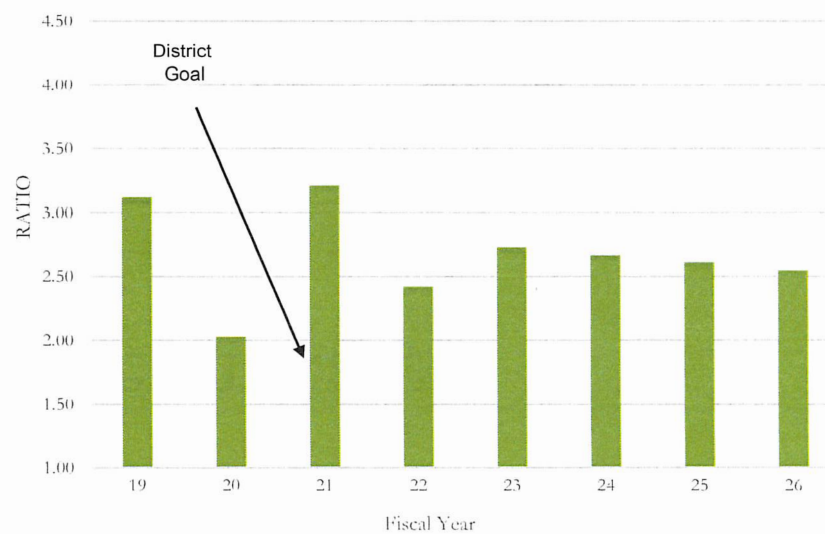
METHOD 1 - RATES							0.0285			
	INPUT: KWH USED	FLAT CHARGE	PUBLIC BENEFITS CHARGE ON FLAT CHARGE	BASE RATE	DROUGHT RELIEF SURCHARGE	CALIFORNIA ENERGY TAX RATE	PUBLIC BENEFITS CHARGE	FINAL BILL	$$ Increase	%% Increase
Residential - Weaverville	1000	$ 38.00	$ 1.08	$0.06422	$0.01300	0.00030	$0.0023	$118.90	$23.47	25%
Residential - Other	1000	$ 38.00	$ 1.08	$0.06422	$0.01300	0.00030	$0.0023	$118.90	$0.10	0%
Commercial - Weaverville	3500	$ 57.00	$ 1.62	$0.08259	$0.01300	0.00030	$0.0028	$404.04	$57.68	17%
Commercial - Other	3500	$ 57.00	$ 1.62	$0.08259	$0.01300	0.00030	$0.0028	$404.04	-$14.53	-3%
High Impact Load - WV	10000	$ 120.00	$ 3.42	$0.14600	$0.01300	0.00030	$0.0046	$1,762.42	$683.14	63%
High Impact Load - Other	10000	$ 120.00	$ 3.42	$0.14600	$0.01300	0.00030	$0.0046	$1,762.42	$435.84	33%

Debt Service Coverage Ratio Comparison

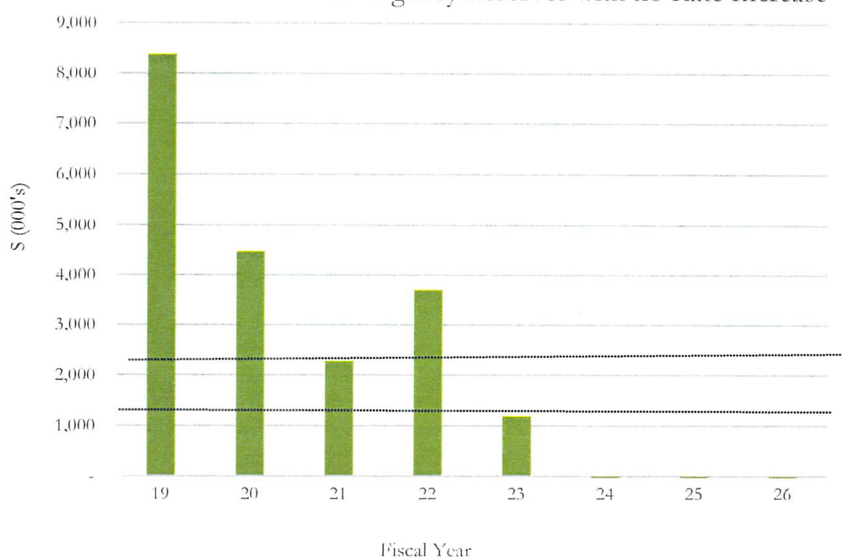
Debt Service Coverage Ratio No Rate Increase

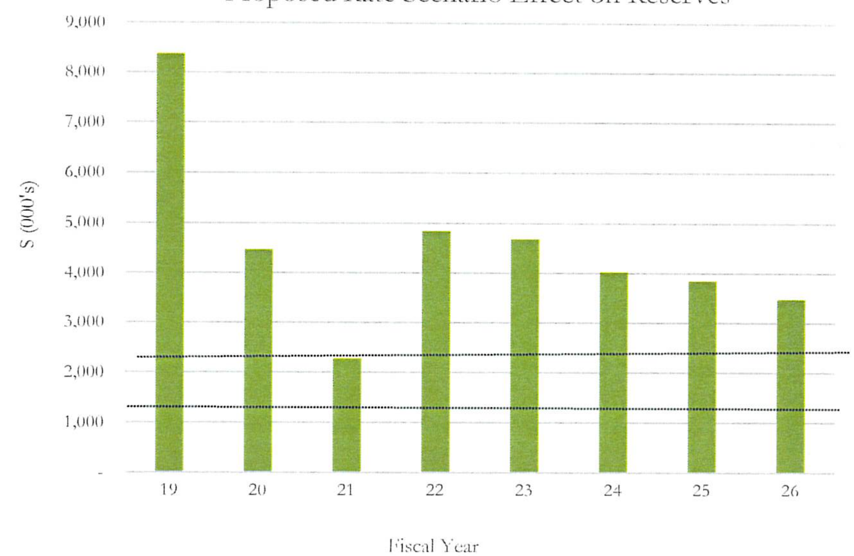


Debt Service Coverage Ratio with Rate Restructuring



Contingency Reserves Comparison





Questions?