2027 Preliminary Budget

August 18, 2026

Katie Smith, Budget & Reporting Specialist

Powering our way of life.

2027 Preliminary Budget

- State law requires Grant PUD to file a preliminary budget by the first Monday in September, making August the first formal Commission touchpoint
- Today's filing begins a multi-month review through refinement, public hearing, and final adoption in November
- **Recommendation:** approve the resolution to file the preliminary budget

2027 Preliminary Budget

Budget at a Glance

Category	2026 Budget	2027 Budget	Change ($)	Change (%)
O&M	$264.0M	$302.1M	+$38.1M	+14.4%
Capital	$347.6M	$329.3M	-$18.3M	-5.3%
Debt Service	$67.1M	$154.6M	+$87.5M	+130.4%
Taxes	$24.5M	$25.0M	+$0.5M	+2.0%
Total Gross Expenses	**$703.3M**	**$811.0M**	**+$107.7M**	**+15.3%**

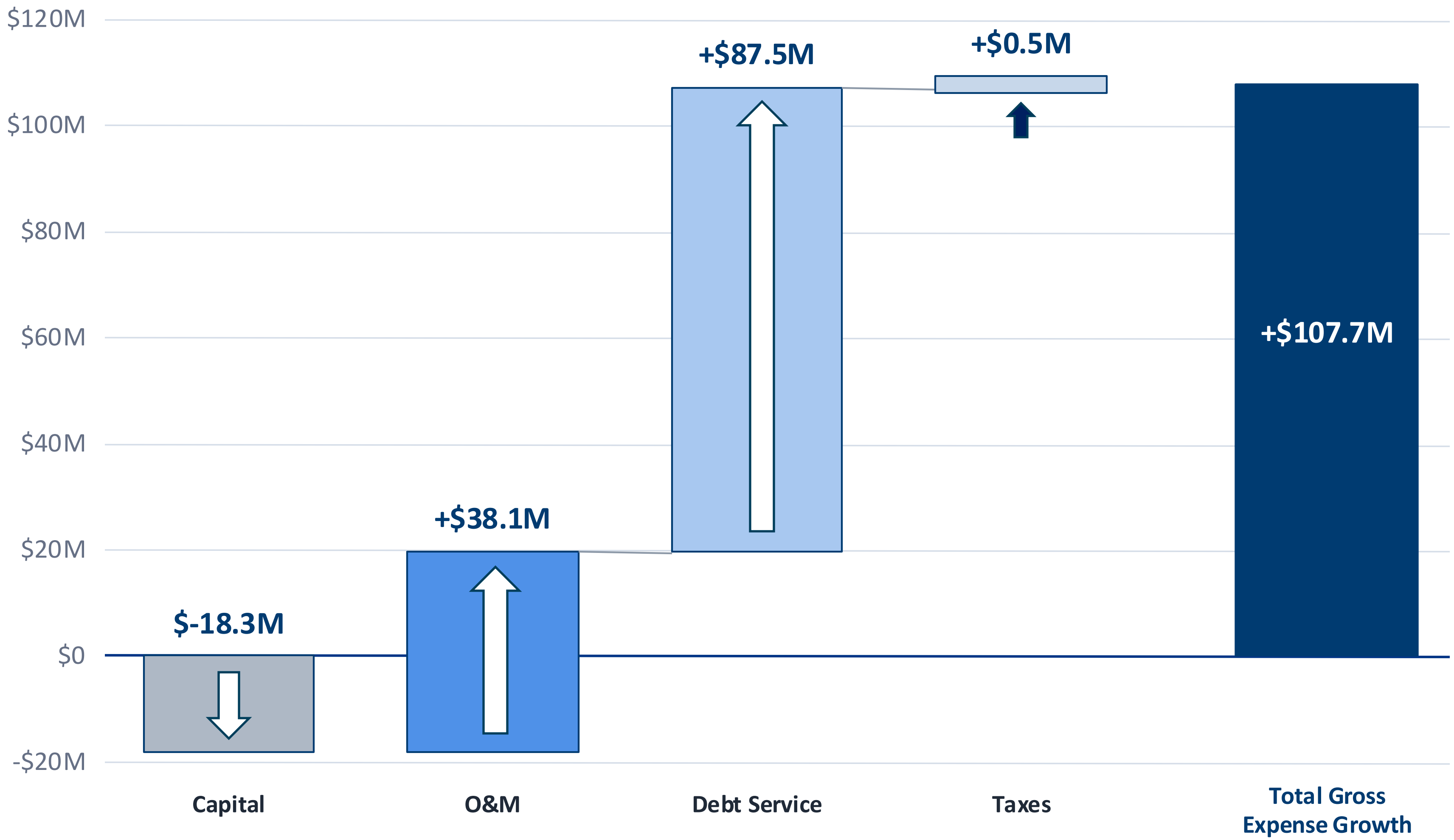
Note: Dollar amounts are shown in millions ($M) and are rounded to the nearest $0.1 million. Totals and percentages may not sum due to rounding.

Note: Debt Service for 2027 is higher due to the $90M CREBs bullet maturity payment.
Funds have been set aside in sinking funds and annually included in the Debt Service Coverage calculation.

2027 Preliminary Budget

Breakdown of Gross Expense Growth

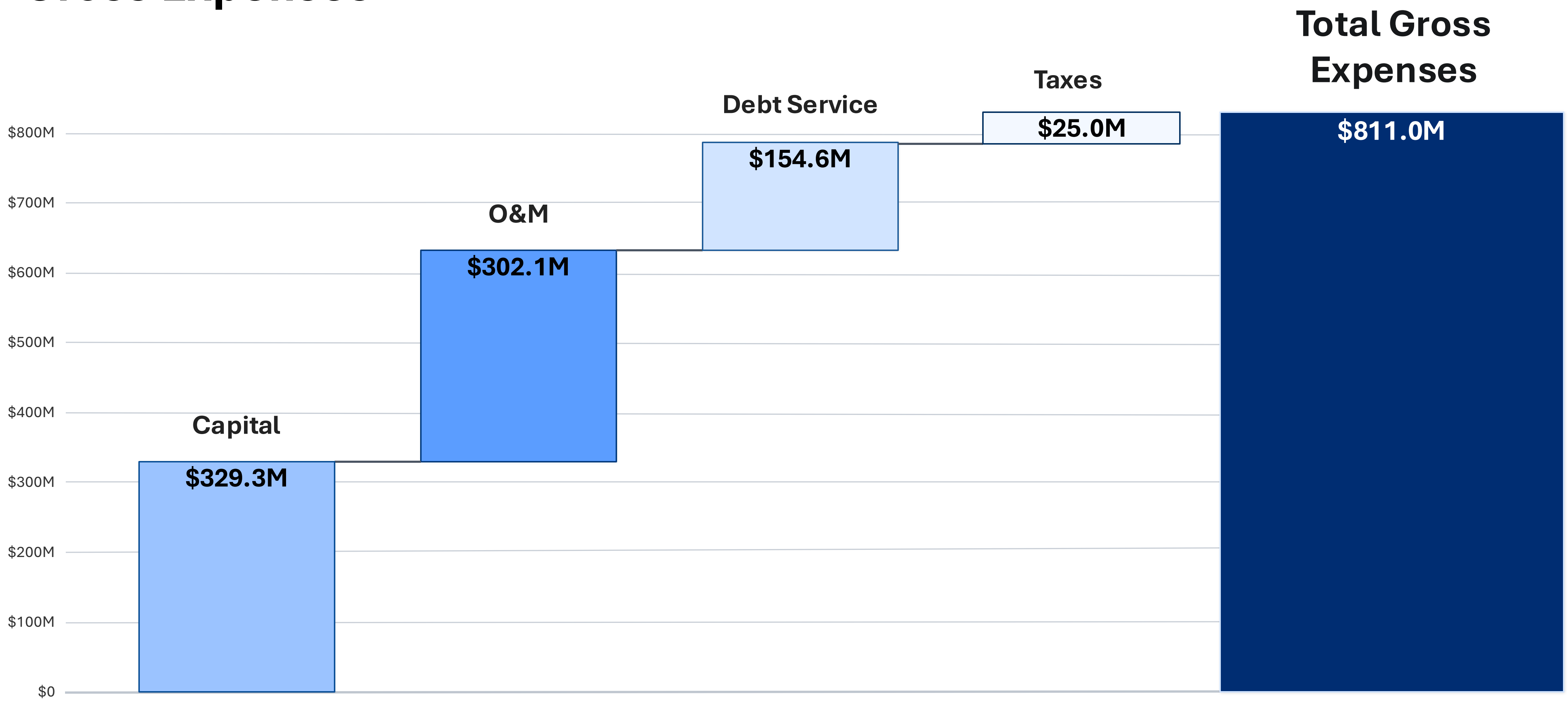
Change from the 2026 budget to the 2027 preliminary budget



Growth is concentrated in O&M and the planned debt repayment, partially offset by lower capital spending.

2027 Preliminary Budget

2027 Gross Expenses



2027 Preliminary Budget

O&M

Strategic energy investments, labor costs, and TEA membership are the primary areas of growth.

2027 O&M

$302.1M

Operations & Maintenance

+$38.1M

Increase from 2026 Budget

PRIMARY COST DRIVERS

+$18.2M — **SMR & Geothermal Exploration & Discovery**

X-Energy, Geothermal and TerraPower

+$15.5M — **Salaries, Wages, and Benefits**

Labor cost increase, workforce growth

+$4.9M — **The Energy Authority**

Power marketing, market participation, and energy risk management services

Growth is concentrated in strategic energy work, labor, and TEA membership.

2027 Preliminary Budget

Capital

Capital investments remain focused on District priorities while improving alignment to project timing.

Total of Top Four Projects

PROJECT / PROGRAM	PHASE	2027 BUDGET
QTEP Program	Planning	$117.8M
FMPI - PDF_PD Facilities-SC1	Execution	$104.0M
Turbine/Generator Program	Execution	$48.9M
PR Spillway Stability Improvements	Execution	$35.4M

2027 CAPITAL

Budget Overview

$329.3M

Total Capital Budget

-$18.3M

Decrease from 2026 Budget

Amounts rounded to the nearest $100,000.

2027 Preliminary Budget

Debt Service Drivers

Debt service includes the planned $90M CREBs cash payment in 2027.

2027 DEBT SERVICE

$154.6M

Debt Service Budget

+$87.5M

Increase from 2026 Budget

PRIMARY COST DRIVER

$90M

CREBs Bond Maturity Payment

The payment for 2027 is included in the 2027 debt service (total debt payments). Annual sinking fund payments have been set aside and included in the Debt Service Coverage calculation (per bond covenants).

2027 Preliminary Budget

Budget Roadmap & Commission Touchpoints

BUDGET DEVELOPMENT

JAN–JULY	AUGUST	SEPTEMBER
PLAN	**FILE**	**REFINE**
Build budget	Preliminary filing	Leadership review

OCTOBER	LATE OCT–NOV	NOVEMBER
REVIEW	**UPDATE**	**ADOPT**
Public + Commission	Budget updates	Final approval

COMMISSION

Key Dates

AUG 18	Preliminary Presentation
AUG 25	Preliminary filing
OCT 13	Proposed Budget Presentation
OCT 20	Proposed Budget Q&A
OCT 27	Additional Review Prior to Hearing
OCT 27	**Public Hearing | 2pm & 6pm**
NOV 10	Final Budget Presentation
NOV 17	Final Budget Q&A
NOV 24	**Final adoption**

Closing Summary

- State law requires the preliminary budget be filed by the first Monday in September
- Approve the resolution to file the Preliminary Budget on August 25
- Refine, hold public hearing, and adopt the final budget through November

Thank you!

APPENDIX

2027 Preliminary Budget

Exhibit A

NET BUDGET	2026 BUDGET	2026 FORECAST	2027 BUDGET	Budget Change ($)	Budget Change (%)
Operations & Maintenance (Includes adjustments)	$264.0 M	$261.4 M	$302.1 M	+$38.1 M	+14.4%
Taxes	$24.5 M	$24.1 M	$25.0 M	+$0.5 M	+2.0%
Total Capital	$347.6 M	$346.6 M	$329.3 M	-$18.3 M	-5.3%
Electric System Capital	$257.9 M	$255.8 M	$221.1 M	-$36.8 M	-14.3%
Priest Rapids Project Capital	$89.7 M	$90.9 M	$108.2 M	+$18.5 M	+20.6%
Debt Service	$67.1 M	$67.1 M	$154.6 M	+$87.5 M	+130.4%
Total Gross Expenses	**$703.3 M**	**$699.2 M**	**$811.0 M**	**+$107.7 M**	**+15.3%**
EXPENSE OFFSETS					
Contributions in Aid of Construction	($13.2 M)	($5.8 M)	($4.4 M)	-$8.8 M	-66.7%
Sales to Power Purchasers at Cost	($34.3 M)	($28.8 M)	($38.0 M)	+$3.7 M	+10.8%
Net Power (+ Expense, - Revenue)	($235.8 M)	($320.9 M)	($174.6 M)	-$61.2 M	-26.0%
Total Offsets	**($283.4 M)**	**($355.6 M)**	**($217.0 M)**	**-$66.4 M**	**-23.4%**
TOTAL EXPENSES AFTER OFFSETS	**$419.9 M**	**$343.6 M**	**$594.0 M**	**+$174.1 M**	**+41.5%**

Expense Offsets: $ and % Change reflect the actual increase/decrease in each offsetting item.

Note: Dollar amounts are shown in millions ($M) and are rounded to the nearest $0.1 million. Totals and percentages may not sum due to rounding.

2027 Preliminary Budget

Exhibit B

NET POSITION	2026 BUDGET	2026 FORECAST	2027 BUDGET	Budget Change ($)	Budget Change (%)
CONSOLIDATED OPERATIONAL PERFORMANCE					
REVENUE					
Sales to Power Purchasers at Cost	$34.3 M	$28.8 M	$38.0 M	+$3.7 M	+10.8%
Retail Energy Sales	$314.4 M	$295.8 M	$337.2 M	+$22.8 M	+7.3%
Net Power (Net Wholesale + Other Power Revenue)	$235.8 M	$320.9 M	$174.6 M	-$61.2 M	-26.0%
Fiber Optic Network Sales	$14.1 M	$15.4 M	$14.4 M	+$0.3 M	+2.1%
Other Revenues	$4.1 M	$3.4 M	$4.1 M	$0.0 M	0.0%
EXPENSES					
Operating Expenses	($264.0 M)	($261.4 M)	($302.1 M)	+$38.1 M	+14.4%
Taxes	($24.5 M)	($24.1 M)	($25.0 M)	+$0.5 M	+2.0%
Net Operating Income or Loss Before Depreciation	**$314.2 M**	**$378.9 M**	**$241.2 M**	**-$73.0 M**	**-23.2%**
Depreciation and amortization	($90.3 M)	($93.0 M)	($92.5 M)	+$2.2 M	+2.4%
NET OPERATING INCOME OR LOSS	**$223.9 M**	**$285.8 M**	**$148.7 M**	**-$75.2 M**	**-33.6%**
OTHER REVENUES OR EXPENSES					
Interest, debt and other income	$10.7 M	$2.9 M	$0.1 M	-$10.6 M	-99.1%
CIAC (Money paid by customers to build infrastructure)	$13.2 M	$5.8 M	$4.4 M	-$8.8 M	-66.7%
CHANGE IN NET POSITION (BOTTOM LINE)	**$247.9 M**	**$294.6 M**	**$153.2 M**	**-$94.7 M**	**-38.2%**

Note: Dollar amounts are shown in millions ($M) and are rounded to the nearest $0.1 million. Totals and percentages may not sum due to rounding.

2027 Preliminary Budget

Metrics

KEY METRICS	TARGET	2026 BUDGET	2026 FORECAST	2027 BUDGET
CHANGE IN NET POSITION		**$247.9 M**	**$294.6 M**	**$153.2 M**
LIQUIDITY (Measured at year end)				
Elect System Liquidity (Rev + R&C)	$215.0 M	$251.3 M	$380.6 M	$359.7 M
Days Cash On Hand	>250	332	444	432
LEVERAGE				
Consolidated Debt Service Coverage	>1.8X	5.45X	6.35X	4.50X
Consolidated Debt/Plant Ratio	≤60%	30.0%	30.0%	28.0%
PROFITABILITY				
Cons. Return on Net Assets	>8.3%	8.3%	10.0%	4.8%
Retail Op Ratio	≤128%	128.0%	152.0%	134.0%

Note: Dollar amounts are shown in millions ($M) and are rounded to the nearest $0.1 million. Totals and percentages may not sum due to rounding.

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Strategic Plan Update

August 18, 2026

Julie Pyper, VP – Head of Strategy

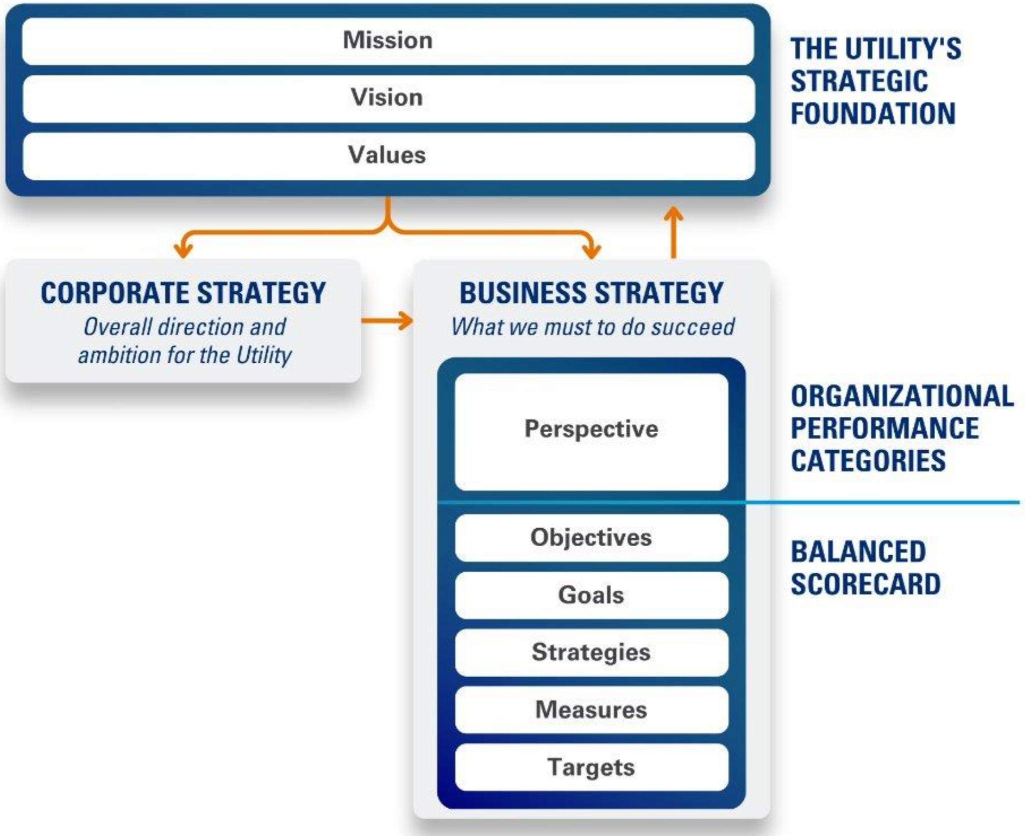
Powering our way of life.

Agenda & Executive Summary

Strategic Plan Update Purpose

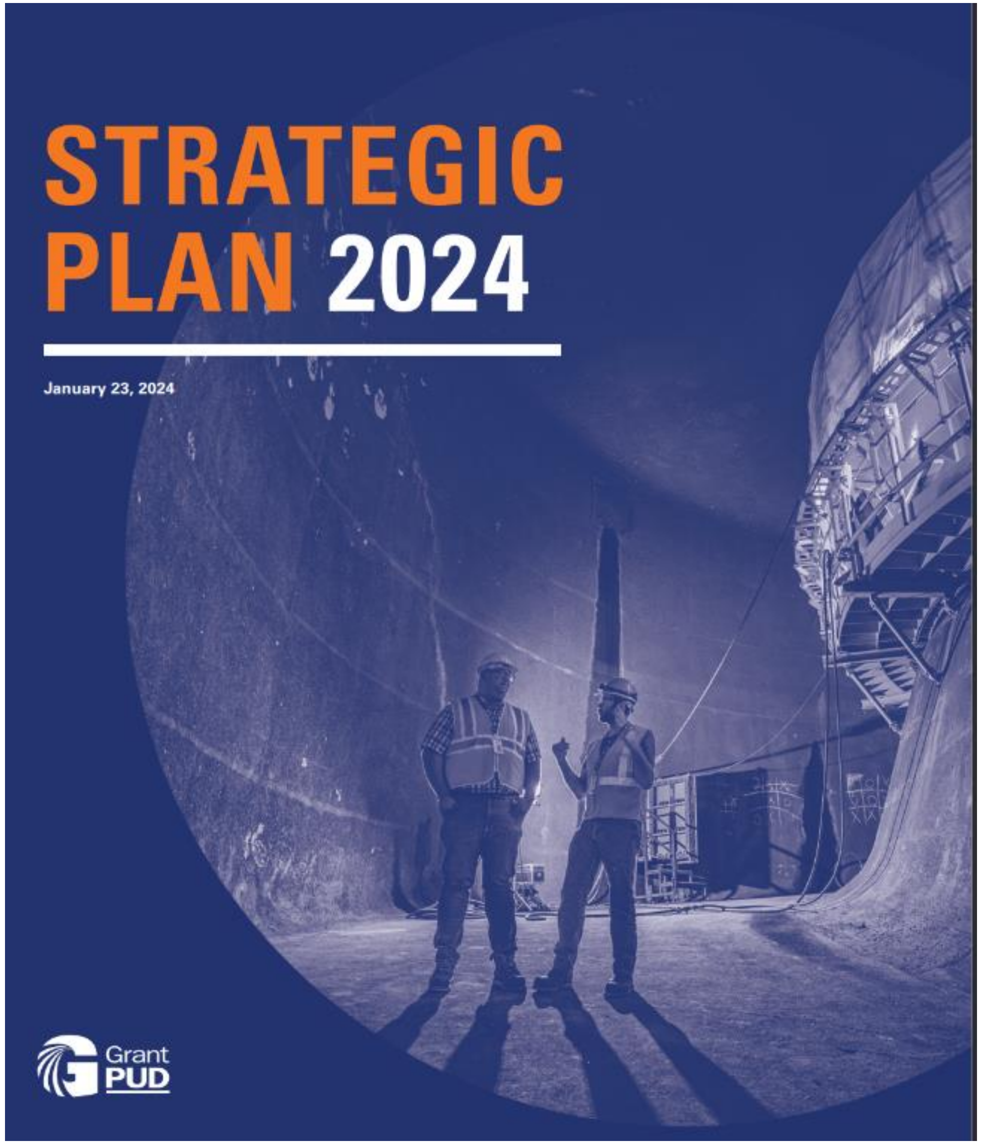
- **We've evolved:** Current Strategic Plan does not represent Grant PUD’s current or future state
  - Corporate Strategy
  - Business Strategy

- **Reflects Who We Are Now:** Updating provides current and clear understanding of us
  - Customers – current and future
  - Bonding Agencies
  - Rating Agencies
  - Possible employees
  - Interested parties



Strategic Plan Background

- Current Strategic Plan adopted January 23, 2024
- Since then, we've changed
  - Increased load growth
  - Customers
  - Transitioned to data driven performance
  - Organizational changes
  - New strategy framework
- The current plan's objectives, strategies and key metrics no longer reflect how the business is run or measured.



Draft Strategic Plan Approach

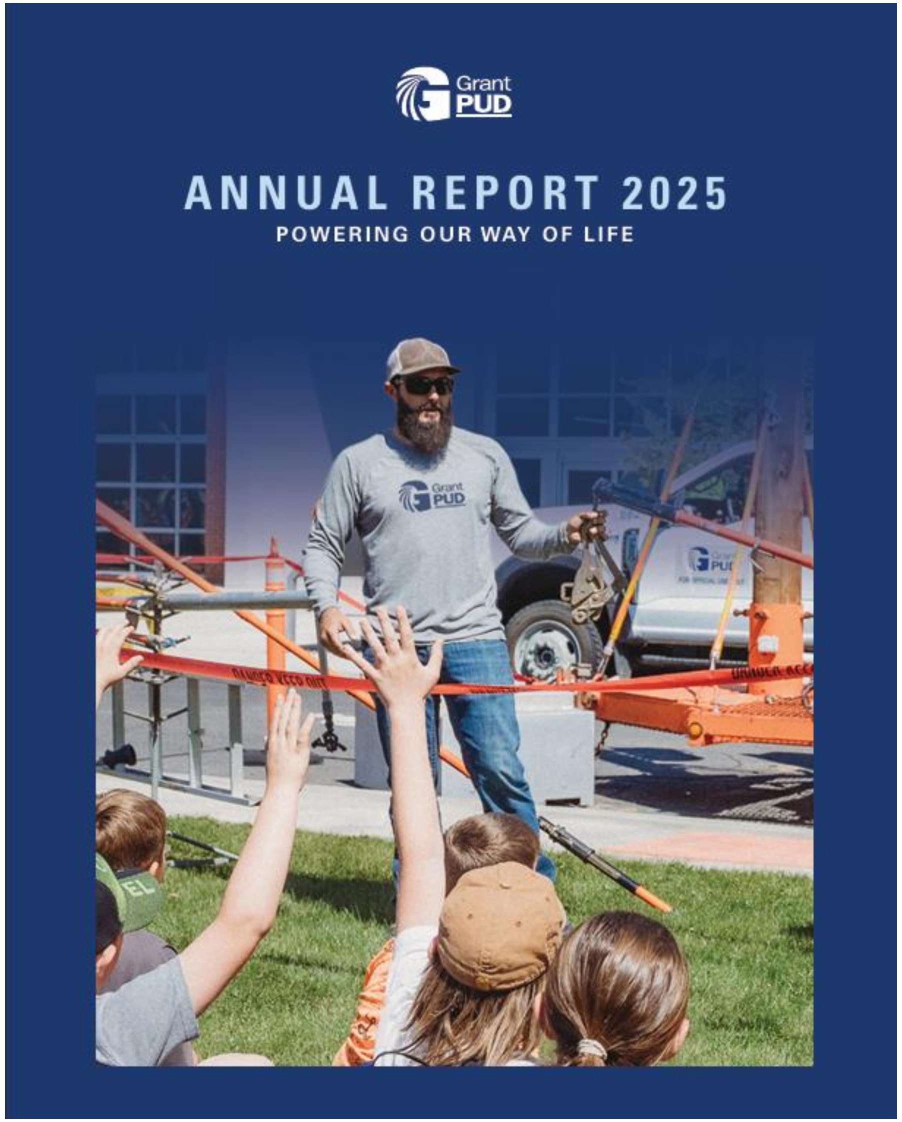
- Aligns with our new strategy framework
  - Corporate Strategy
  - Business Strategy

- Stronger consideration for our external audience
  - Expanded context on who we are, who we serve, our Commission and leadership, and our relationship with the Wanapum.

Draft Strategic Plan Design

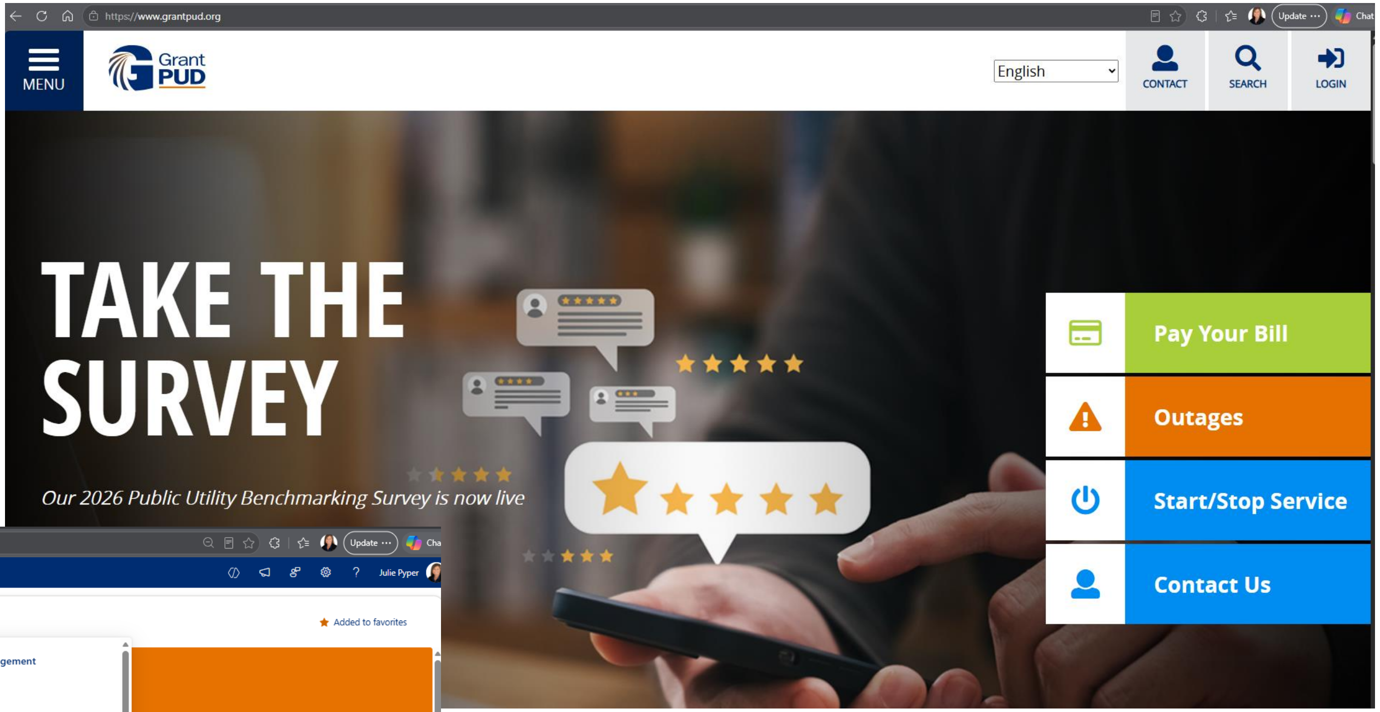
- Same design as the 2025 Annual Report

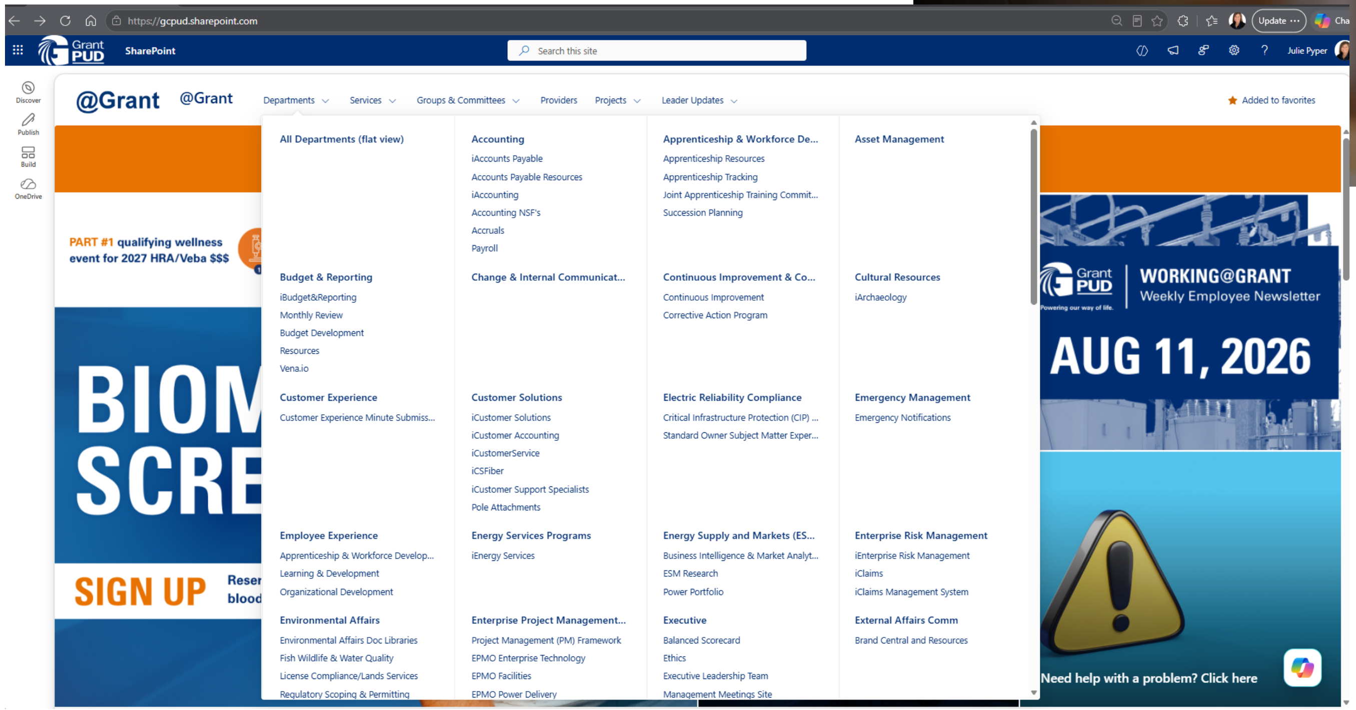
- Goal: Consistent look across externally published reports



Planned Strategic Plan Distribution

- Web based
- Limited printing on 8.5" X 11"
- Create a 11" X 17" poster





Timeline

Present Draft to Commission

Aug 18

Sep 8

Commission Comments Due

Oct 27

Finalization of 2026-2028 Strategic Plan

Commission Input and Guidance

- Design Draft
  - No comments necessary or expected

- Proposed content
  - Commission comments due 9/8
  - Provide verbally, electronically or handwritten – before or at 9/8 meeting
  - Considerations: Does the draft reflect Commission priorities? Communicates the intended direction? Any significant gaps or concerns?

- Available at September Commission Workshops as needed

Closing Summary

- Strategic Plan update reflects our current and future direction of our utility more accurately
- Commission comments on draft content due September 8
- Available at September Commission Workshops as needed

Strategic Plan Update

Thank you!

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2027-2030 Climate Commitment Act Cost Burden Forecast

August 18, 2026

James Dykes, Term Marketer
Mike Bradshaw, Sr. Manager Trading & Commercial Operations

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2027-2030 CCA Cost Burden Forecast

Executive Summary

Regulatory Mandate: State law directs the Washington State Department of Ecology (Ecology) to allocate no-cost carbon allowances to utilities by October 2026. This allocation mitigates the financial cost burden of the Climate Commitment Act (CCA) for retail customers during the second compliance period (2027–2030).

Forecast Requirements: Ecology determines the cost burden and subsequent allowance allocations using utility-specific demand and resource supply forecasts. To be accepted by Ecology, these forecasts must be formally approved by the utility’s governing board.

Methodology & Alignment: District staff developed the required forecast using a standard Washington utility methodology. The models directly align with Grant PUD's Clean Energy Implementation Plan (CEIP) under the Clean Energy Transformation Act (CETA).

Staff Recommendation: Staff recommends Commission approval of the utility-specific forecast to ensure formal, compliant submission to Ecology ahead of the September 2026 deadline.

2027-2030 CCA Cost Burden

Background

Program Genesis: Enacted via the CCA in 2021, launching Washington's cap-and-invest carbon market on January 1, 2023.

First Compliance Period: Established the initial multi-year compliance period spanning 2023–2026 for all covered utilities**.**

Methodology Foundation: Collaborative development with peer Washington utilities to submit utility-specific demand and supply forecasts to Ecology in 2022.

Ratepayer Protection: The District was allocated no-cost carbon allowances to insulate retail customers from the majority of the program's initial cost burdens

2027-2030 CCA Cost Burden

Analysis

Forecast Updates: District staff updated the demand and resource supply forecasts for the 2027–2030 compliance period.

Methodological Continuity: The updated projections apply the identical methodology developed and utilized during the previous 2022 submission cycle.

2027-2030 CCA Cost Burden

Recommendation

- Decision Request: Approve the Resolution authorizing the 2027-2030 CCA Cost Burden Forecast for submittal to the Washington State Department of Ecology.

2027-2030 CCA Cost Burden

Thank you!

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Rates & Pricing

2025 Cost-of-Service Analysis

Jeremy Stewart, Manager Rates & Pricing
Bret Hammond, Lead Financial Analyst
Amy Pheasant, Financial Analyst

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Introduction

- Rate Policy (Resolution 9111)
- Risk created by rate structures
- Options for simplification
- Customer-Bill relationship

COSA – Revenue Perspective

Charges Perspective

Functions Perspective

Grant PUD

Segments and Rate Classes

Retail Electric customers are organized into Segments and Rate Classes

Core

Residential
General Service
Irrigation
Ag Service

Organic growth

Inelastic demand

System growth = Risk

Tier 1

Lg General Service
Industrial
Industrial Ag

Step-change growth

Elastic demand

System growth = Risk and Opportunity

Tier 2

Large Industrial
Evolving Industry
Commercial EV Charging
High Density Compute

Rapid & speculative growth

Elastic demand

Growth = Business opportunity

Segments have similar:

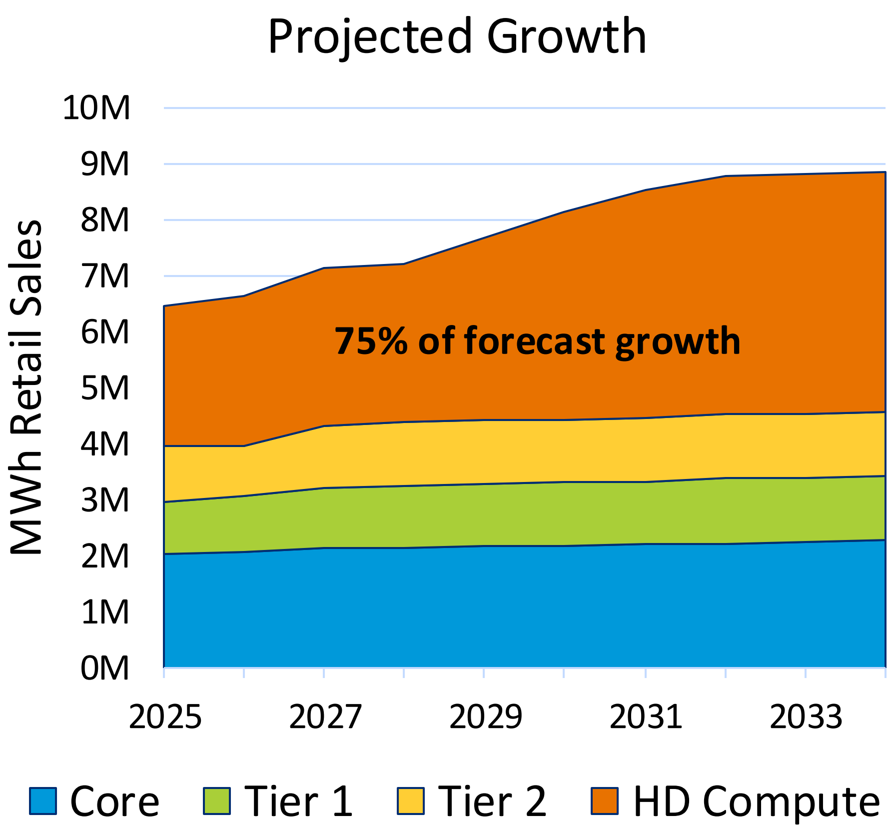
- Growth
- Price elasticity
- System growth risk

Rate Classes have similar:

- Load profiles
- Customer service needs
- Unique risk profiles

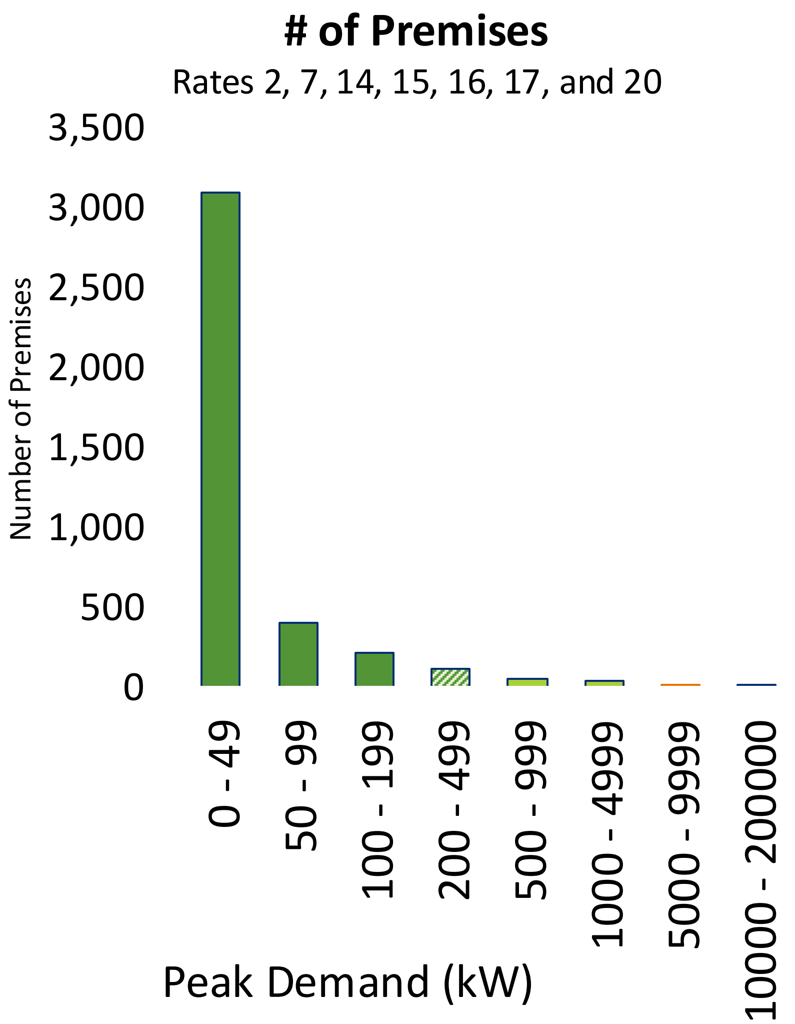
Recommendation: Align Customers With Growth

Create a new High-Density Compute rate (Rate 20)	Move rate classes to new segments
New Tier 2 rate class • Align growth to cost of growth by consolidating high growth high-density compute customers into a single rate class. • Position HD Compute customers to leverage flexible loads. • Position Grant PUD to respond to legislative impact.	**Reclassify Rate 15 as Tier 1** • After removing HD Compute Rate 15 is no longer fast-growing. **Reclassify Rate 85 as Tier 2** • Reconnecting boiler loads would be load growth.



Recommendation: Large Customer Rate Classes Reorganization

Develop a plan to restructure general service and industrial rate classes	Simplify rate structures
Develop 2027 LPU Proposal • Reduced customers in industrial rates (Rates 14 and 15) after creating the High Density Compute rate (Rate 20). • Large rate classes have similar costs to serve. • Small rate classes have overlap. • Goal: Reduce and simplify rate classes and offerings.	**Develop 2027 Proposal** • Daily format of Residential and General Service rates not compatible with new customer billing system. • General service and Irrigation rate structures very complex. • Goal: Simplify rate structures for customers



2027 Rates Package Timeline

August 2026
Draft Cost-of-Service Analysis

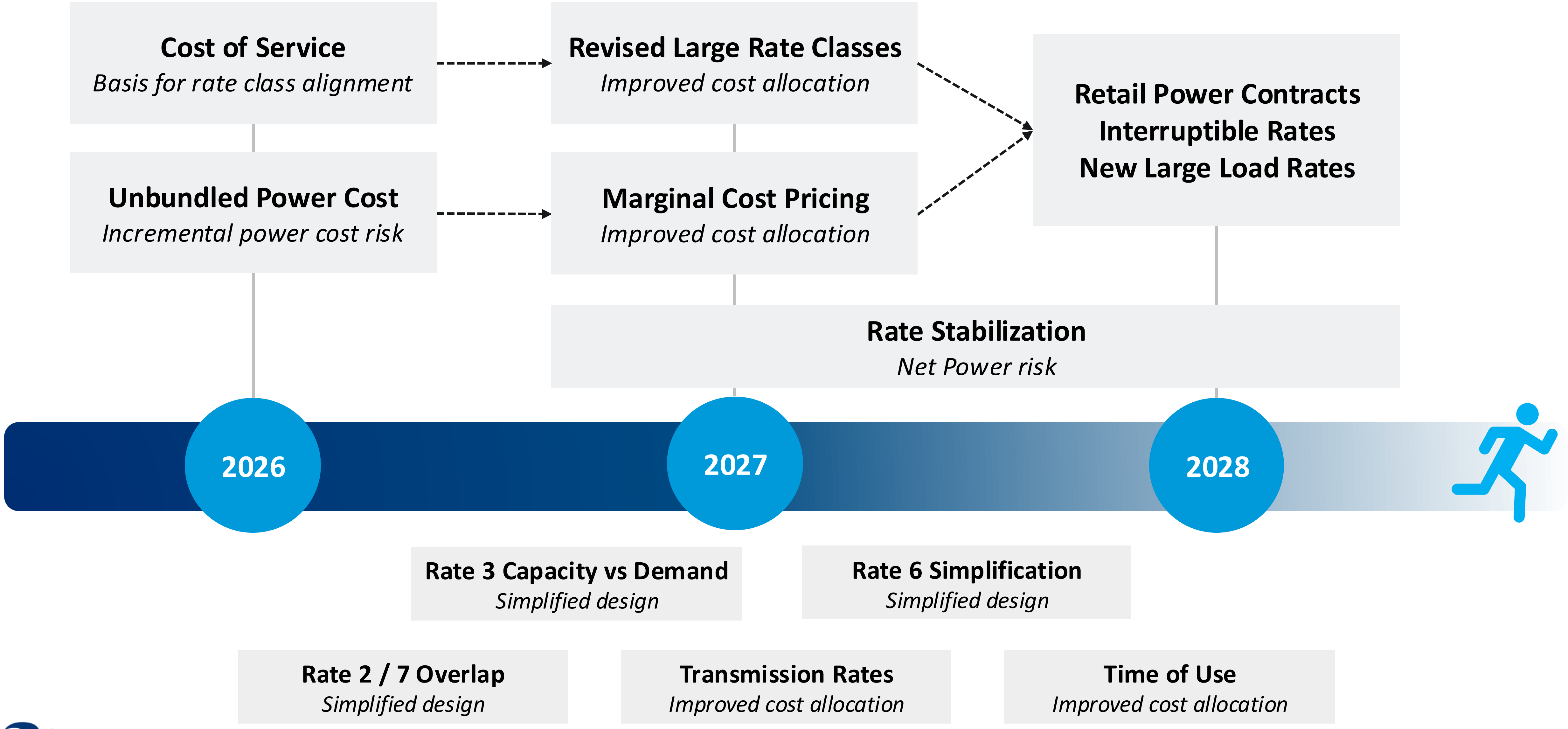
Sept 2026
Final Cost-of-Service Analysis
Draft Rate Trajectory
Draft Rates Package

Oct - Nov 2026
Public Presentation
- Cost of service
- Rate 20 proposal
- Rate Trajectory
- 2027 Rates Package

Dec - Jan 2027
Rates Package Approval

Jun - Aug 2027
Large Customer Reorganization Proposal

Rates Projects and Timeline



System Allocation

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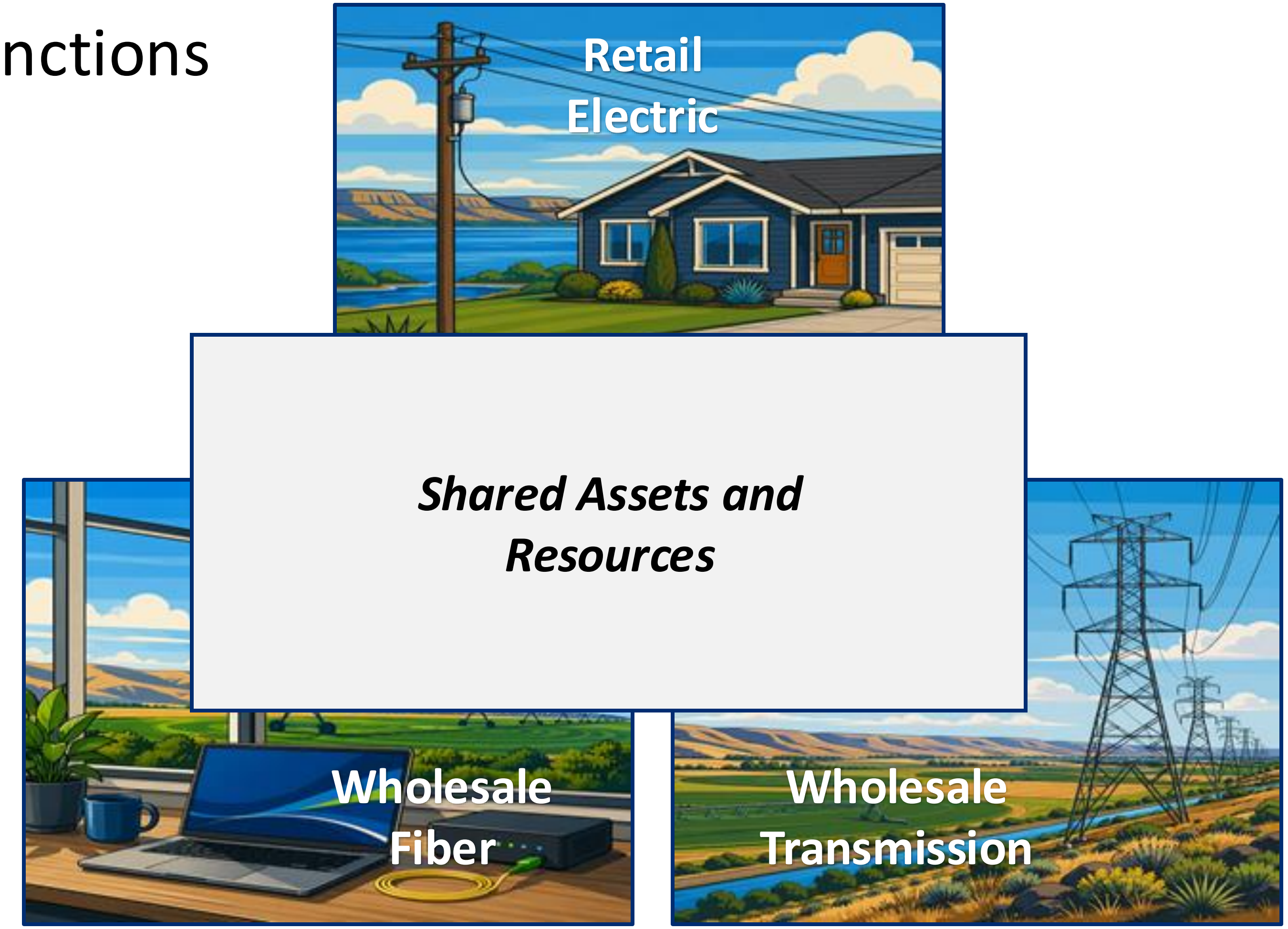
System Allocation

Electric System's three business functions

- Retail Electric
- Wholesale Transmission
- Wholesale Fiber



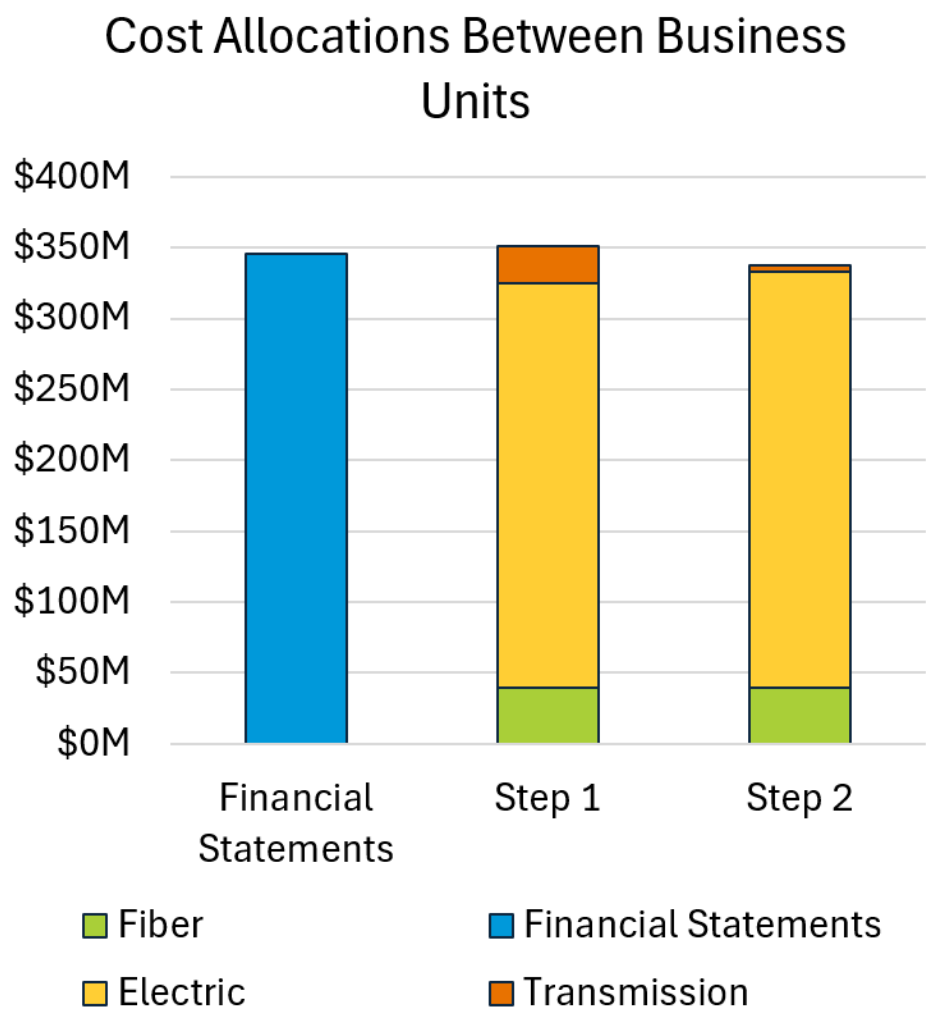
Two Step System Allocation Process

Step 1: Book value, revenues and expenses assigned to each business function

- Function specific resources directly assigned
- Shared resources allocated between the businesses

Step 2: Retail Electric, Wholesale Transmission and Fiber financials created

- Book value, revenues and expenses allocated based on system use



Return On Rate Base

Return on Rate Base	
Asset Cost	$1,324,954,000
Accumulated Depreciation	($630,706,000)
Net Book Value	$694,247,000
Avg Cost of Capital	5.24%
Return on Rate Base	**$36,379,000**

Return on Rate Base

5.24%

Cost of borrowing

Cost of funding capital expenses

Replacement

Cost of replacement at end-of-life including inflation

Investment Tolerance

Foundation for business cases to compare investments

Risk Mitigation

Cushion in the event of early retirement due to catastrophe

Final System Allocations / Income Statement

Surplus wholesale revenues from Electric Retail sufficient to subsidize fiber and transmission business functions

8% of electric system operating expenses allocated to Wholesale Transmission and Fiber

(thousands)	Electric System	Retail Electric	Wholesale Transmission	Wholesale Fiber
Revenues	$593,005	$542,927	$4,408	$16,823
Operating Expenses	$356,333	$269,461	$3,510	$24,999
Non-operating Activity	$60,729	$11,980	$67	($1,279)
Change in Net Position	**297,401**	**$285,446**	**$965**	**($9,454)**
Return on Rate Base	**$50,304**	**$36,379**	**$1,015**	**$12,911**

Allocation Exceptions

- Unused PRP costs assigned to wholesale
- Unrealized gains on investments
- JL Bonds removed from PRP and Non-op
- CIAC depreciation credit replaces CIAC revenues

Retail Electric COSA

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Retail Electric COSA Process

FERC 593: **Overhead Lines** → Function: **Distribution** → Charge Class: **Fixed** → Allocation: **Lines Model** →

- Residential
- General Service
- Irrigation
- Large General
- Industrial
- Large Industrial
- Ag Industrial
- Data Centers

Accounting structure to organize business activities

- Priest Rapids Energy
- Incremental Energy
- Transmission
- Distribution
- Customer Service
- Administration
- Depreciation, Amortization, Taxes, and Non-Operation

- Energy
- Delivery
- Fixed

Evolving Our Power Supply Approach

2023 COSA (2024)

Power supply cost:

- All power costs assigned to rate classes

Non-Operation Credit:

- Net wholesale allocated to rate classes as revenue credit

2026 Cost Allocated Rate Trajectory (2025)

Power supply cost:

- Pay what you use approach

Non-Operation Credit:

- Excess PRP to wholesale
- Net wholesale allocated to district revenue requirement

2025 COSA (2026)

Power supply cost:

- Pay what you use approach
- JLB interest cost removed

Non-Operation Credit:

- JLB benefit removed
- Excess PRP to wholesale
- Net wholesale allocated to district revenue requirement

Significant evolution in power supply cost allocation

Power Supply: Rate Design vs. COSA

Rate Design

- All customers pay the same PRP $/kWh
  - Does not include line loss adjustment
  - Does not include capacity adjustment
- Eliminate tiered rate structure
  - Simplify rate structures
  - Prevent gaming
  - Consistent revenue
  - Incremental includes PRP Credit

Cost-of-Service Analysis

- Different $/kWh values for rate classes
- Analyze energy and capacity cost
  - Energy adjusted by line loss and allocated by volume
  - Capacity adjusted by line loss and allocated by WRAP month peak load

Neither approach is better

Each approach accomplishes a different task

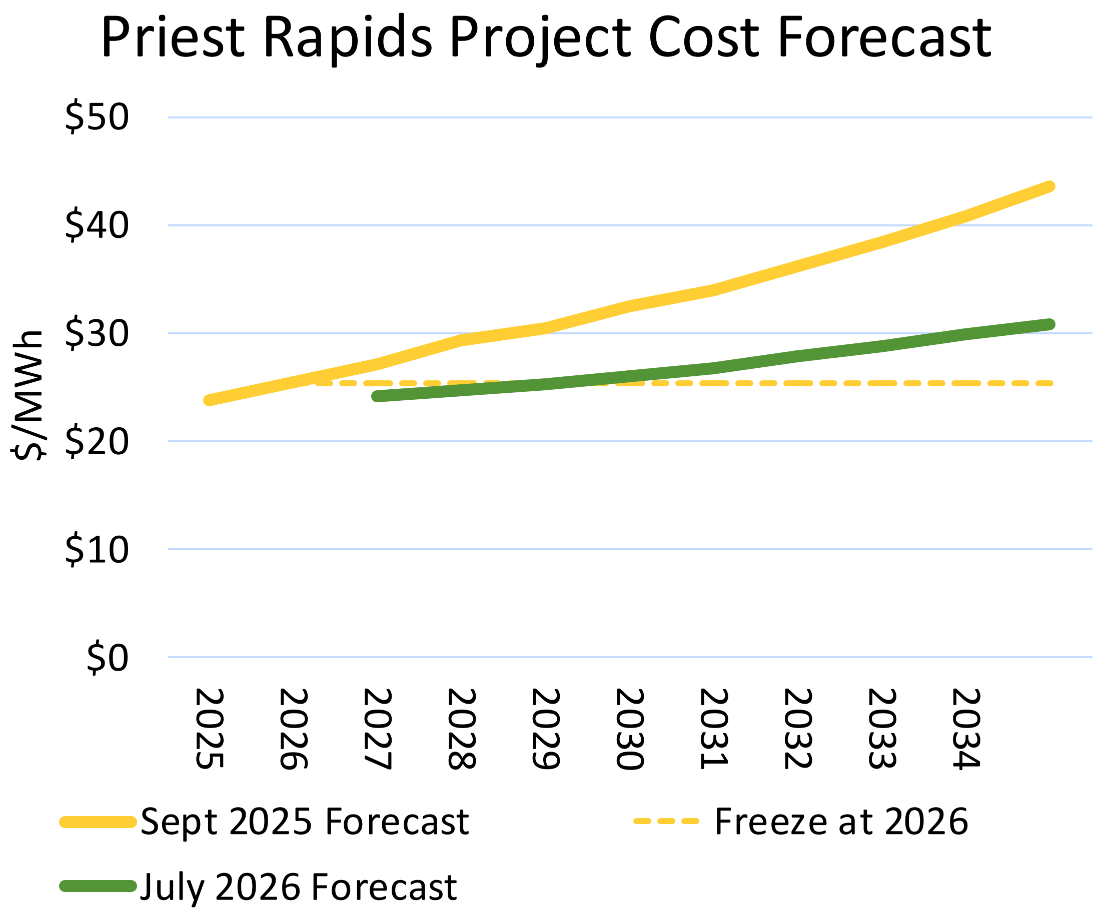
Priest Rapids Project Costs Have Changed

Priest Rapids Project costs on bill

- Modeling changes mean PRP costs will likely be lower until 2028 or 2029
- Offset by lower non-operation benefits
- Overall costs have not decreased

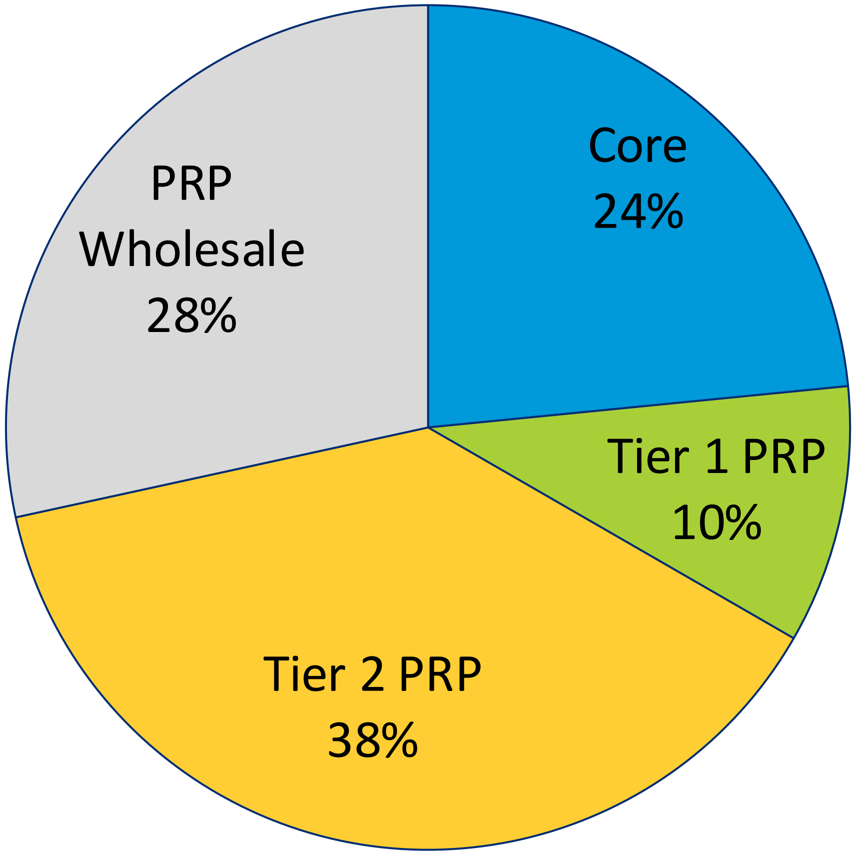
Options

- Reduce PRP and increase delivery
- Hold PRP steady until costs catch up



Priest Rapids Project Power Supply Allocation

$158.6M Priest Rapids Project allocation



Priest Rapids Project Costs allocated by share of MWh load

- 6,157,980 MWh assigned to Core, Tier 1, and Tier 2
- Remaining 2,444,420 MWh assigned to wholesale

$/MWh the same for all rate classes

- $113.6M allocated to rate classes
- Remaining $45.09M assigned to wholesale

Separate energy and capacity dollars (COSA Only)

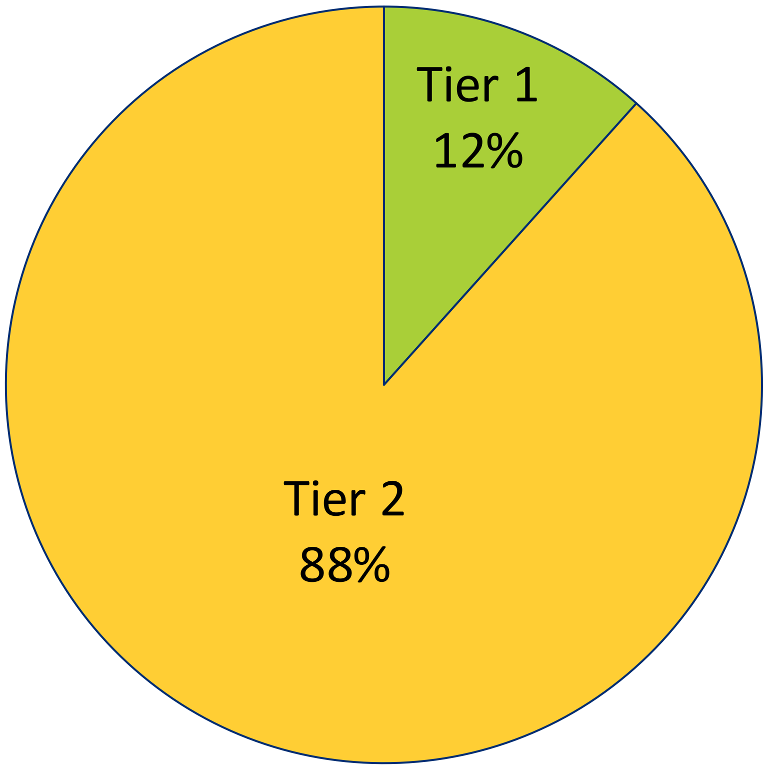
- 36% of dollars assigned to energy
- 64% of dollars assigned to capacity

Allocate to rate classes (COSA Only)

- Energy allocated by rate class share of MWh
- Capacity allocated by rate class share of WRAP coincident peak
- Shifts some costs between Core and Tier 1 / Tier 2 due to line losses and peak capacity

Incremental Power Supply Allocation

$15.45M Incremental Power allocation



Share of growth determines incremental MWh to recover

- 30,755 MWh assigned to Tier 1 (12% of forecast growth)
- 233,501 MWh assigned to Tier 2 (88% of forecast growth)

Rank order resources by cost and allocate to Tier 1 / Tier 2

- $1.39M assigned to Tier 1 (receives access to lowest cost resources)
- $14.06M assigned to Tier 2 (remaining high-cost resources)

Separate energy and capacity dollars (COSA Only)

- 44% of dollars assigned to energy
- 56% of dollars assigned to capacity

Allocate to Tier 1 and Tier 2 Segments

- Energy allocated by rate class share of MWh
- Capacity allocated by rate class share of WRAP coincident peak

Calculate PRP Credit (Rates Only)

- Avoids double counting from for billing all kWh at the same PRP and Tier Incremental cost

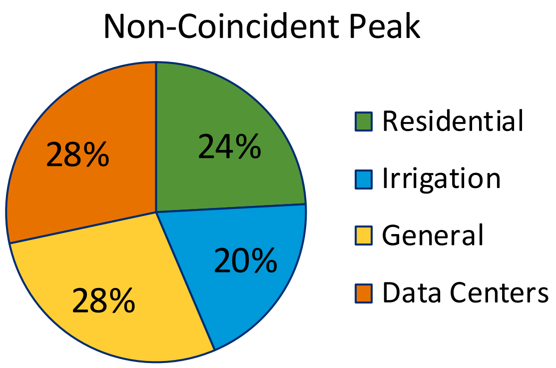
Power Delivery

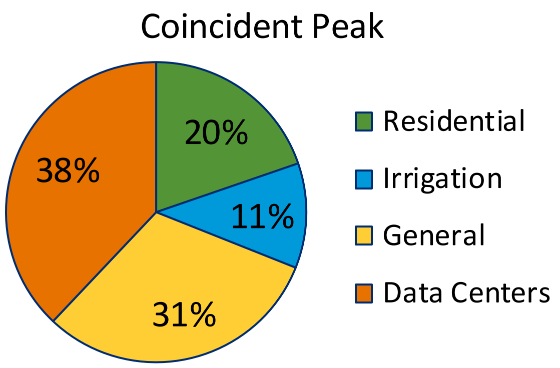
Higher for Residential and Irrigation

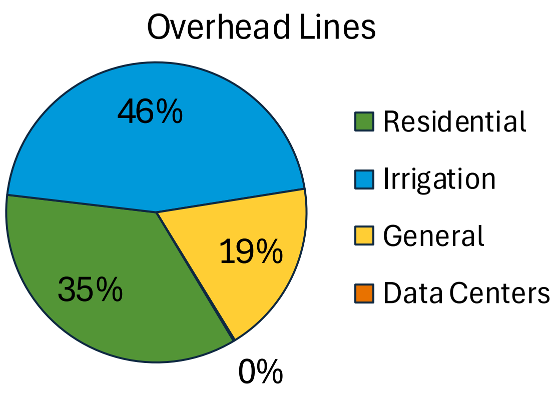
- Require the most line miles to serve
- Lower load factors requiring excess capacity build to meet peaks

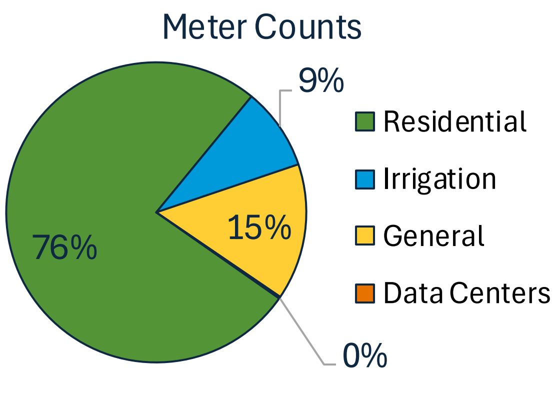
Lower for Tier 1 and Tier 2 classes

- Closer proximity to substations
- Higher load factors which are less expensive to serve









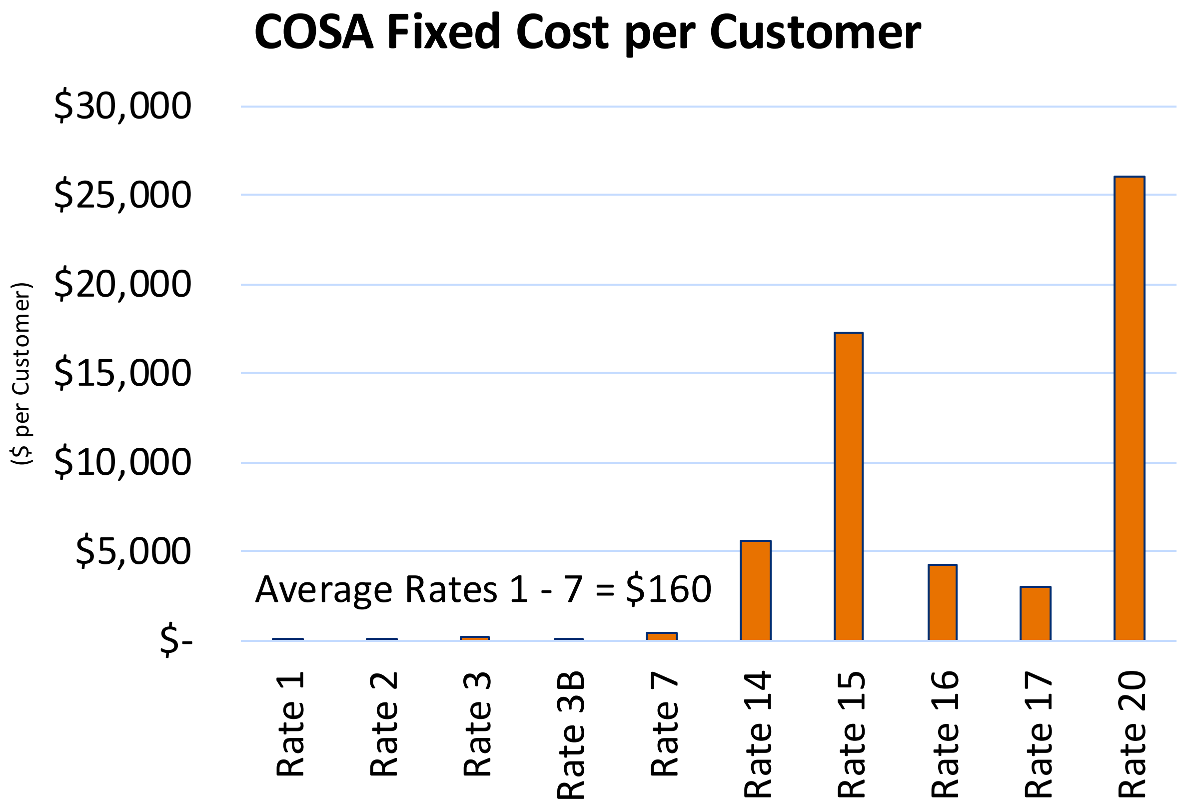
Customer Service & Administration

Customer Service costs highly variable between rate classes

- Tier 2 more expensive to serve on a per customer basis
  - Time intensive to manage accounts
  - Lower volume of customers

Administrative costs tend to be fixed and shared equally

- Overhead and other shared costs (IT, HR, Finance, etc.)
- Primarily allocated based on revenues or usage



Non-Operation Costs and Credits

Non-operating activity includes revenues and expenses

- Taxes
- Interest earnings & expense
- Depreciation on General & Intangible plant
- Customer service charges

Allocated to rate classes based on proportionate share of costs directly allocated to fixed and delivery charges

Results

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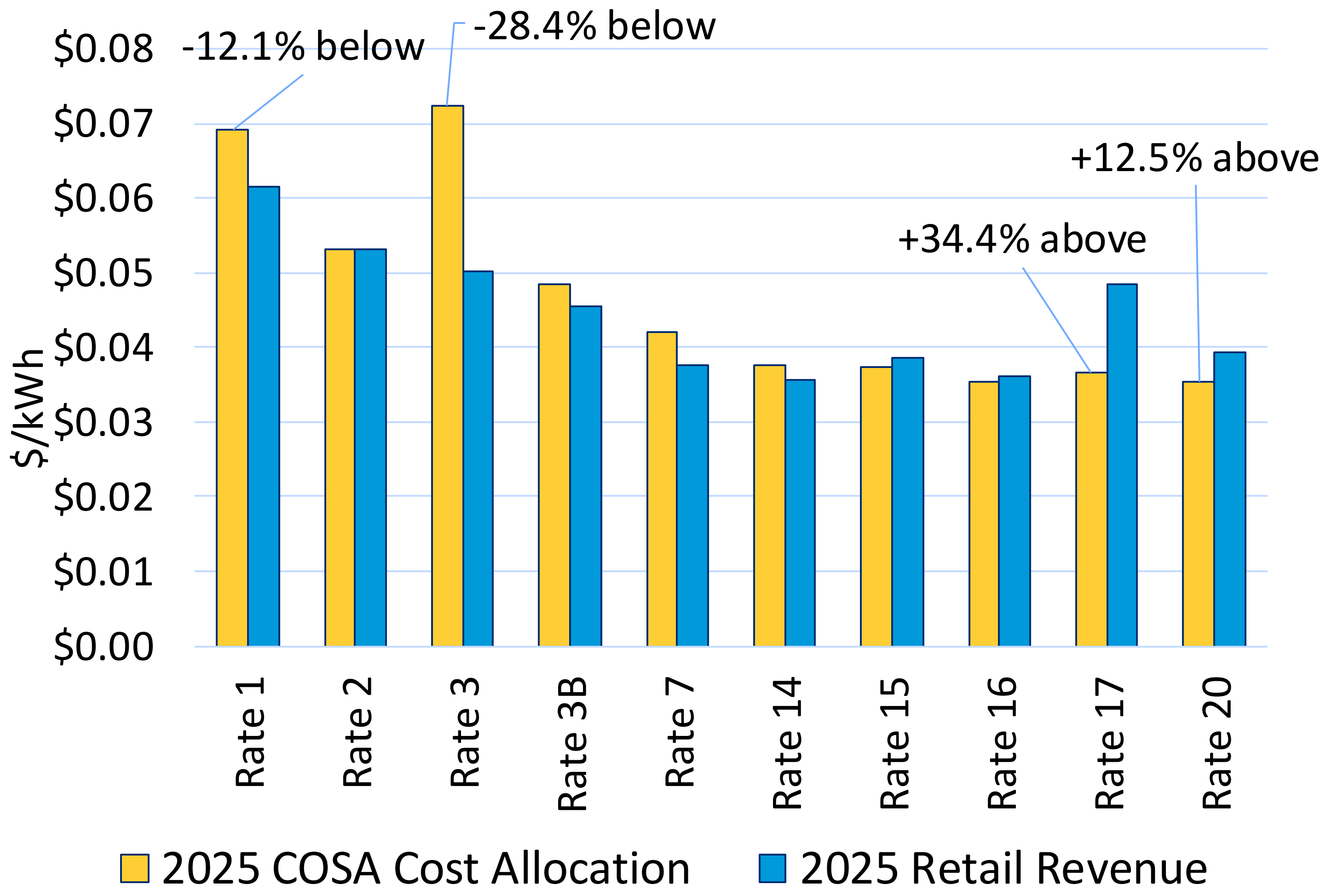
COSA – Revenue

COSA-Revenue perspective compares the cost to serve vs. retail revenue

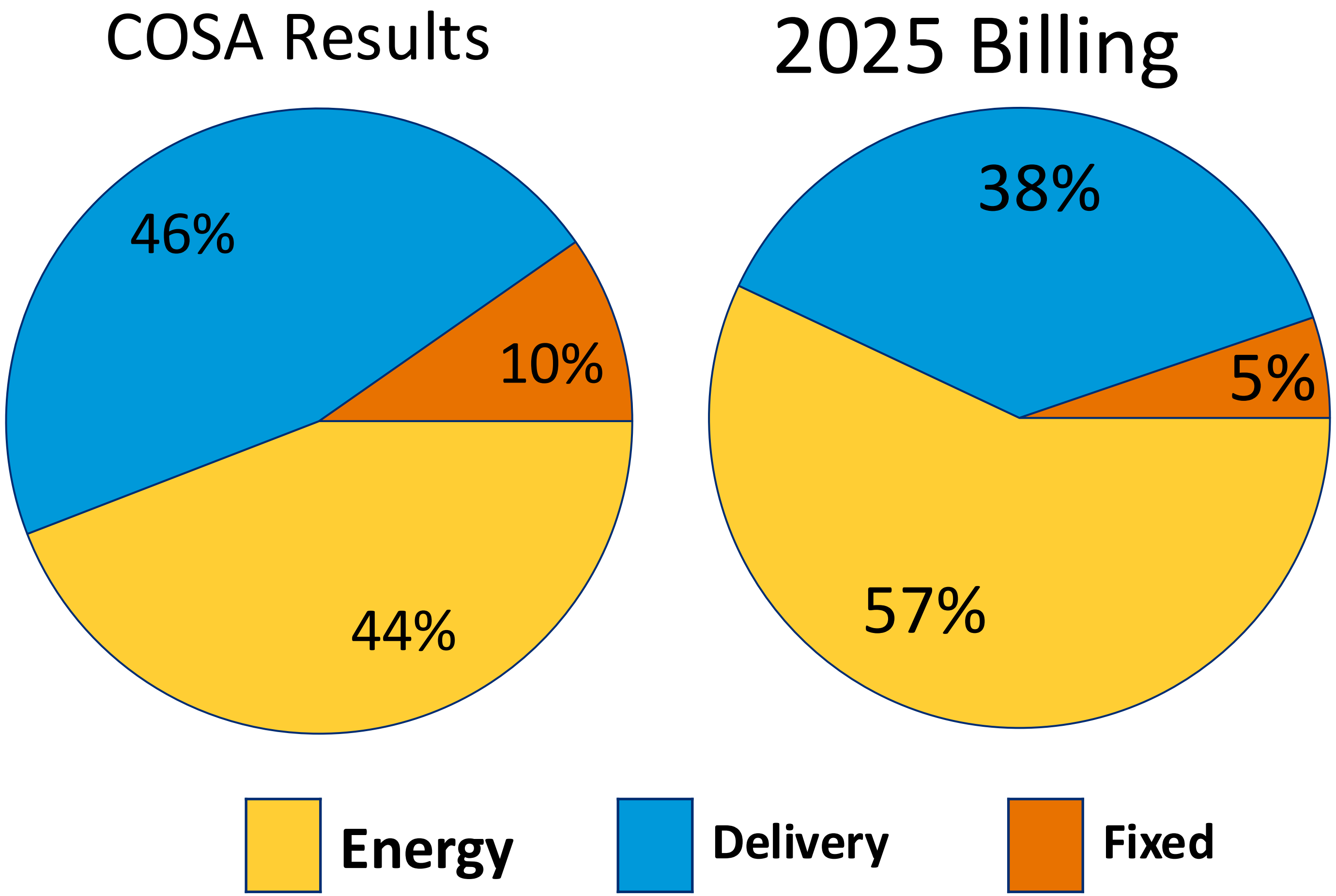


Key Learnings

- Rate 1 (Residential) and Rate 3 (Irrigation) pay below their cost of service.
- Rate 17 and Rate 20 (Tier 2 – Evolving Industry and High-Density Compute) pay above their cost of service.
- Rate 2 and 3B (Core – General Service and Ag Service) are above cost of service but small customers pay below cost of service.

Charges

Charges perspective compares current rate structure to a pure COSA rate structure

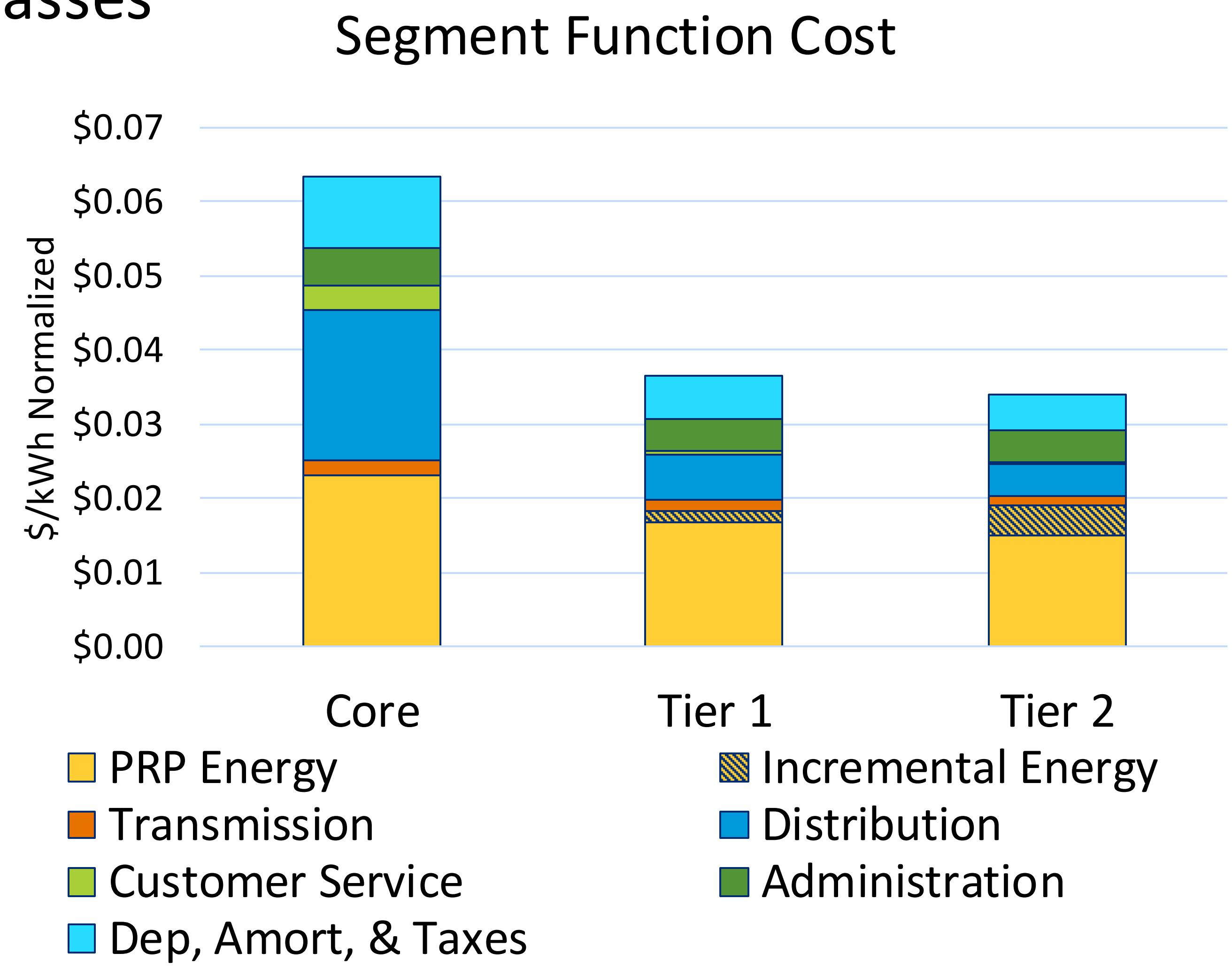


Key Learnings

- Most rate structures over-allocate energy and under-allocate delivery.
- Industrial rate structures have fixed charges much lower than cost to serve.
- No immediate risks identified – but if load profiles significantly change or delivery only customers increase the utility would not fully recover costs.

Functions

Function perspective explores the cost to provide specific services to rate classes



Key Learnings

- Line losses and peak nature of Core Loads largely offset preferential access to Priest Rapids Project power in the COSA.
- Core customers incur much higher distribution, customer service, and depreciation costs compared to their Tier 1 and Tier 2 counterparts.

Outlier Results

Key Points

- Rates 6, 19, and 85 are outliers due to limited customers and energy use.
- Outlier rate classes have artificially low cost to serve estimates.
- Low short term financial risk.

Rate 6 – Streetlighting

- Staff concerned some costs not allocated correctly
- Unique evening only load profile
- 0.08% of Grant PUD load

Rate 19 – EV Charging

- Low load factor challenges allocation model
- 0.04% of Grant PUD load

Rate 85 – Ag. Boiler

- No boiler load in 2025; no load forecasted
- Zero load creates artificially low COSA results
- Significant stranded assets

Recommendations

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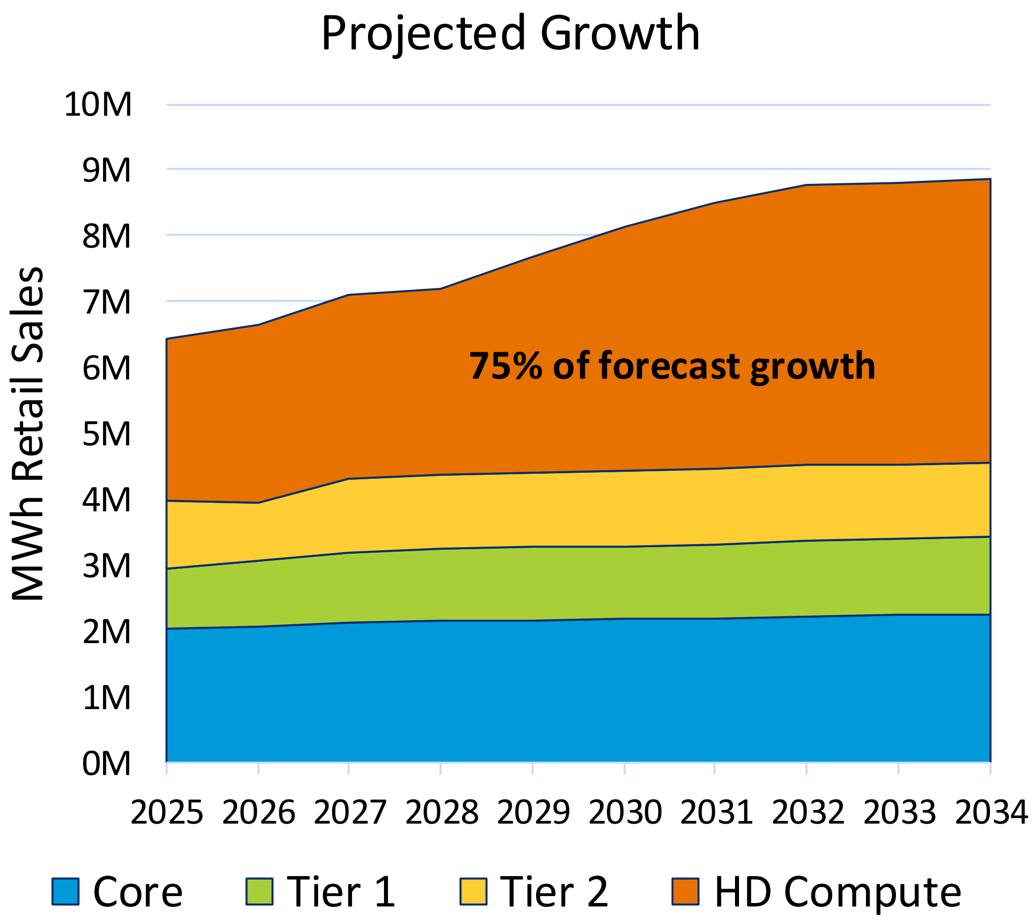
Recommendation:
Align Customers with Growth

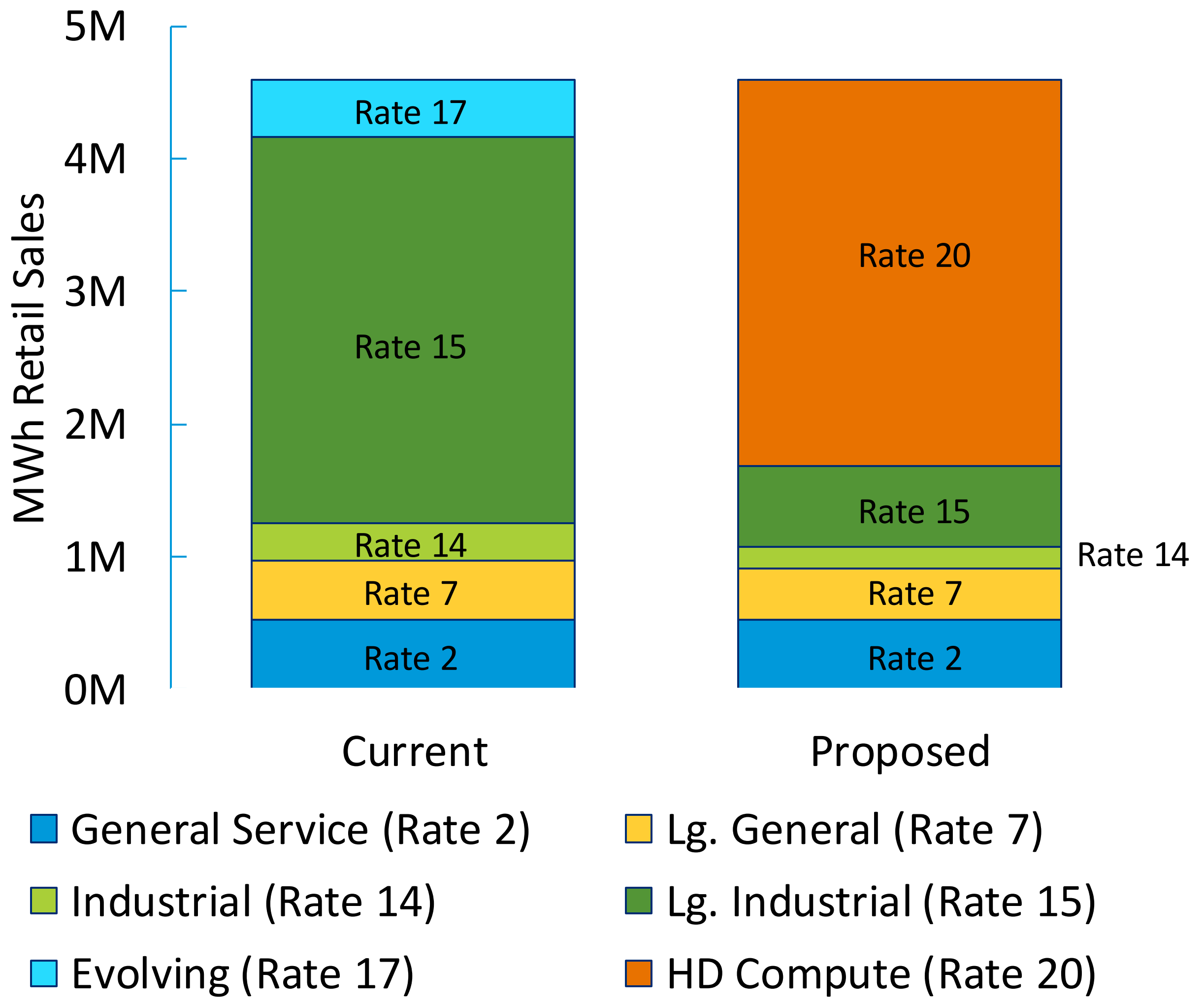
Create a new High-Density Compute rate (Rate 20)	Move rate classes to new segments
New Tier 2 rate class • Align growth to cost of growth by consolidating high growth high-density compute customers into a single rate class. • Position HD Compute customers to leverage flexible loads. • Position Grant PUD to respond to legislative impact.	**Reclassify Rate 15 as Tier 1** • After removing HD Compute Rate 15 is no longer fast-growing. **Reclassify Rate 85 as Tier 2** • Reconnecting boiler loads would be load growth.



Create New High-Density Compute Rate (Rate 20)

Plan to Implement Rate 20

1. Create new High Density Compute rate class
2. Removing Evolving Industry status from Crypto mining customers
3. Move High-Density Compute customers
   - General Service (Rate 7)
   - Industrial (Rate 14)
   - Large Industrial (Rate 15)
   - Evolving Industries (Rate 17)



Recommendation:
Reorganization of Large Customer Rate Classes

Explore options to restructure general service and industrial rate classes	Explore options to simplify rate structures for ERP solution
Develop 2027 Large Power Customer Proposal • Reduced customers in industrial rates (Rates 14 and 15) after creating the High-Density Compute rate (Rate 20). • Large rate classes have similar costs to serve. • Small rate classes have overlap. • **Goal: Reduce and simplify rate classes**	**Develop options to simplify 2028 rates** • Daily structure of Residential and General Service basic charge not compatible with new customer billing system. • General service and Irrigation rate structures very complex. • **Goal: Simplify rate structures for customers**

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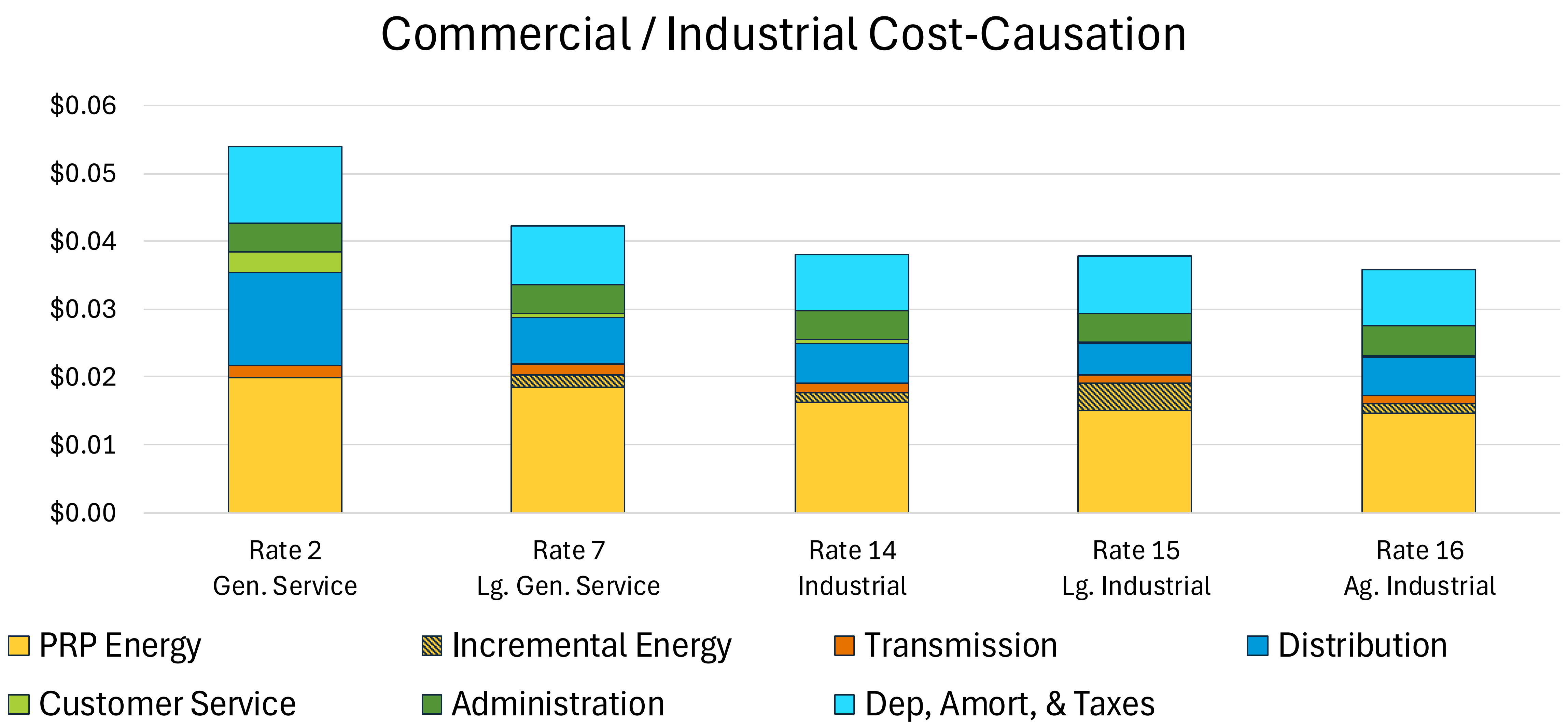
Cost-to-Serve: Large Customer Rate Classes



Consider Simplifying Rate Structures

Current Rate Structure

Rate	Residential	General (R2)	Irrigation	Large Industrial
Basic Charge	• Daily	• Daily • Varies by phase	• Select months • Varies by phase	• Monthly
Energy	• kWh * rate	• kWh * rate	• kWh * rate	• kWh * rate
Delivery	• kWh * rate	• kWh * rate	• kWh * rate • HP * Inclining block • Select months	• kW * rate
Minimum	• Flat	• kW * rate minimum		• Demand ratchet

Least Complicated ← **Most Complicated** → **Less Complicated**

Observations

- General Service and Irrigation rates are much more complicated than larger rate classes and opportunities be simplified.
- Ease implementation of new billing system.
- Simplify customer service.

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Consider Increasing Large Customer Fixed Charges

Increase revenue stability

1. Consider a significant rate increase to fixed charges in 2027 as part of planned Tier 1 and Tier 2 rate increases
2. Consider impact to small customers, especially new Rate 20 customers
3. Rates & Pricing proposal will consider how demand ratchet mitigates risk.

Rate	Current Monthly $	COSA Monthly $	% Bill Change	Current Billing $
Rate 7 Lg. General Service	$166.63	$459.61	+3.63%	$8,100
Rate 14 Industrial	$726.44	$5,530.83	+4.00%	$121,000
Rate 15 Large Industrial	$1,061.08	$17,260.63	+3.60%	$449,200
Rate 16 Ag Industrial	$726.44	$4,230.02	+4.33%	$81,370
Rate 17 Evolving Industry	$1,000.00	$3,038.56	+2.72%	$74,830
Rate 20 HD Compute	$1,061.08	$26,076.17	+5.09%	$490,320

What Rates & Pricing is Exploring for 2027

Alternative structure

- Small Business: Up to 50 - 100kW
- Commercial: Small business to 500kW - 2MW
- Industrial: Larger than Commercial

Inclining block demand

- Reduce need for additional rate classes
- Eliminate phase specifications
- Simplify irrigation rates

Future Research

- Electric utility rate structures
- Obvious break points
- Impact on customer bills
- Internal alignment
- Commission feedback

2027 Rates Package Timeline

August 2026

Draft Cost-of-Service Analysis

Sept 2026

Final Cost-of-Service Analysis

Draft Rate Trajectory

Draft Rates Package

Oct - Nov 2026

<u>Public Presentation</u>

- Cost of service
- Rate 20 proposal
- Rate Trajectory
- 2027 Rates Package

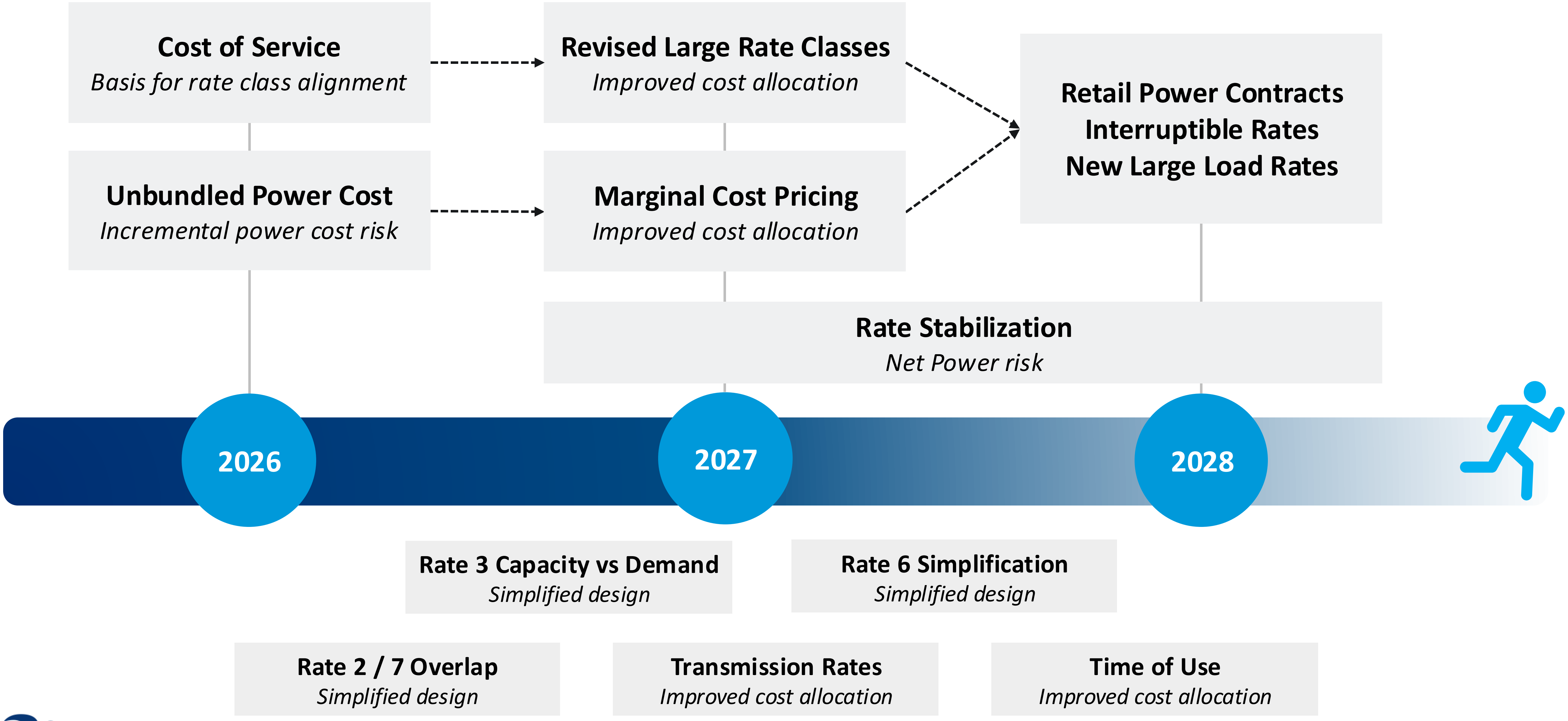
Dec - Jan 2027

Rates Package Approval

Jun - Aug 2027

Large Customer Reorganization Proposal

Rates Projects and Timeline



Thank you!

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APPENDIX

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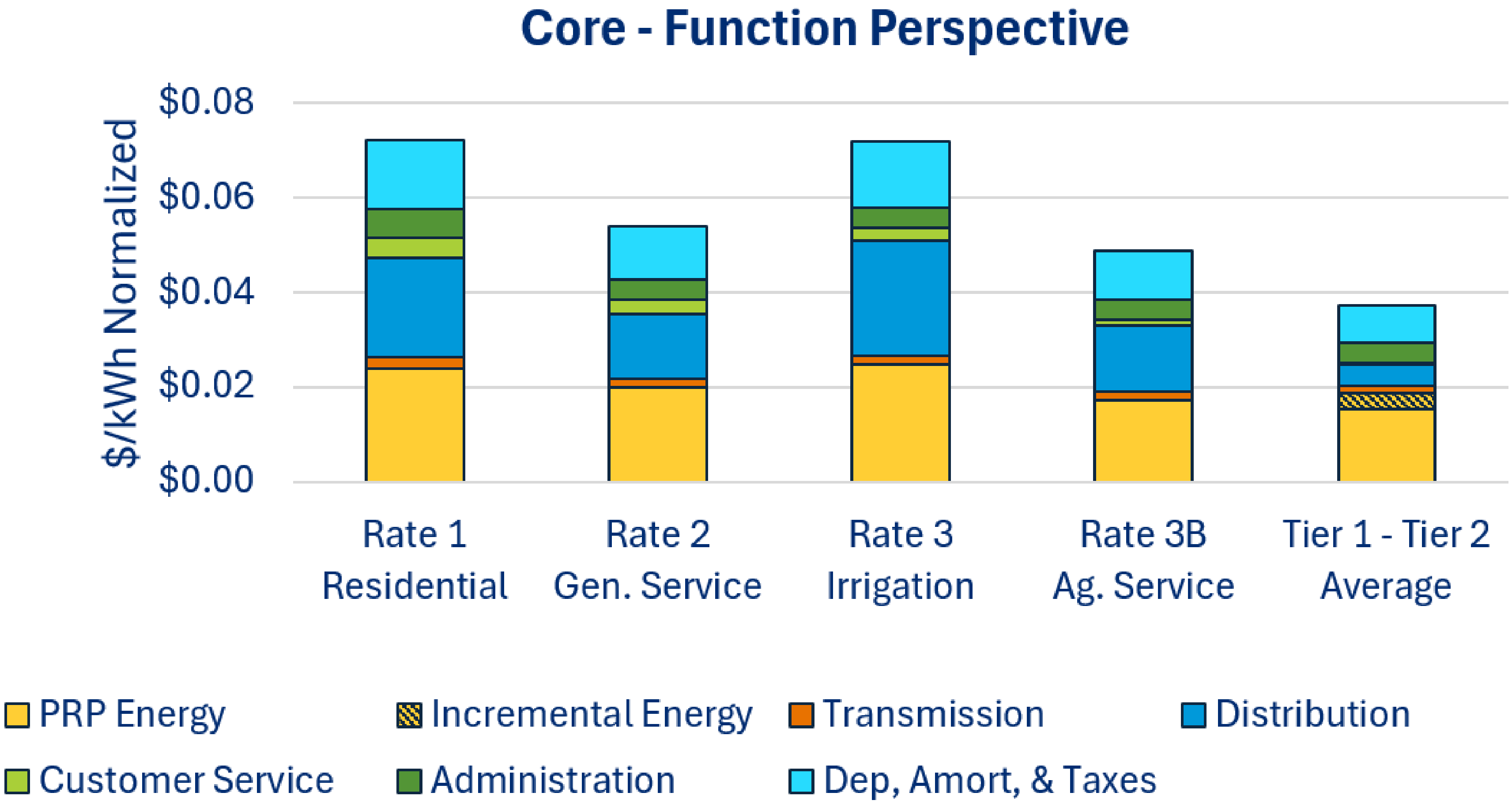
Core Function

Observations

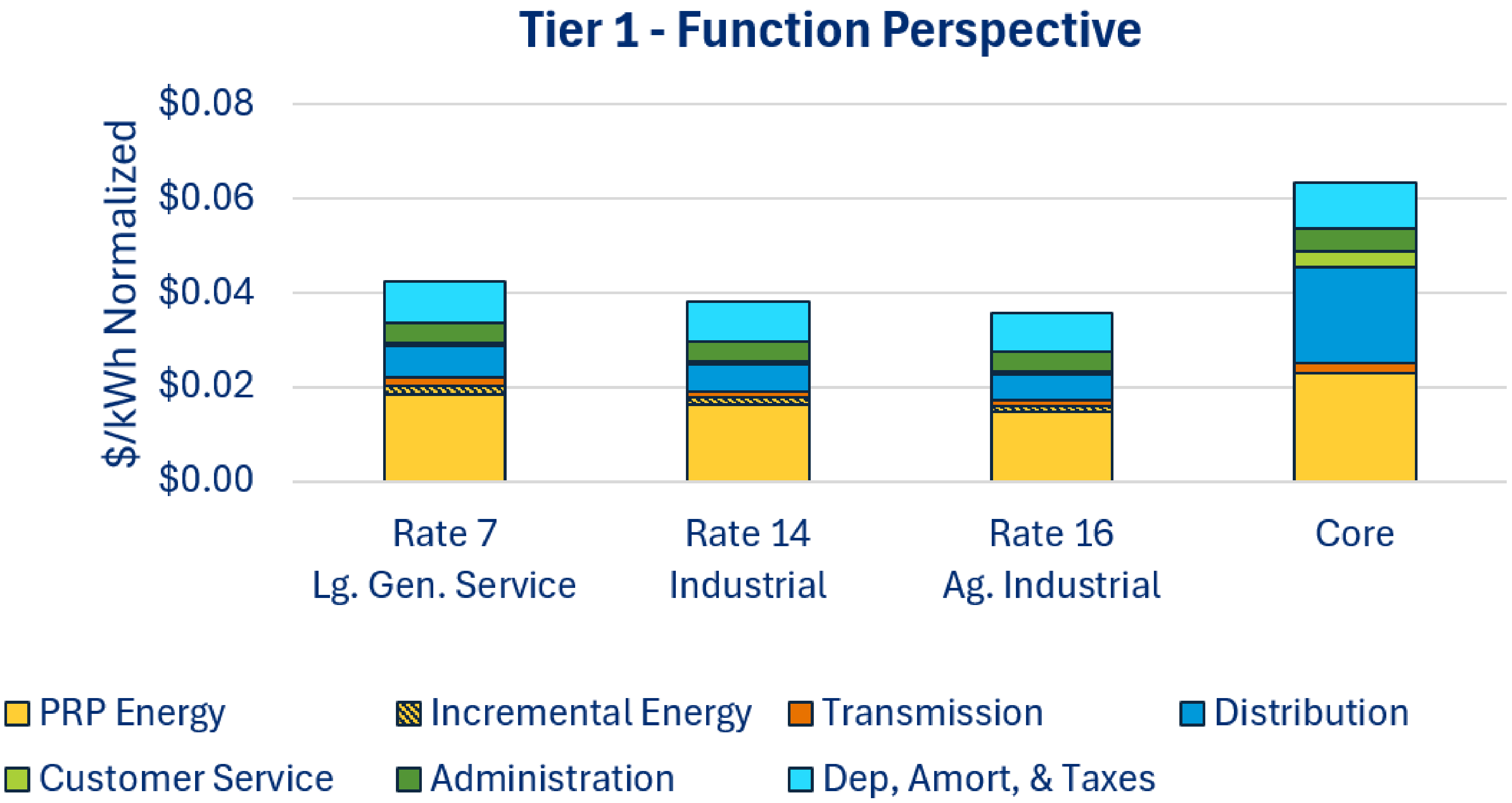
- **Power Supply**: Line losses and capacity differences allocate more costs to Core vs. non-Core resulting in higher overall costs.
- **Power Delivery:** Core rate classes incur higher power delivery costs due to line miles and low load factors.
- **Customer Service + Admin**: Core customer classes incur significantly higher customer service and administrative costs due to volume of customers.



Tier 1 Function

Observations

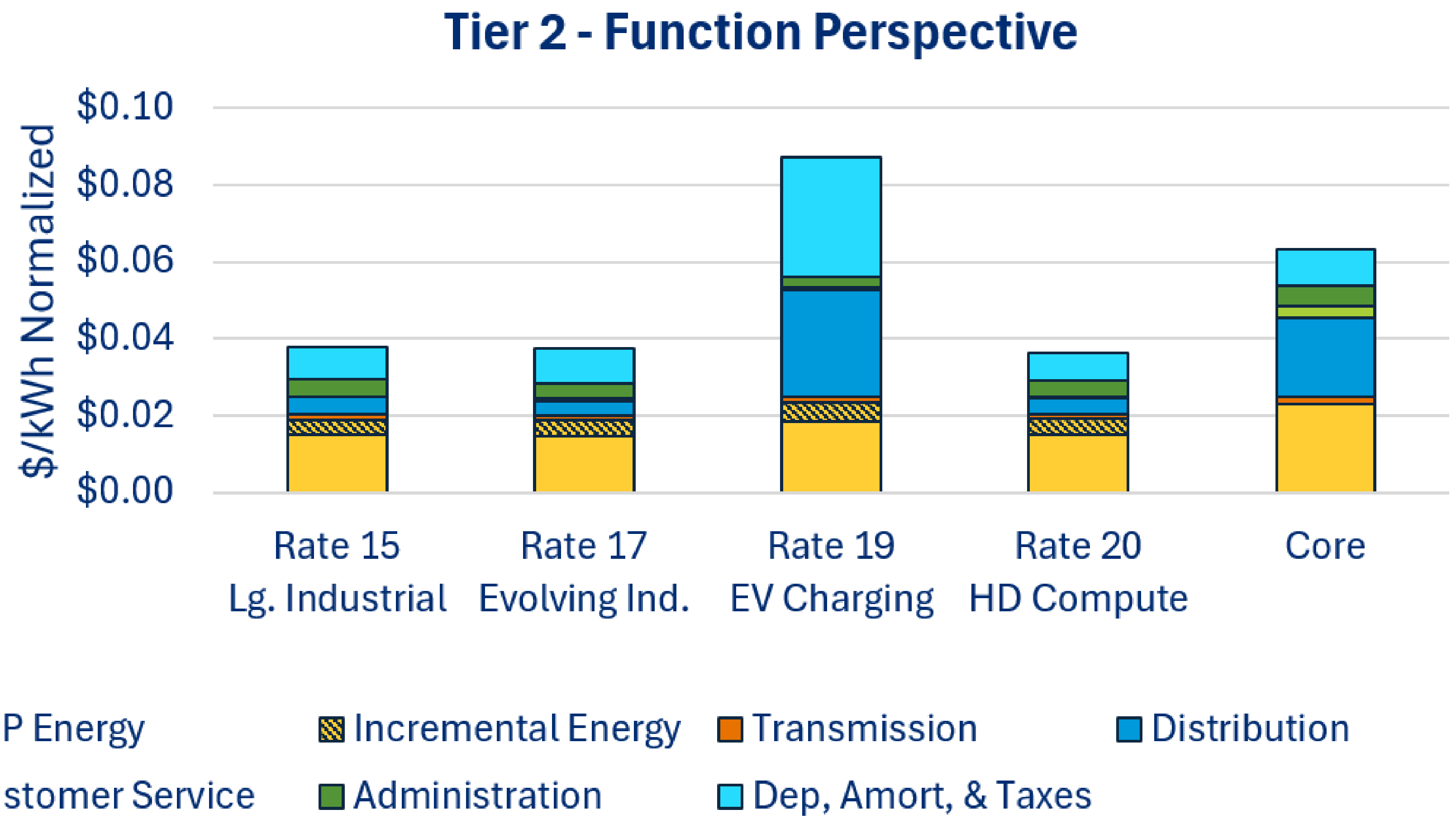
- **Power Supply**: Power Supply Charge is consistent among tier 1 rate classes
- **Power Delivery:** Tier 1 rate classes incur lower Power Delivery costs because they are generally located in more concentrated service areas, requiring less distribution infrastructure per unit of load.
- **Customer Service + Admin**: Tier 1 customers incur substantially lower Customer Service and Administrative costs due to lower customer volumes and reduced service demands.



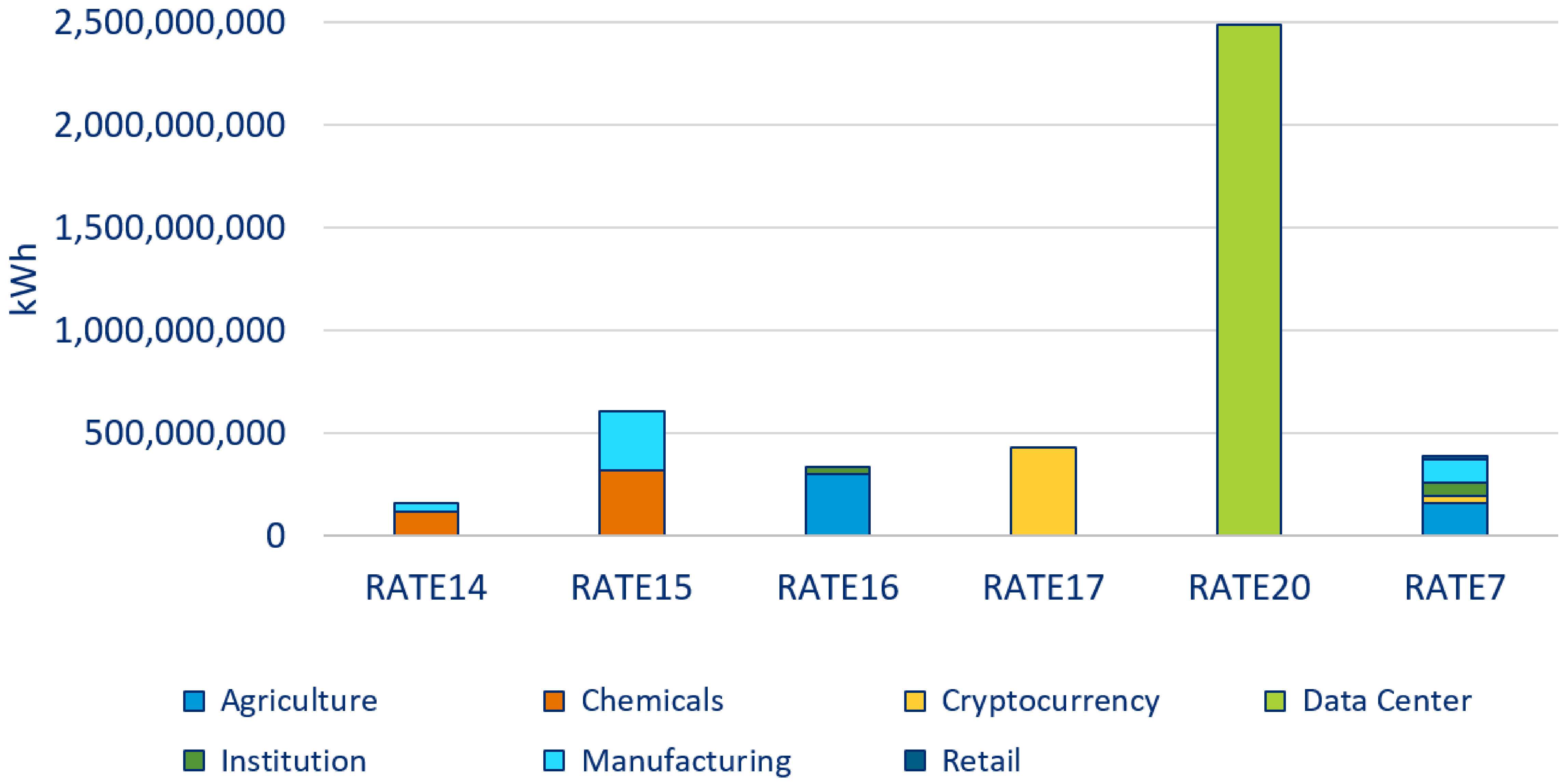
Tier 2 Function

Observations

- **Power Supply**: Power Supply costs are generally lower for Tier 2 rate classes due to lower line losses and coincident peaking during WRAP months despite paying incremental power cost.
- **Power Delivery:** Most Tier 2 rate classes have low Power Delivery costs due to large size, geographic concentration, and high load factor.
- **Customer Service + Admin**: Tier 2 rate classes incur substantially lower total Customer Service + Admin costs due to low customer count.



Industries Energy Usage by Rate Class



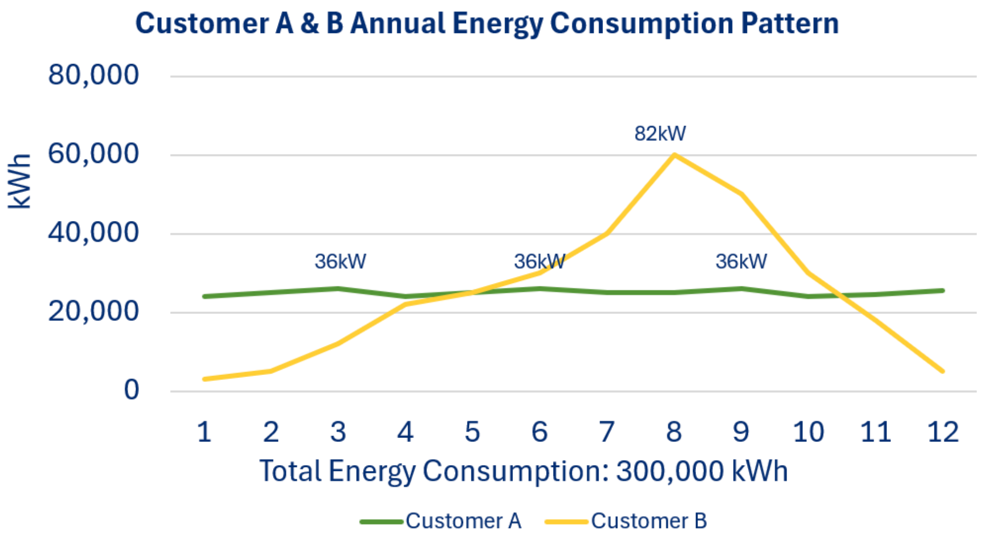
Load Factor Impacts Rate Design

Load factor is the ratio of average load to peak demand over a specific period, indicating the efficiency of utility infrastructure.

- Formula: $\text{Load Factor} = \dfrac{\text{Average Load}}{\text{Peak Demand}} = \dfrac{\text{kWh}}{\text{Peak kW X Hours}}$

Higher load factor customer will have lower charge; lower load factor customer will have a higher charge.

- Customer A LF: 96%
- Customer B LF: 42%

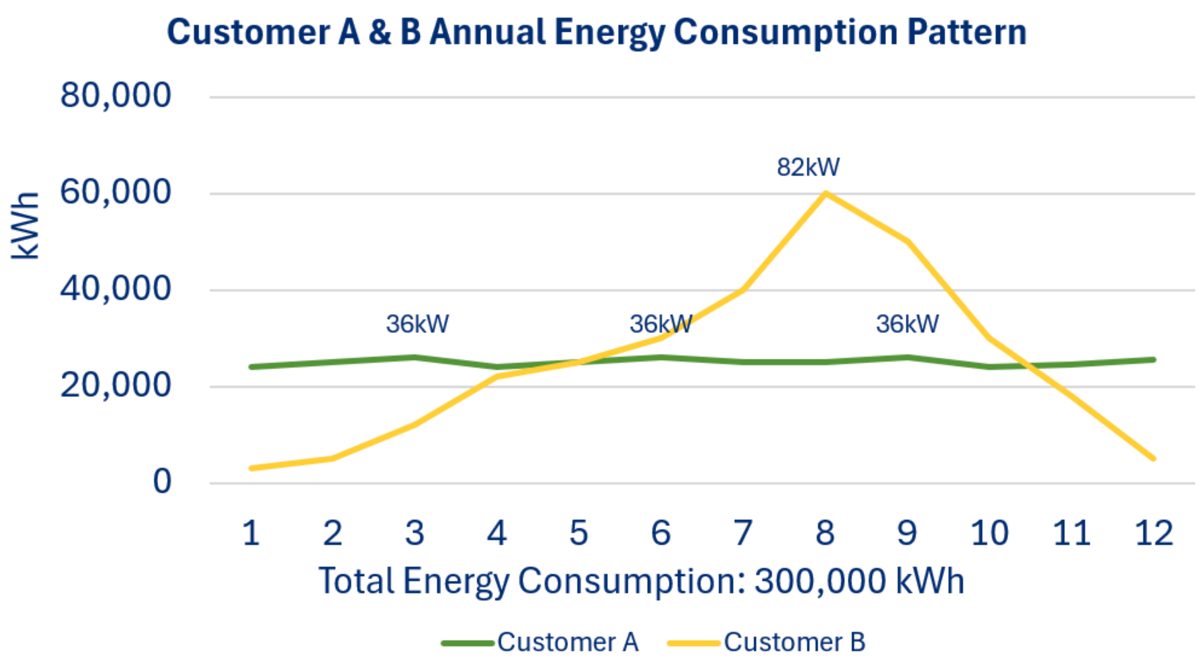


- Demand based on kW is a more accurate and fairer way to recover delivery cost.
- Most Residential, General Service, and Irrigation customers have average load factors between 13% and 21%.
- Industrial customers range between 35% and 65%. Data centers range between 50% and 90%. EV charging averages 6%.
- Rate classes above 5MW feature a “demand ratchet” where the peak demand sets minimum bill.

Load Factor Impacts Rate Design

Customer A – High Load Factor

Month	1	2	3	4	5	6	7	8	9	10	11	12	Sum
kWh (Monthly Energy Consumption)	24,000	25,000	26,000	24,000	25,000	26,000	25,000	25,000	26,000	24,000	24,500	25,000	300,000
Energy Consumption Hours (8760 hrs/12 months)	730	730	730	730	730	730	730	730	730	730	730	730	8,760
kW (Monthly Demand kW=kWh/hrs)	33	34	**36**	33	34	**36**	34	34	**36**	33	34	35	



Customer A:

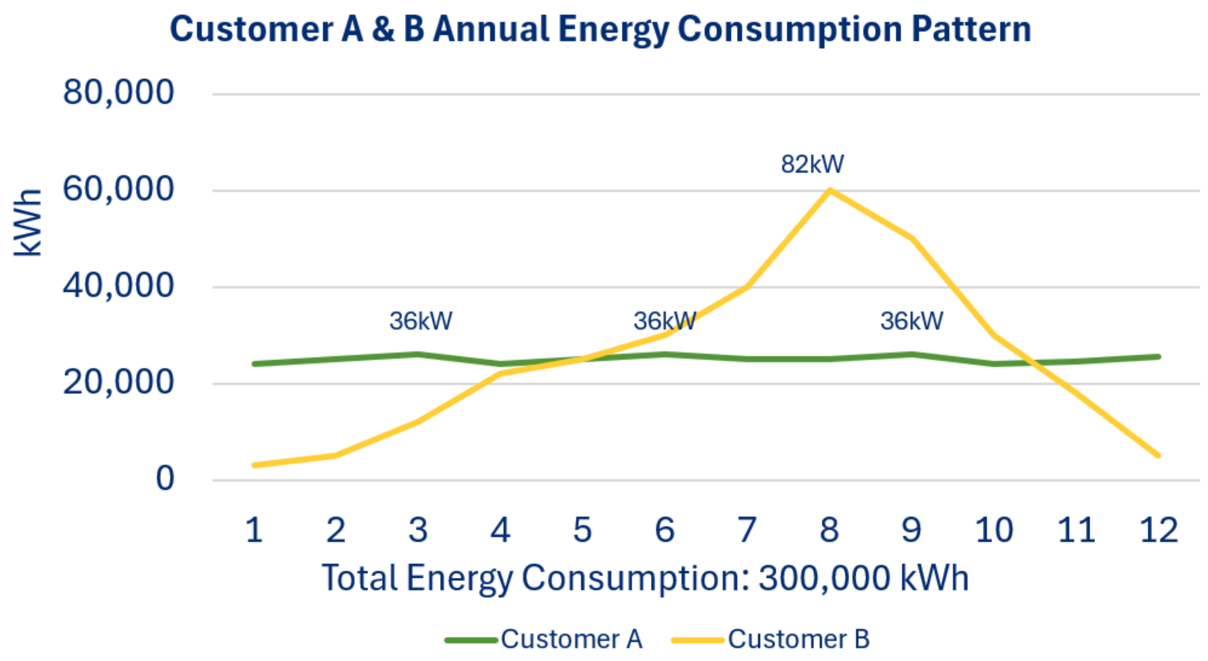
- **Energy Consumption: 300,000 kWh**
- **Peak Demand: 36 kW**
- **Load Factor = Annual kWh/Peak Demand x Total Hours**

  = 300,000/36kW x 8760 hours = 96%
- **Consuming same kWh energy, the higher load factor customer, will have a lower peak demand, which means they require less infrastructure to be served, thus will have a lower demand charge (Delivery Charge)**
- Billing Charge=Energy Charge (Same)+Delivery Charge(Lower)+Fixed Charge(Same)

Load Factor Impacts Rate Design

Customer B – Low Load Factor

Month	1	2	3	4	5	6	7	8	9	10	11	12	Sum
kWh (Monthly Energy Consumption)	3,000	5,000	12,000	22,000	25,000	30,000	40,000	60,000	50,000	30,000	18,000	5,000	300,000
Energy Consumption Hours (8760 hrs/12 months)	730	730	730	730	730	730	730	730	730	730	730	730	8,760
kW (Monthly Demand kW=kWh/hrs)	4	7	16	30	34	41	55	**82**	68	41	25	7	

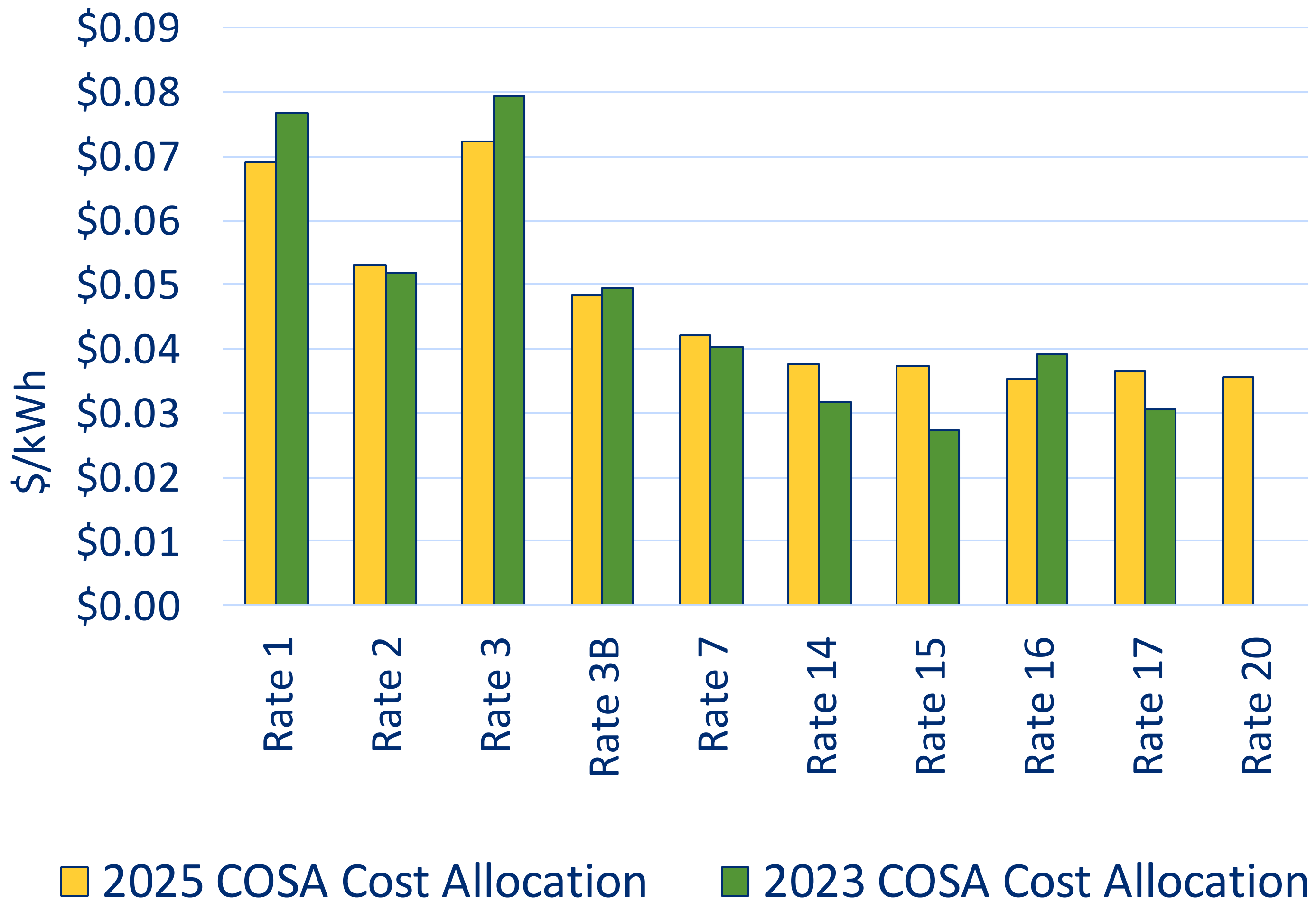


Customer B:

- **Energy Consumption: 300,000 kWh**
- **Peak Demand: 82 kW**
- **Load Factor = Annual kWh/Peak Demand x Total Hours**

  = 300,000/82kW x 8760 hours = 42%
- **Consuming same kWh energy, the lower load factor customer, will have a lower peak demand, which means they require more infrastructure to be served, thus will have a higher demand charge (Delivery Charge)**
- Billing Charge=Energy Charge (Same)+Delivery Charge(Higher)+Fixed Charge(Same)

2023 vs. 2025 COSA – Revenue



Key Learnings

- $67.5M of power costs not assigned to rate class allocation.
  - $45M PRP assigned to wholesale
  - $22.5M PRP JLB
- Power Supply allocations account for 87% of the difference between the 2023 COSA and 2025 COSA.
- The 2025 COSA allocated fewer costs to Core and more costs to Tier 1 and Tier 2 customers – mostly due to power supply.

Delivery: Rate Design vs. COSA

Rate Design

- Small customers pay kWh delivery
    - Easier for customers to understand
    - Low demand with little control
    - Low load factor is common
- Large customers pay kW delivery
    - Sophisticated customers with control
    - Business drives load factor
    - Diversity of load factors
    - Low load factor = expensive to serve

Cost-of-Service Analysis

- All costs normalized to $/kWh
    - Common comparison denominator

Neither approach is better

Each approach accomplishes a different task

Delivery charges vs. Fixed charges

Delivery

- Cost to serve customers *within* rate classes vary based on use (size matters)
- Most Power Delivery costs
  - Transformers
  - Stations
- Some customer service and admin costs
  - Property insurance
- Bill based on volume or demand

Fixed

- Cost to serve customers *within* rate classes *theoretically* the same
- Some Power Delivery costs
  - Lines
- Most customer service and admin costs
  - Records and collection
  - Customer assistance
- All customers pay the same

Each approach meets a different need

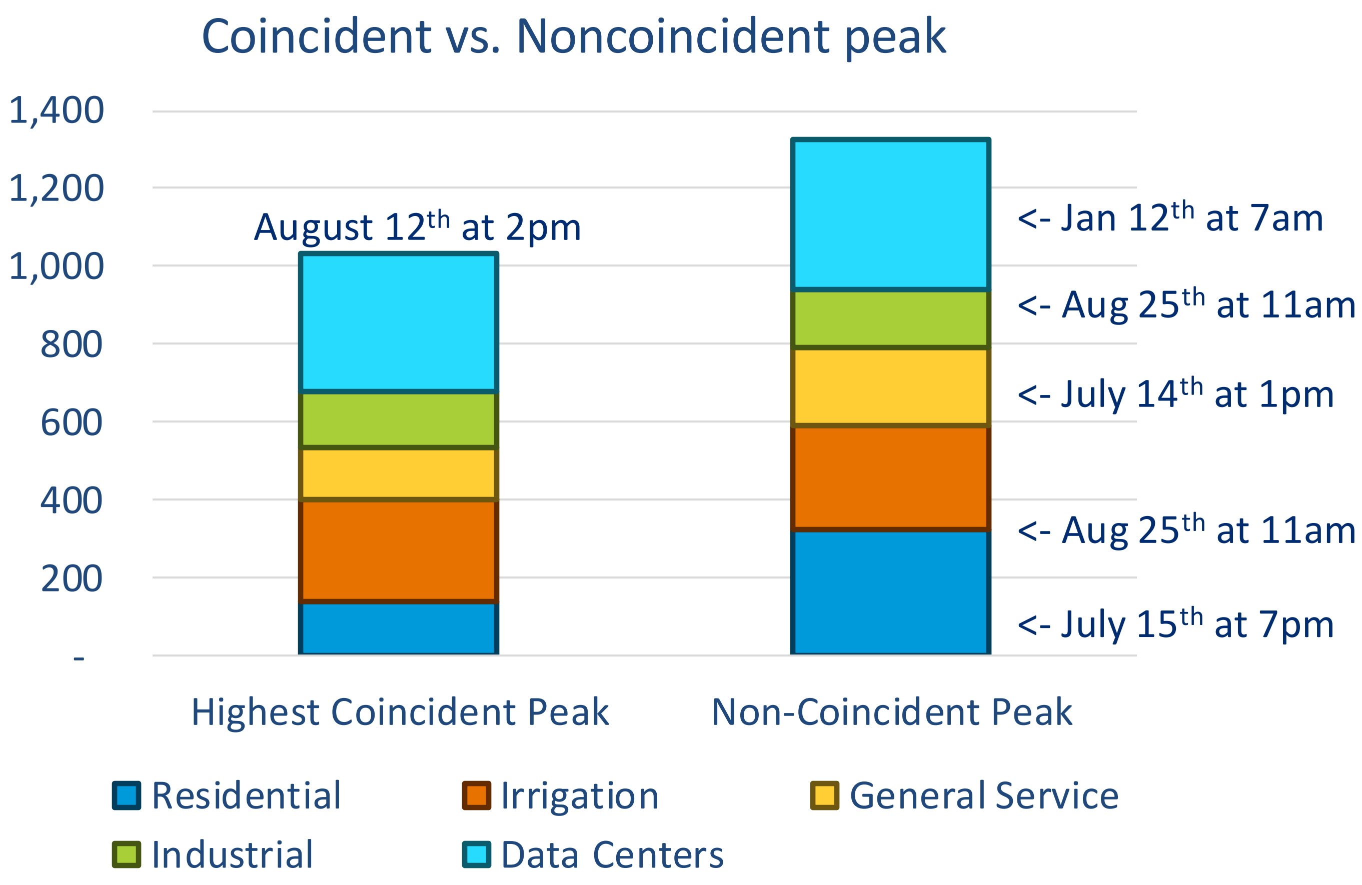
Coincident vs. Noncoincident Peak

Coincident Peak

- Occurs during max system usage
- Average of 12 monthly coincident peaks
- Measures burden on the *system*

Non-Coincident Peak

- Occurs during max rate-class usage
- Independent of coincident peak
- Highest annual peak for each rate class
- Measures burden to serve the site



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2025 Retail Electric Cost-of-Service Analysis

Rates & Pricing

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Index

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Executive Summary

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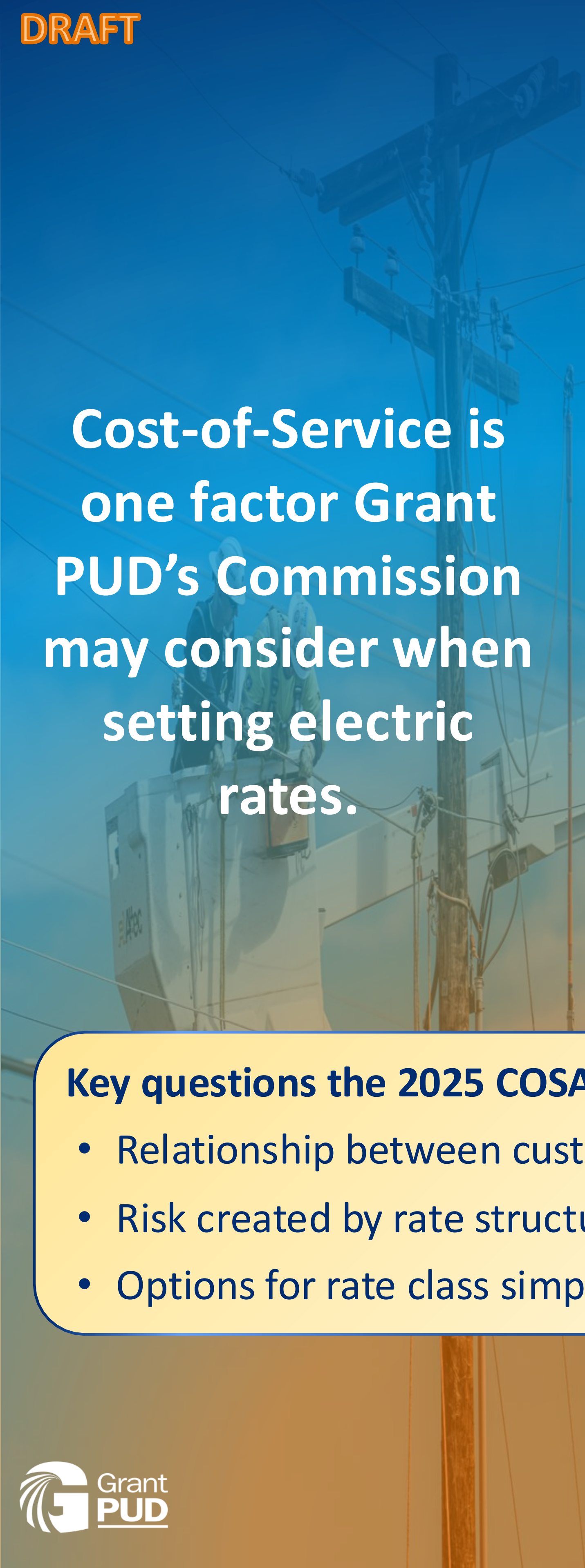
Introduction



Cost-of-Service is one factor Grant PUD’s Commission may consider when setting electric rates.

Rate Policy Resolution 9111 requires Rates & Pricing to complete a cost-of-service analysis (COSA) every two years.

The 2025 COSA is focused on <u>costs</u> incurred by customers of Grant PUD’s Retail Electric system. The COSA uses high-level assumptions to explore cost-causation between groups of customers.

Cost-causation relationships explain cost drivers within the Retail Electric system and provide Grant PUD commissioners a <u>lagging</u> measure to assist rate setting.

Key questions the 2025 COSA will answer:

- Relationship between customer bills and utility costs
- Risk created by rate structures
- Options for rate class simplification

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Segments and Rate Classes

Grant PUD organizes customers by segment and rate class.

- Segments (Core, Tier 1, and Tier 2) organize customers by ability to shift loads in response to price signals (elasticity) and risk associated with load growth.
- Rate classes separate customers by system usage characteristics such as load profiles, customer service needs, or unique risk profiles.
- Rate schedules identify how customers within a rate class are billed for service.

Core

Residential
General Service
Irrigation
Ag Service

Organic growth

Inelastic demand

System growth = Risk

Tier 1

Lg General Service
Industrial
Industrial Ag

Step-change growth

Elastic demand

System growth = mixed prospects

Tier 2

Large Industrial
Evolving Industry
Commercial EV Charging
High Density Compute

Rapid & speculative growth

Elastic demand

Growth = Business opportunity

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COSA Process

The 2025 COSA is a fresh look at Grant PUD cost-of-service and built from the ground up to accommodate the Commission approved Unbundled Power Supply Methodology and current structure of Grant PUD business functions.

GDS Associates reviewed the model to ensure structure and methods generally followed industry standards and made allocation choices that are fair and reasonable within the various industry standard choices for allocating costs.

The COSA segments Grant PUD's Electric System financial statement, calculates Return on Rate Base, assigns business function and charge method classified by FERC accounts, and allocates dollars to rate classes. The final product creates three perspectives to understand rate design and cost causation at Grant PUD.

Perspectives

COSA – Revenue: Compares 2025 retail revenue with cost-of-service allocated 2025 costs. Useful to understand who benefits from surplus wholesale funds.

Charges: Compares a pure cost-of-service rate structure with Grant PUD's 2025 rate structure. Useful to understand risk created by rate structures and identify simplification opportunities.

Functions: Examines the cost of specific utility services used customers. Useful to compare rate class and identify consolidation options.

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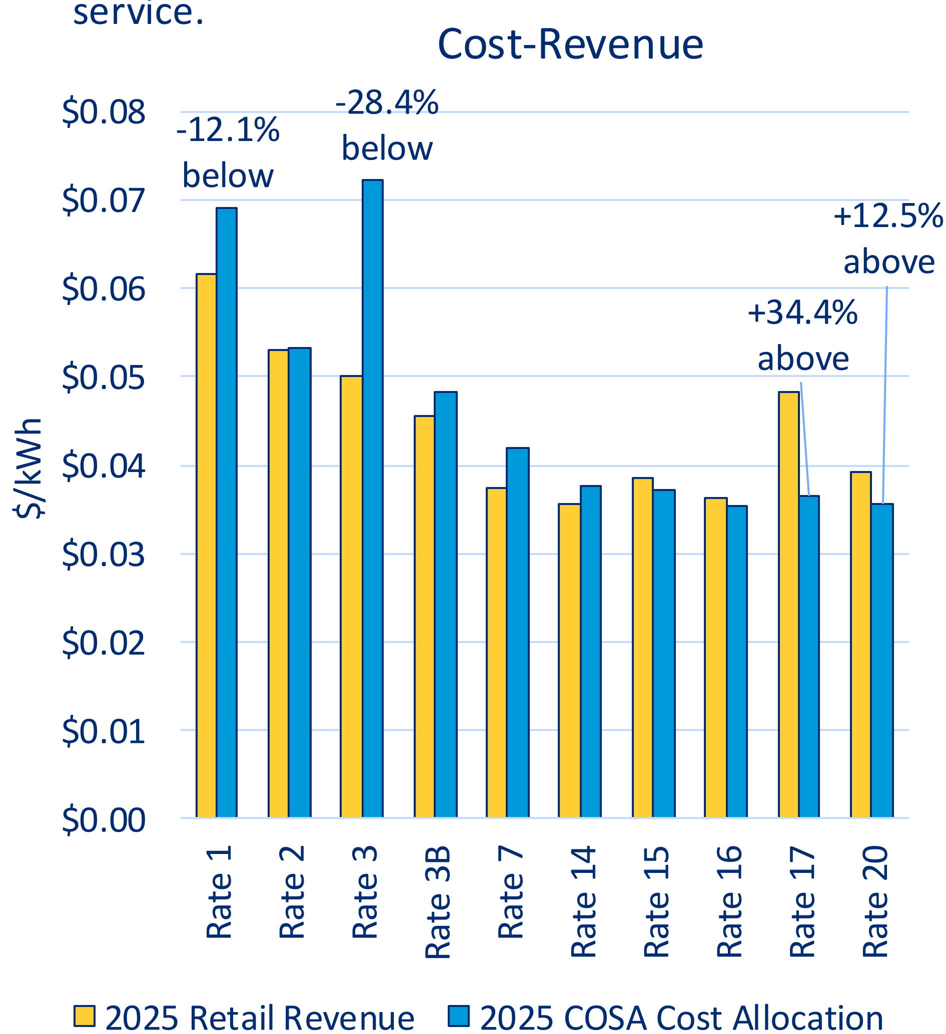
COSA – Revenue

Perspective

Relationship between customer bills and utility costs

The COSA – Revenue Perspective compares Cost-to-Serve results to 2025 Revenue to determine if customers are above, at, or below their cost-of-service results. Four[1] rate classes fall outside of the industry standard +/- 10% cost-of-service ratio[1].

- Residential (Rate 1) and Irrigation (Rate 3) revenue is more than 10% below cost-of-service.
- Evolving Industry (Rate 17) and High-Density Compute (Rate 20) revenue is 10% above cost-of-service.



[1] Rates 6, 19, and 85 were excluded due to their small size and large delta between cost-of-service and COSA results. See the results section for details on these rates.

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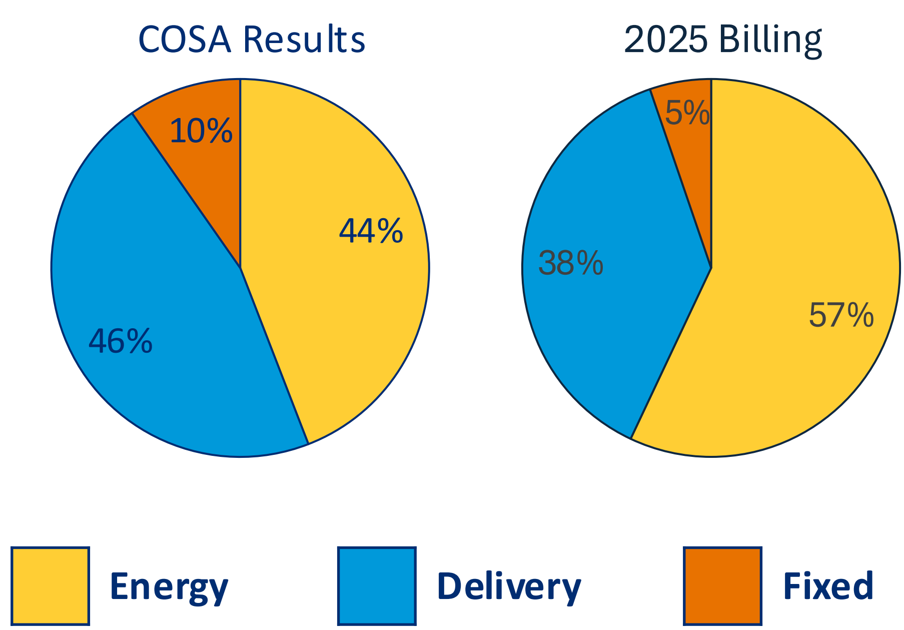
Risk created by rate structures

Charges

Perspective

The Charges Perspective compares a modified 2025 rate structure[1] with a pure cost-of-service rate structure. The 2025 rate structure was modified to simulate the Commission approved Unbundled Power Supply Methodology implemented in April 2026.

- Compared to prior studies the Unbundled Power Supply Methodology and new approach to JLB interest shifted cost away from power supply and reduced non-operation benefits credited against delivery.
- Most rate classes feature rate schedules with lower fixed costs than the pure cost-of-service rate structure.



[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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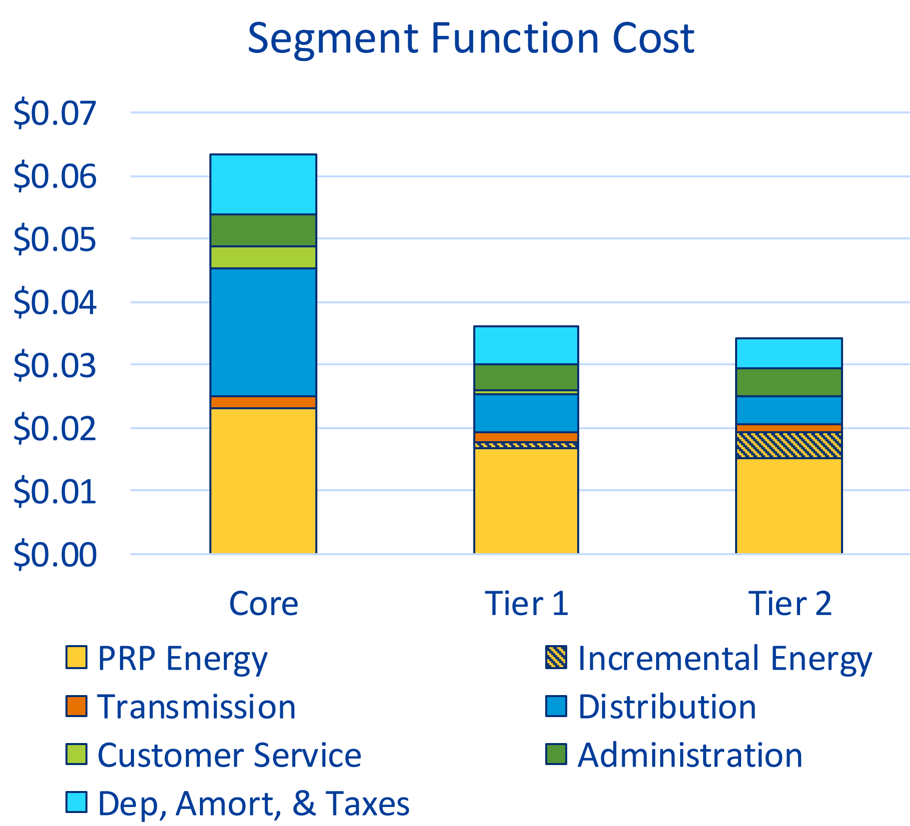
Options for rate class simplification

Functions

Perspective

The Functions Perspective examines the cost to provide specific utility services.

- Preferential access to power from the Priest Rapids Project provides initial lower Core power supply costs. However, line losses and peak capacity characteristics of Core rate classes create higher costs within the COSA model.
- The dispersed nature of Core customers causes significantly higher distribution and depreciation costs compared to Tier 1 and Tier 2 customers.
- Similarities between Tier 1 and Tier 2 power delivery and customer service + admin costs indicate opportunity to simplify rate structures.



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Recommendations

Create a new High-Density Compute rate class (Rate 20)

Reclassify Large Industrial (Rate 15) and Agriculture Boiler (Rate 85) segments

Develop a plan to restructure General Service and Industrial rate classes

Simplify rate structures

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Cost-of-Service Process

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Financial data is the foundation for all cost-of-service studies

2025 Financial Data

COSA Process

Grant PUD produces financial reports for the Priest Rapids Project, the Electric System, and a consolidated view of both systems.

Priest Rapids Project costs are calculated and recovered via a proforma financial statement. The electric system is the largest customer of Priest Rapids Project, paying 87% of cost in 2025. These costs are incurred as purchased power by the Retail Electric system.

Electric System Financials A provides plant assets, operating revenue and expense, taxes, amortization, and non-operating expense and revenue. Depreciation schedules provided by Accounting provide accumulated depreciation to calculate plant book value and annual depreciation.

The FERC chart of accounts is used to organize data and tie the Electric System Financials A to Depreciation schedules.

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Segments and Rate Classes

COSA Process

Grant PUD organizes customers by segment and rate class.

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Elastic demand

System growth = mixed prospects

Tier 2

Large Industrial
Evolving Industry
Commercial EV Charging
High Density Compute

Rapid & speculative growth

Elastic demand

Growth = Business opportunity

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Cost-of-Service Analysis Process

COSA Process

1. System Allocation

- Assign financial statement line items to business function
- Organize by FERC chart of accounts
- Allocate shared costs to business function
- Calculate Net Plant and Return on Rate Base

2. Assign Function and Classify Charges

- Assign system function labels to FERC accounts
- Assign volume, demand, or fixed classes to FERC accounts
- Break out FERC accounts as needed

3. Allocate to Rate Class

- Allocate expense and Return on Rate Base to rate classes

4. Analyze Results

- Compare total cost-of-service revenue with actuals
- Contrast COSA rate structure with current rate schedules
- Explore impact of non-operation costs and revenue
- Identify topics for future discussion

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2025 COSA Changes: Organization

COSA Process

The 2025 COSA deviated from prior cost-of-service studies to improve cost – causation, cost allocation, and improve transparency between Grant PUD businesses.

High Density Compute (Rate 20)

- Data processing, including data centers, cloud computing, AI training, and other non-cryptocurrency data processing customers, were grouped into a separate rate class for the 2025 Cost-of-Service Analysis.

Fiber and Transmission COSA Separation

- Updated system allocation methodology assigns transmission and fiber depreciation to separate cost-of-service studies.
- **$22M lower distribution depreciation expense**

CIAC and depreciation allocation

- Updated CIAC methodology credits CIAC payments against depreciation based on rate class contribution.
- **$7M lower depreciation expense (CIAC credit)**
- **$14M higher Non-Operation (removed benefits)**

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3

System Allocation

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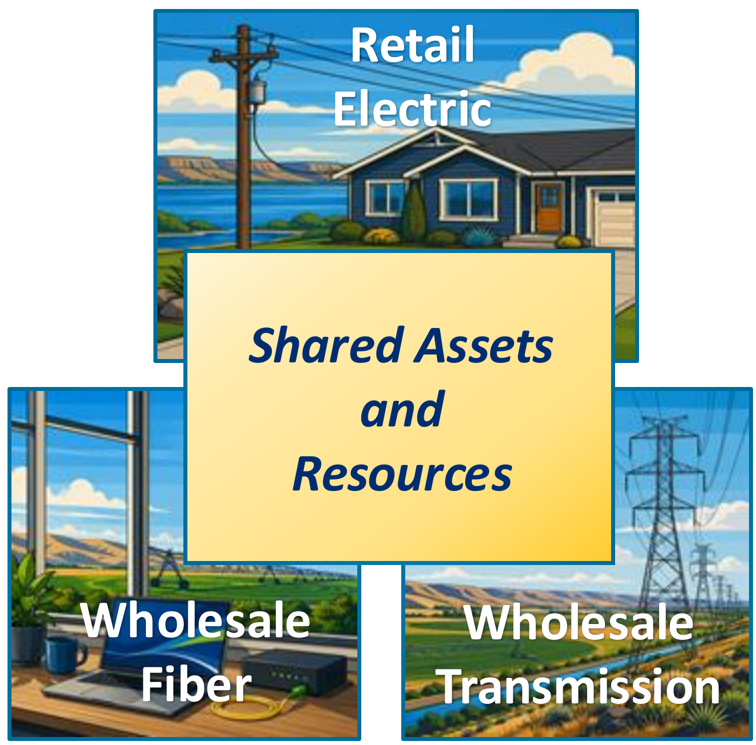
Electric System Businesses

System Allocation

Three business functions share the Electric System financials. The business functions serve different customers and collect revenue through different mechanisms. These business functions share assets and resources that must be isolated to complete the Retail Electric COSA. Failure to isolate assets creates potential for cross function subsidy between business functions.

- **Retail Electric:** Electric service to homes, business, and industries located within Grant County.
- **Wholesale Transmission:** Transmission services to Retail Electric customers, transmission and distribution services to non-retail customers within Grant PUD's balance authority, and wholesale transmission services to entities moving electricity across Grant PUD's transmission system.
- **Fiber:** Wholesale fiber services to Internet Service Providers who provide retail internet to Grant County homes and businesses.



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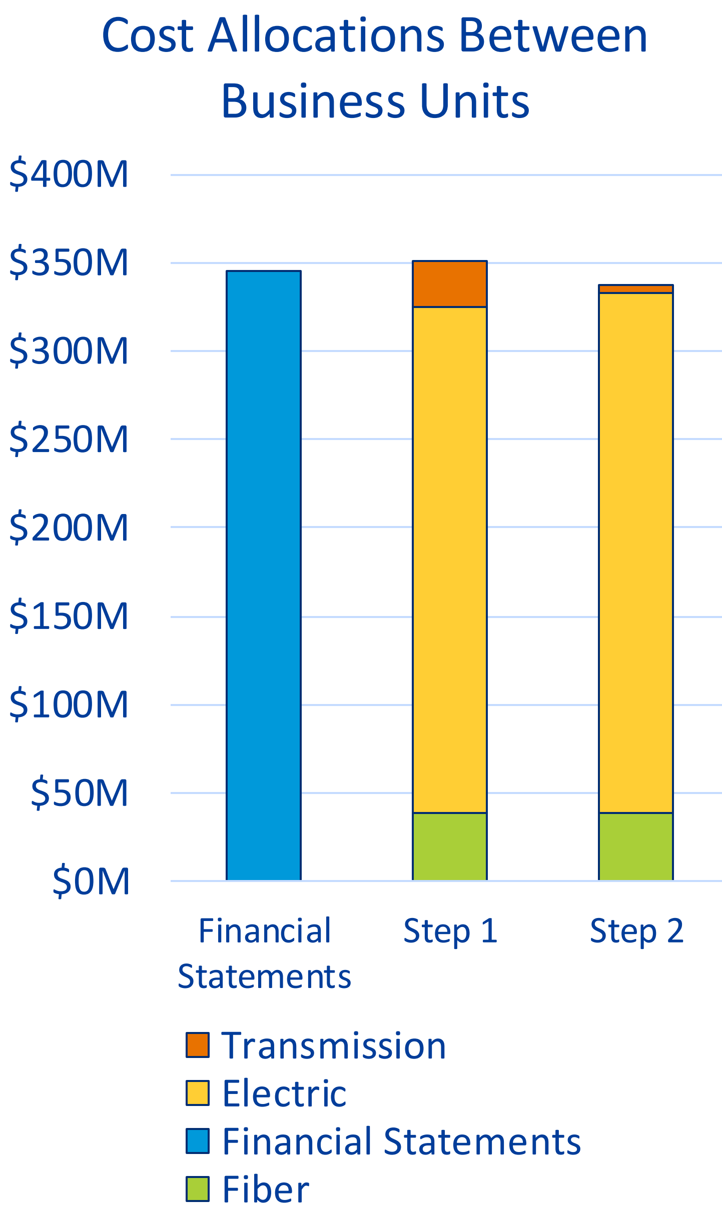
Process to Assign Financial Line Items

System Allocation

Revenues and expenses are assigned to the Retail Electric, Wholesale Transmission, and Wholesale Fiber systems through a two-step process.

Step 1: Book value, expense, and revenue line items from the Electric System Financials are assigned to Electric, Transmission, and Fiber functions. Line items may be wholly assigned or partially assigned based on System Allocators. Step 1 results exceed financial statement amounts due to exclusion of unrealized gain on investments.

Step 2: Retail Electric, Wholesale Transmission, and Wholesale Fiber financials created using Share of System Allocators that assign book value, expense, and revenue line items based on system use. Step 2 results are lower than Step 1 due to allocation of a portion of PRP to wholesale and CIAC credit which is partially offset by exclusion of JLB Interest and CIAC.



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Step 1: Financial Statement Allocation

System Allocation

Electric System Financials	Step 1
Return on Rate Base: $50M	Electric: $286M
Operating Expenses: $356M	Transmission: $26M
Non-Operating: -$61M	Fiber: $39M

Example: Allocating Outside General Services

Electric System Cost	Allocator	%	Step 1
		62.6	Electric: $3.5M
Outside General Services $5.5M	Dir_Non	15.1	Transmission: $0.8
		22.3	Fiber: $1.2M

- **Return on Rate Base: 76**% of dollars directly assigned to step 1 buckets. General & Intangible plant allocated using direct share of net plant for Electric, Transmission and Fiber.
- **Operating Expenses: 74**% of dollars directly assigned to step 1 buckets. Other dollars allocated using allocators such as percent of labor & non-labor costs and percent of net plant.
- **Non-Operation:** Bond income and expense allocated by share of gross revenue or net plant. JL-Bonds allocated to Electric System. Other revenues (service fees) allocated using percent of revenues.

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Share of Direct Labor and Non-Labor

System Allocators

Primarily used for Administration, General, and misc Overhead cost allocation in Step 1.

SYSTEM ALLOCATORS

Common Name	Allocator	Retail Electric	Transmission Wholesale	Fiber Wholesale
Direct Labor & Non-labor	Dir_L&N	69.85%	15.04%	15.11%
Direct Labor	Dir_Labor	71.44%	15.02%	13.55%
Direct Non-Labor	Dir_Non	62.61%	15.13%	22.27%
Direct Labor & Non-Labor E&T	Dir_L&N_E&T	82.29%	17.71%	0.00%

Allocator	Retail Electric	Transmission Wholesale	Fiber Wholesale	Total
Labor & Non-labor	$35,233,852	$7,584,325	$7,623,176	$50,441,354
Labor	$29,562,581	$6,214,173	$5,605,835	$41,382,590
Non-labor	$5,671,271	$1,370,152	$2,017,341	$9,058,764

Labor Allocation Costs

- Salaries & Wages
- Overtime
- Benefits

Non-Labor Allocation Costs

- Purchased Services
- Operating Materials
- General & Administrative
- Insurance
- Technology

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Step 2: Share of System Allocation

System Allocation

FERC Code flow via Share of System Allocators

Electric (Step 1) • RONA: $29M • Operation Expense: $307M • Non-Operation: -$50M	**Retail Electric System** • RONA: $36M • Operation Expense: $269M • Non-Operation: -$12M
Transmission (Step 1) • RONA: $8M • Operation Expense: $25M • Non-Operation: -$6M	**Wholesale Transmission System** • RONA: $1M • Operation Expense: $4M • Non-Operation: -$0M
Fiber (Step 1) • RONA: $13M • Operation Expense: $25M • Non-Operation: $1M	**Wholesale Fiber System** • RONA: $13M • Operation Expense: $25M • Non-Operation: $1M

- **Transmission -> Retail Electric:** Retail electric customers use ~ 89% of transmission system capacity. Transmission dollars allocated to Retail Electric based on share of average coincident peak.
- **Electric -> Wholesale Transmission:** Non-electric retail customers (irrigation districts) use ~ 0.2% of distribution system capacity. Distribution dollars allocated by non-coincident distribution peak, share of overhead and underground lines, share of meters, or weighted customer service value.
- **Wholesale Fiber:** Dollars are isolated within the accounting system, eliminating the need for a share of system allocation step.

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Return on Rate Base

System Allocation

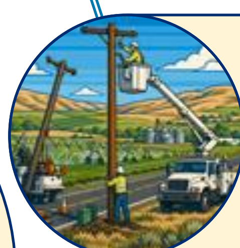
The COSA process allocates Net Book Value to systems by subtracting accumulated depreciation from the asset value for a net book value of $694M. Return on Rate Base is calculated by applying the District’s weighted average cost of capital to allocated Net Book Value. The result is $36.4M of Return on Rate Base to be allocated to rate classes.

Return on Rate Base

5.24%

Cost of borrowing

Cost of funding capital expenses



Replacement

Cost of replacement at end-of-life including inflation

Investment Tolerance

Foundation for business cases to compare investments

Risk Mitigation

Cushion in the event of early retirement due to catastrophe

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CIAC Depreciation Adjustment

System Allocation

LPS CIAC

Rate Classes: 7, 15, 16, 17, 20

$97M LPS CIAC Payments Received

2016 - 2025

$94M Recorded to Revenue

2016 – 2025

Revenue recognized in alignment with construction spend

Annual depreciation calculated in alignment with revenue recognition (20-year life)

Depreciation credit allocated based on LPS Rate Classes % of Contributions

Rate Class	Total CIAC 2016 – 2025	Depreciation Credit
7	$7,585,000	$379,000
15	$863,000	$43,000
16	$3,192,000	$159,000
17	$2,656,000	$133,000
20	$80,392,000	$4,020,000
Total	**$94,688,000**	**$4,734,000**

NON-LPS CIAC

Rate Classes: 1, 2, 3, 3, 6, 14, 19, 85

$46M Non-LPS CIAC Payments Received

2016 - 2025

$46M Recorded to Revenue

2016 – 2025

Revenue recognized in year of payment

Annual depreciation calculated in alignment with revenue recognition (20-year life)

Depreciation credit allocated based on Rate Classes % of Revenues

Rate Class	Depreciation Credit
1	$1,010,000
2	$530,000
3	$617,000
6	$24,000
14	$109,000
19	$8,000
85	$500
Total	**$2,298,000**

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Retail Electric System Allocations

System Allocation

Return on Rate Base	
Power Production	$2,000
Transmission	$5,353,000
Distribution	$28,407,000
Admin and General	$2,616,000
Total Return on Rate Base	**$36,378,000**

Operating Expenses	
Power Supply	$129,653,000
Transmission	$4,552,000
Distribution	$41,359,000
Customer Service	$7,992,000
Admin and General	$34,348,000
Operations & Maintenance	$217,904,000
Depreciation & Amortization	$30,009,000
Taxes	$21,548,000
Total Operating Expenses	**$269,461,000**

Total Non-Operation[1]	**-$11,980,000**

Total to allocate to rate classes	**$293,859,000**

[1] Non-operations includes significant interest income resulting in a net credit.

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Improvements for future studies

System Allocation

Rates & Pricing staff encountered several challenges during the data gathering phase. Staff will work with other departments within Grant PUD to improve accuracy for the 2027 cost-of-service study.

Large unspecified expenses

- $30M of electric system expense charged to general A&G.
- $21M charged to misc. distribution operating expense.
- **Solution**: Allocators developed using share of direct labor and non-labor expenses.

Cash & Investments

- Balances not tracked by retail electric, wholesale transmission, or wholesale fiber system
- **Solution**: Interest earnings allocated using revenue allocator.

Unspecified debt

- Debt funding costs not assigned to Wholesale Fiber or Transmission
- Existing debt not tied to specific assets
- **Solution**: Capital funding costs allocated using net plant values.

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4

Function & Charges

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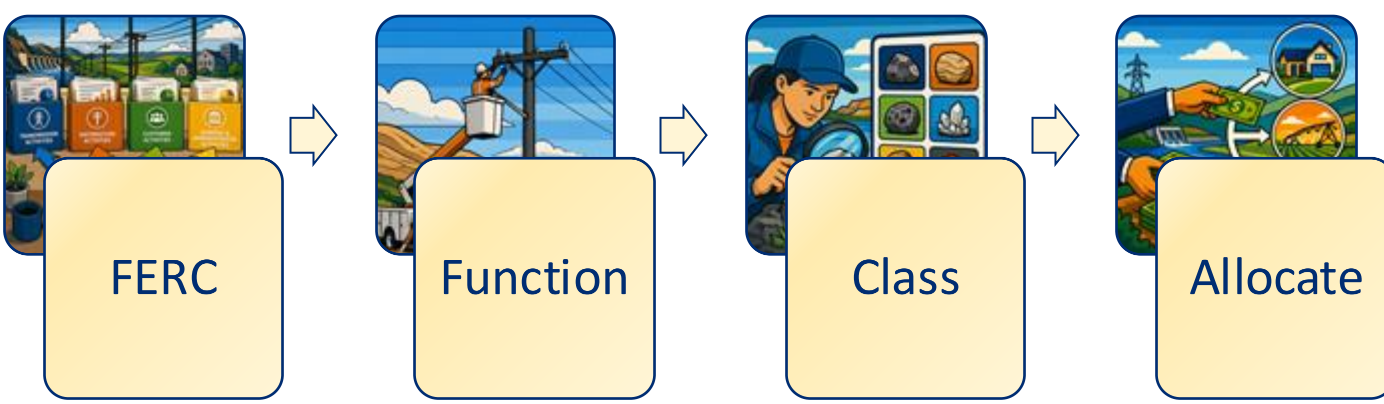
Assign and allocate plant and expense

Function and Charges

The cost-of-service analysis (COSA) uses a four-step process to assign "costs" (expense, Return on Rate Base, non-operation revenue and expense) to rate classes.

1. **FERC** Chart of Accounts: Organize costs by activity as the starting point to assign function, classify, and allocate costs. *Example: Overhead wires.*
2. **Function:** Ties FERC to utility activity responsible for cost-causation analysis between rate classes. *Example: Overhead wires are a Power Delivery function*.
3. **Class:** How customers experience costs on their bill. Costs may be experienced as a fixed cost or vary based on volume of energy or share of peak load. *Example: Overhead wires classified as fixed – the cost to maintain wires is relatively independent of demand compared to customers within the same rate class.*
4. **Allocate**: Allocates FERC organized costs to rate classes based on share of system use. *Example: Overhead wire costs allocated to rate classes by the percent of total line miles serving retail electric customers.*



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FERC Chart of Accounts

Function and Charges

The Federal Energy Regulatory Commission Chart of Accounts provides framework necessary to functionalize, classify, and allocate costs to rate classes

The term "Costs" are shorthand for the sum of Expense, Return on Rate Base, and Non-Operation Revenue and Expense

Physical Plant – FERC 300 – 399, 100 - 129

- Total value and accumulated depreciation of physical assets used to calculate RONA (Return on Rate Base).

Operating Expenses – FERC 500 – 599

900 – 935, 403 – 404, 408

- Power supply purchases, operation and maintenance of Transmission, Distribution, Customer Service, and Administrative systems, Depreciation & Taxes

Non-Operating – FERC 415 – 430, 460

- Interest income & expense, other income & expenses, CIAC

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Function

Function and Charges

Function identifies where revenue requirements originate for discussion and comparison *between* rate classes. Assigning function allows cost causation analysis between rate classes.

The 2025 Cost-of-Service analysis separates the following functions:

- Power Supply
- Power Delivery
- Customer Service + Admin
- Non-Operation

Additionally, several non-operation functions are isolated to improve clarity:

- Other Revenue
- Depreciation (on shared assets)
- Amortization (on shared assets)
- Taxes

FERC codes are linked to the appropriate function.

Intangible cost items were functionalized as Customer Service + Administrative.

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Charges

Function and Charges

Charges classification identifies the method used to allocate costs *within* rate classes.

Energy

- Dollars paid by customers based on volume of energy consumed. Represents Grant PUD's cost share of Priest Rapids Project and Power Purchase Agreements entered into on behalf of customers. Billed by volume of energy delivered ($/kWh).

Delivery

- Dollars paid by customers based on share of peak demand or service. Represents Grant PUD costs that increase with volume. Building and maintaining electrical distribution equipment, most administrative costs, and some customer service costs are considered delivery. Billed by volume of energy delivered ($/kWh) or peak capacity used ($/kW).

Fixed

- Dollars paid by customers based on flat rate. Represents Grant PUD costs where volume of use does not increase cost. Examples include meters, distribution lines, most customer service costs and some administrative costs. Billed at a flat rate per customer ($/day or $/month).

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5

Rate Class Allocation

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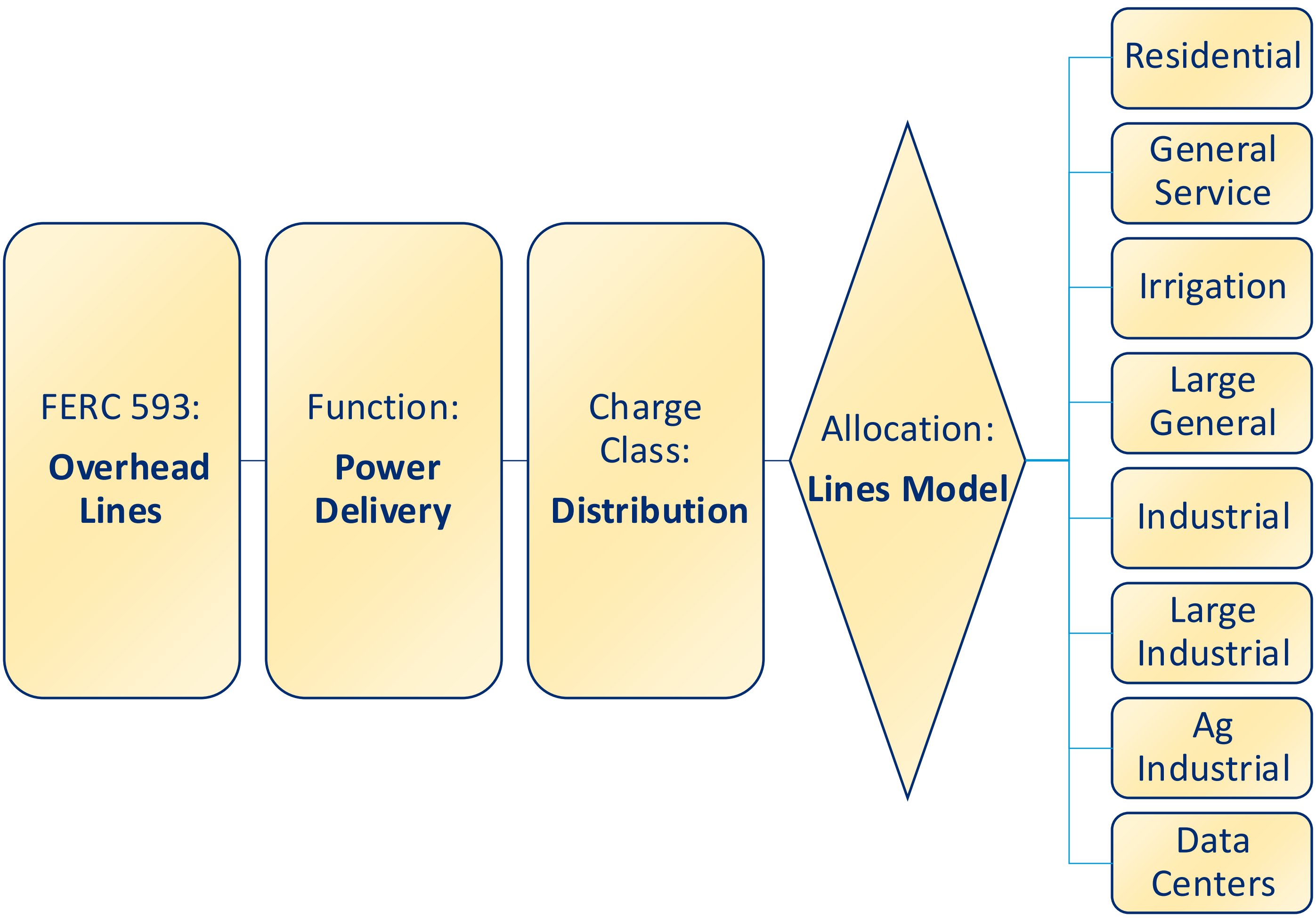
Rate Class Allocation

Rate Class Allocation

Rate Class allocation assigns functionalized and classified charges to rate classes using allocators that estimate the cost of providing services. Results create the COSA-Revenue, Charges, and Functions perspectives.



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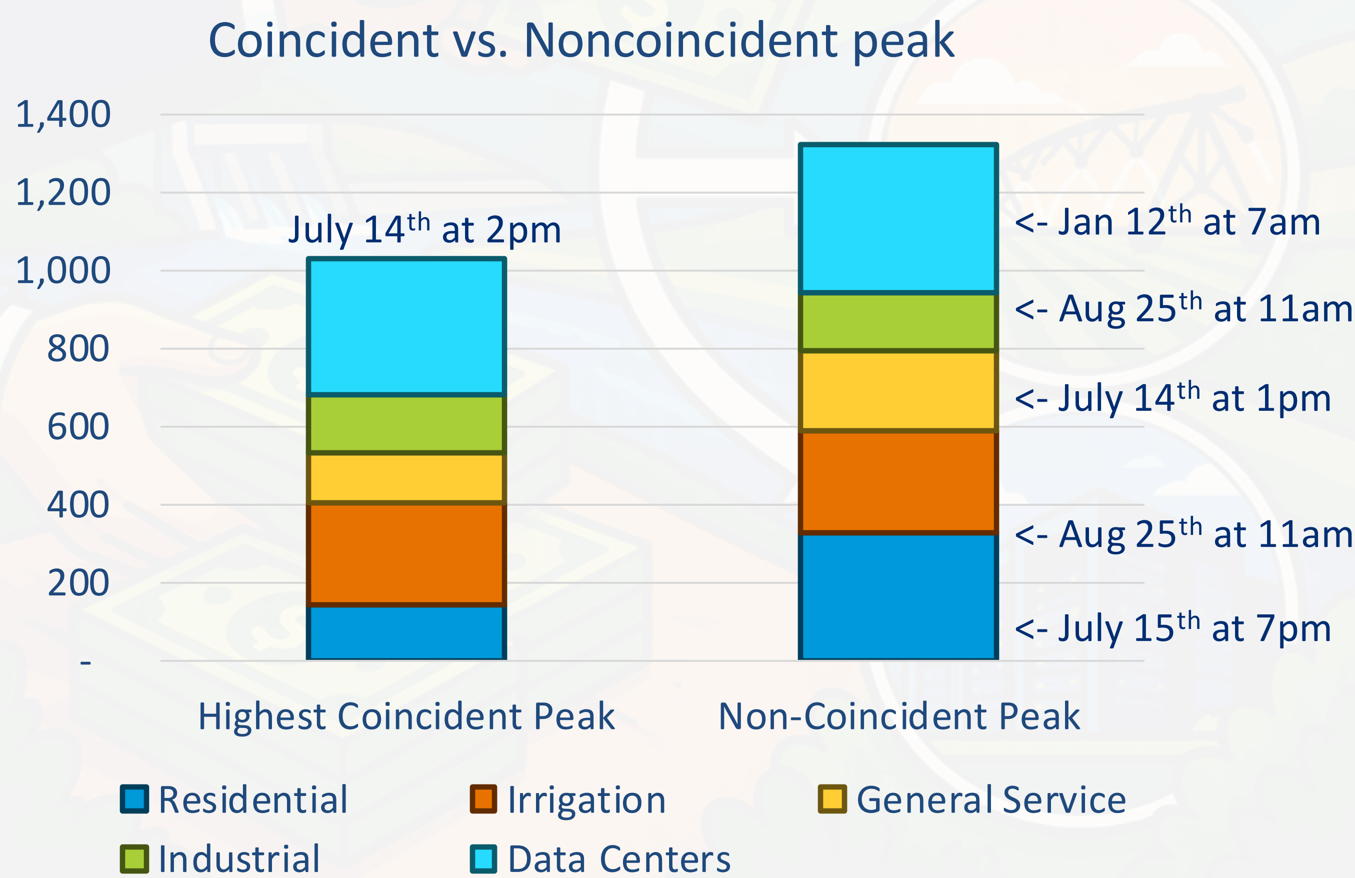
Coincident vs Non-Coincident Peak

Rate Class Allocation

Both coincident and non-coincident peak are used to allocate transmission and distribution costs to systems and rate classes.

- Coincident Peak is the largest hourly MW peak observed each month across the transmission and distribution systems.
- Non-coincident peak is the largest hourly MW peak observed for transmission system users or rate classes each month.
- Coincident and non-coincident peaks do not necessarily occur at the same time.



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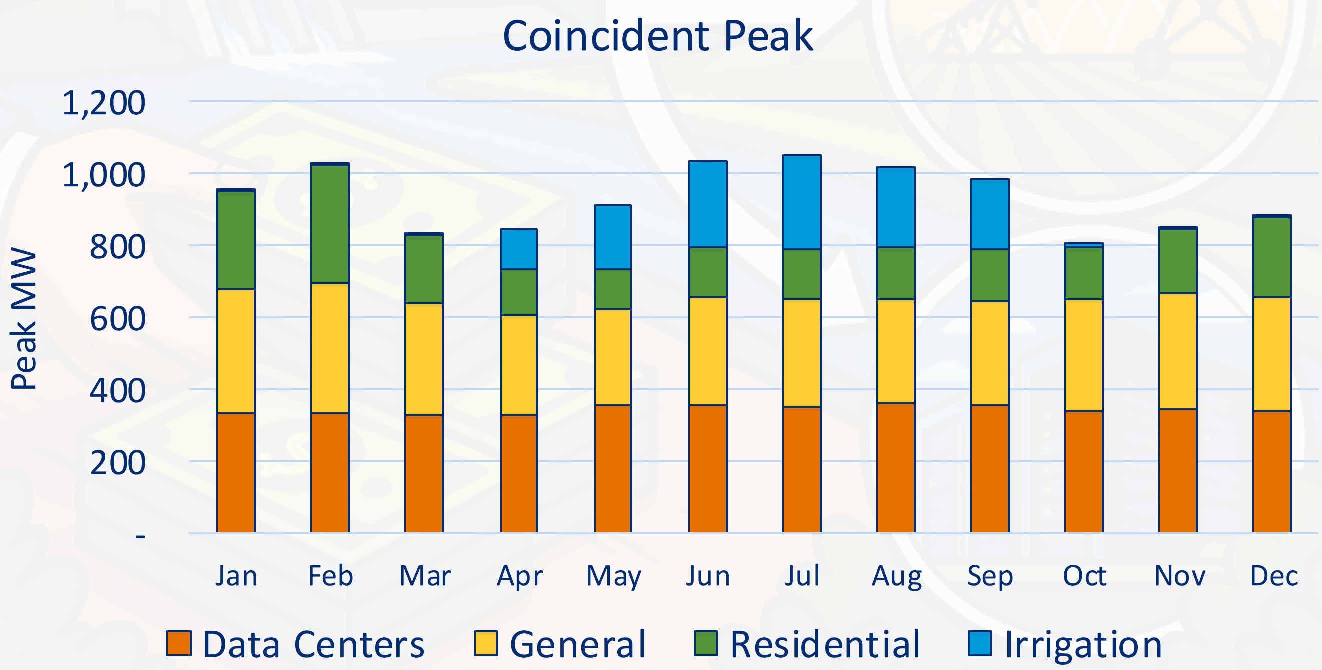
Transmission Allocation

Rate Class Allocation

All Transmission costs were allocated using average coincident peak. This matches the methodology used to allocate transmission costs to wholesale transmission customers.

Coincident Peak 12

- Transmission systems are designed to accommodate maximum system peak.
- Coincident Peak 12 is calculated by averaging each rate class's share of 12 monthly system peaks.
- Coincident Peak 12 was selected because Grant PUD's system did not pass FERC (the Federal Energy Regulatory Commission) threshold for allocating based on a single month or selection of peak months.



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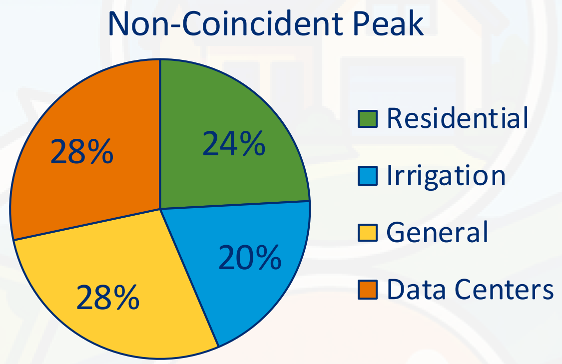
Distribution Allocation

Rate Class Allocation

Distribution costs were allocated using non-coincident peak, overhead and underground lines, and meter counts.

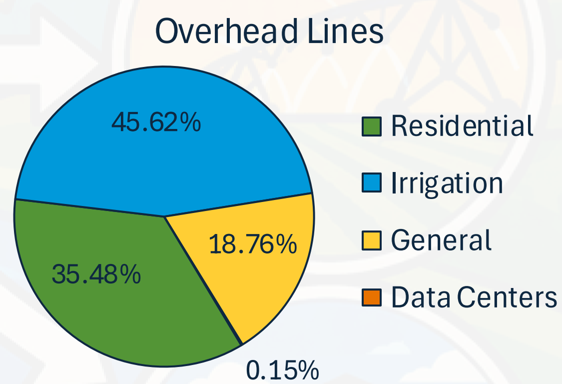
Non-Coincident Peak

- Secondary transformers are sized based on individual customer peak load (independent of system load).
- Calculated based on highest observed rate class peak over 12 months.



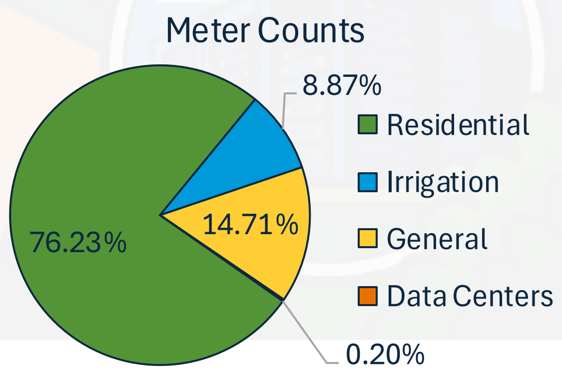
Overhead & Underground Lines

- Miles of lines serving the rate class.
- Based total feeder miles and service phase. Overhead and underground service calculated separately.



Meter Counts

- Count of premises served by meters.



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Customer Service & Admin Allocation

Rate Class Allocation

Customer service costs were allocated based off number of customers or a weighted customer service allocator. Administrative costs that were generic in nature were allocated based of share of revenue.

Unique Premise ID and Badge Number

- Percent of total premises or meter numbers. Used for customer service and fixed administration allocations.

Sum of Sales

- Percent of total retail sales. Used for customer service or administration allocations where customer size would impact our cost to serve.

Weighted Customer Service

- Customer Solutions estimate of effort to serve relative to 1 residential customer (Core).
- Large Power Solutions estimate of time spent serving rate classes (Tier 1 and Tier 2).

Rate Class	Weight	Total	Percent
Rate 1 Residential	1	43,346	44%
Rate 2 General Service	3	24,756	25%
Rate 3 Irrigation	5	25,030	25%
Rate 7 Large General	10	1,740	2%
Rate 14 - 20 Industrial	50	3,127	4%

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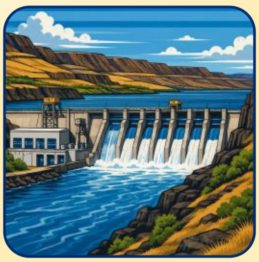
Power Supply allocation changes

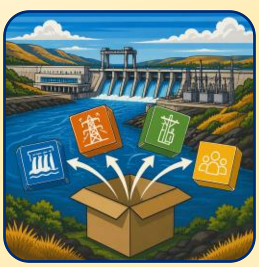
Rate Class Allocation

The new cost-of-service analysis (COSA) was updated to include Unbundled Power Supply Methodology. The update crated major differences between the 2025 results and past COSA results. The net result was shifting $67.5M from power supply cost allocation to reducing revenue credits by a similar amount.



Priest Rapids Project JL Bonds

- JL Bond interest payment and earnings were removed because it is intersystem activity that has a neutral overall impact.
- **$22.5M lower Power Supply expense**
- **$22.5M higher Non-Operation expense**



Unbundled Power Cost Allocation

- Unbundled Power Supply Methodology allocates unused PRP costs against wholesale transactions.
- **$45M lower Power Supply expense**
- **$45M less Wholesale Revenue credit**

Wholesale Credits

- Wholesale power credits not allocated to specific rate classes but against Grant PUD’s revenue requirement.
- $253M surplus wholesale revenue was used to subsidize rates and cash fund capital projects.

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Power Supply Allocation

Rate Class Allocation

Energy allocation assigns costs *to* tiers (Core, Tier 1, Tier 2) through a three-step process

Step 1: Priest Rapids Project costs allocated to Core based on energy used. Core energy costs are fully allocated after Step 1.

Step 2: Tier 1 and Tier 2 Priest Rapids Project costs are allocated based on energy used minus incremental power energy assigned in Step 3.

PRP Assignment: Dollars from Steps 1 and 2 are totaled and allocated across all rate classes based on energy and capacity.

Segment	MW Load	Dollars
1. Core Priest Rapids Project	2,016,220	$37.0M
2. Tier 1 & Tier 2 Priest Rapids Project	4,141,760	$76.4M
3a. Tier 1 Incremental Power	30,755	$1.9M
4b. Tier 2 Incremental Power	233,501	$14.1M
4. Wholesale Priest Rapids Project	2,444,420	$45.0M

Step 3: Power Purchase Agreement resources ranked from least to most expensive and assigned based on 10-year growth projections.

Step 3a: Tier 1 share of incremental power supply is allocated from the least cost resource until Tier 1 share of incremental power is met.

Step 3b: Remaining incremental power supply resources allocated to Tier 2.

Incremental Assignment: Dollars from Step 3a and 3b are individually allocated across Tier 1 and Tier 2 rate classes.

Step 4: Remaining Priest Rapids Project costs allocated to net wholesale activity. These costs represent power purchased above expected load for shaping, risk mitigation, and to meet contract obligations.

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Energy and Capacity Allocation

Rate Class Allocation

Energy resource costs are divided into Energy and Capacity costs for Priest Rapids Project and Incremental Power resources.

- Energy represents the volumetric nature of energy supply. Energy dollars are assigned to rate classes based on total kWh consumed plus line losses.
- Capacity is the ability of energy generation to meet peak demands. Capacity dollars are assigned to rate classes based on share of coincident peak during WRAP months (June – September and November – March).
- Generation Capacity is calculated using the ratio of nameplate capacity to net generation.
- Effective Load Carrying Capacity (ELCC) uses WRAP Qualified Carrying Capacity value from Grant PUD's integrated resource plan.
- Incremental resources include Goose Prairie Solar, Nine Canyon Wind, and BPA Hydro.

Priest Rapids Project	$159M
EIA 860 Nameplate	2,170 MW
EIA 923 Net Generation	8,602,397 MWh
Generation Capacity	45%
IRP QCC	80%
Energy / Cap split	36% Energy 64% Capacity
Assignment	$57M Energy $101M Capacity

Incremental Resources	$15.4M
EIA 860 Nameplate	108 MW
EIA 923 Net Generation	264,256 MWh
Generation Capacity	28% (weighted)
IRP QCC	36% (weighted)
Energy / Cap split	44% Energy 56% Capacity
Assignment	$6.7M Energy $8.7M Capacity

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Improvements for future studies

Rate Class Allocation

Rates & Pricing staff identified several areas to improve accuracy for the 2027 cost-of-service study.

Large unspecified expenses

- $30M of electric system expense charged to general A&G.
- $21M charged to misc. distribution operating expense.
- **Solution**: Allocators developed using share of direct labor and non-labor expenses.

Normalize budget, weather, and load

- Normalizing budget, weather, and load would prevent odd-ball years pushing COSA results and improve year-to-year comparisons.
- **Solution**: Identify differences between 2025.

Improve customer service allocation

- While using weighted customer counts is a standard industry practice a study to examine timecard allocation could improve accuracy.
- **Solution**: All weighted values vetted with customer solutions and administrative staff.

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6

Results Summary

Details by Segment and Class

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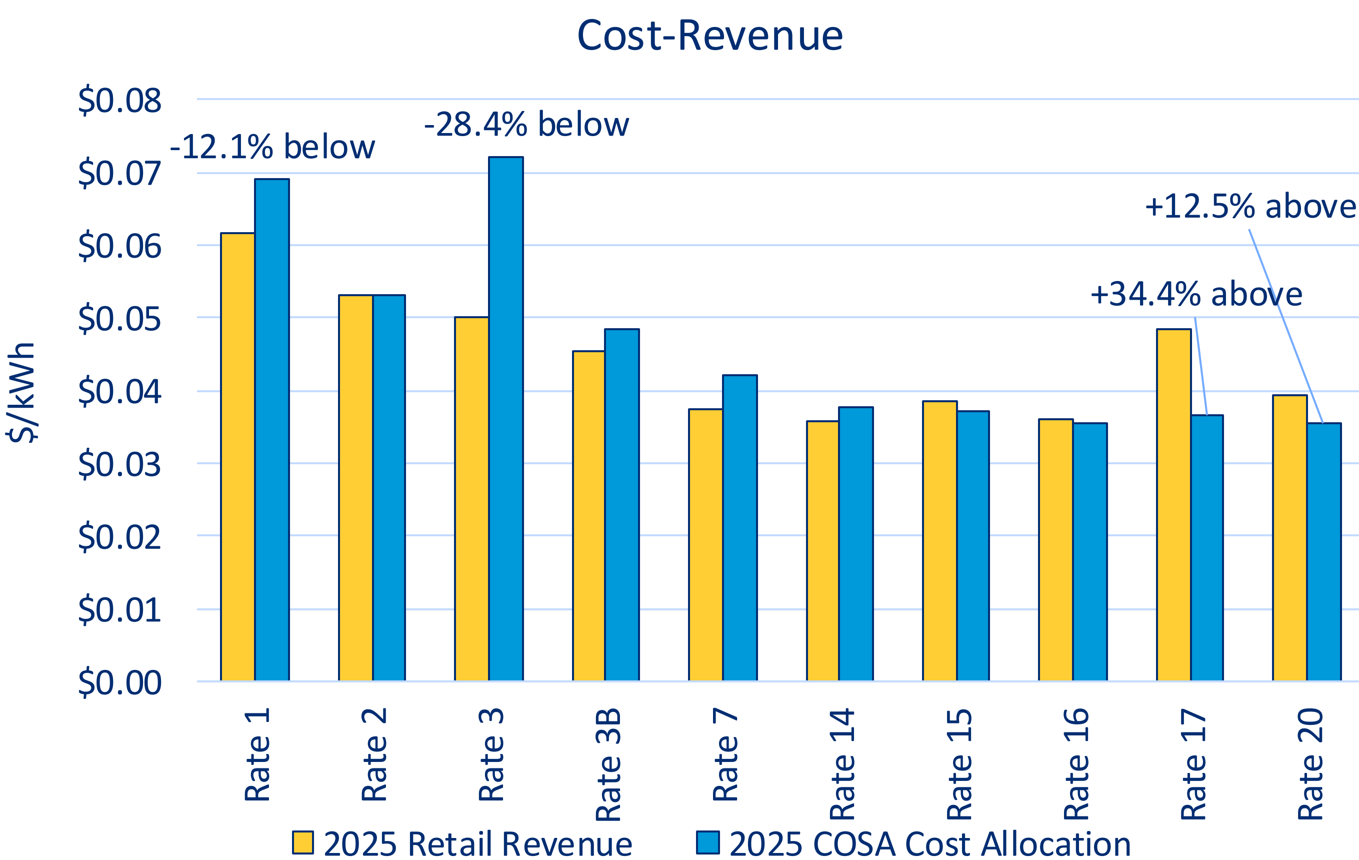
COSA – Revenue Perspective

Results Summary

The COSA – Revenue Perspective examines the difference between cost-of-service results and 2025 revenue by rate class. Grant PUD use of excess wholesale profits can provide a social benefit - allowing some rate classes to pay below cost-of-service results. Most Grant PUD customers pay +/- 10% their cost-of-service.

- Most Core rate classes pay below their cost-of-service with Residential (Rate 1) paying 12.1% and Irrigation (Rate 3) paying 28.4% below cost-of-service.
- Tier 1 and Tier 2 are mixed with smaller rate classes paying below cost-of-service results and Large Industrial (Rate 15), Evolving Industries (Rate 17), and High-Density Compute (Rate 20) paying above.



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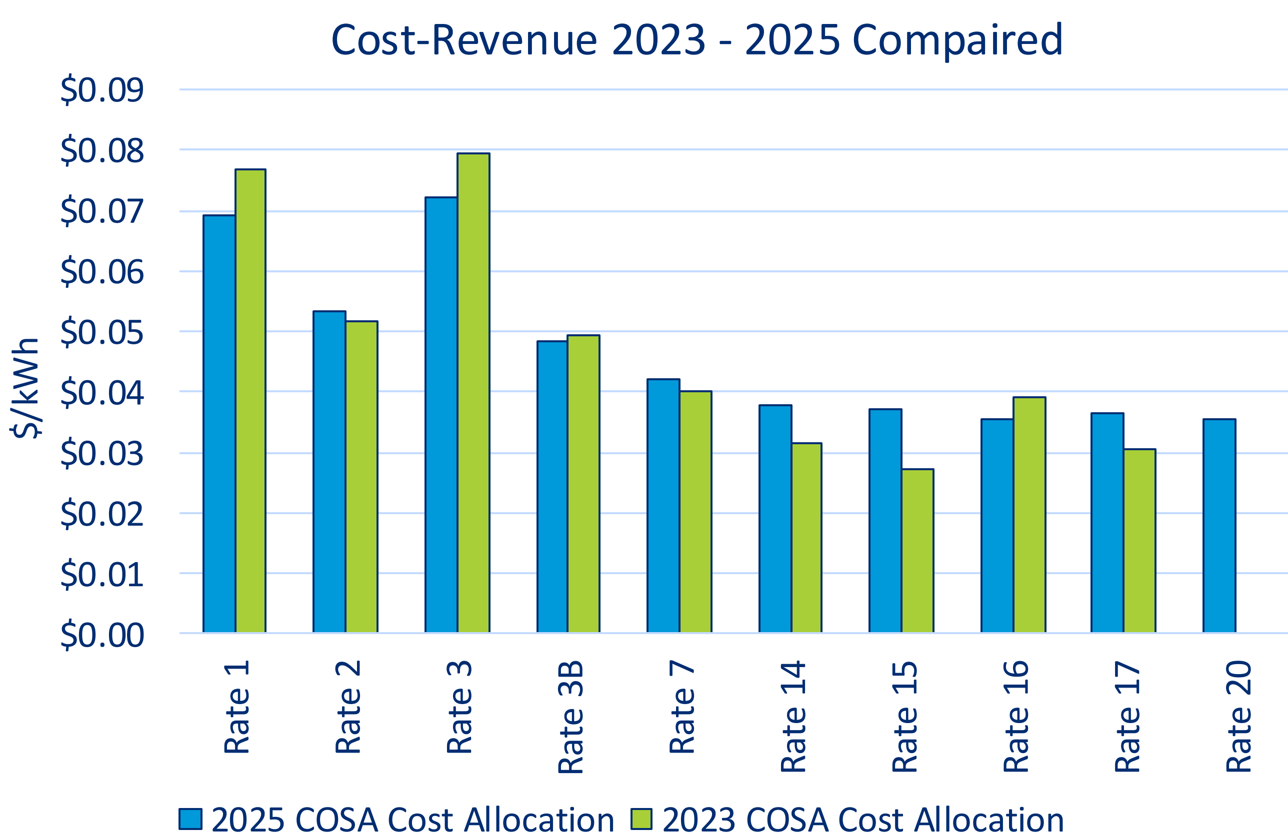
COSA – Revenue: 2023 v 2025

Results Summary

Power Supply allocations account for 87% of COSA – Revenue differences between the 2023 and 2025 cost-of-service studies. This change reflects updating the 2025 COSA model to include the Unbundled Power Supply Methodology.

- The 2025 study removed $22.5M of Priest Rapids Costs and $22.5M of non-operations benefits to offset PRP JL Bond expenses.
- The 2025 study assigned $45M of PRP costs against wholesale power instead of allocating against rate classes. Total wholesale benefit was $253.1M and was used to subsidize rates and cash fund capital projects.
- The 2023 study assigned $72.3M of wholesale revenue directly to rate classes. This number was normalized from $152.3M actuals in 2023.



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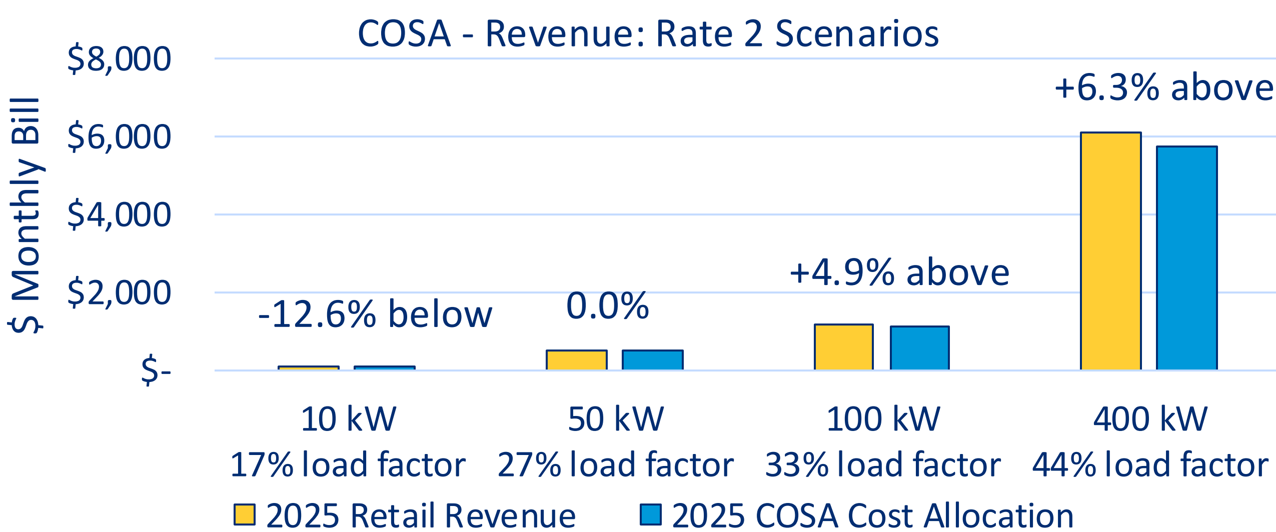
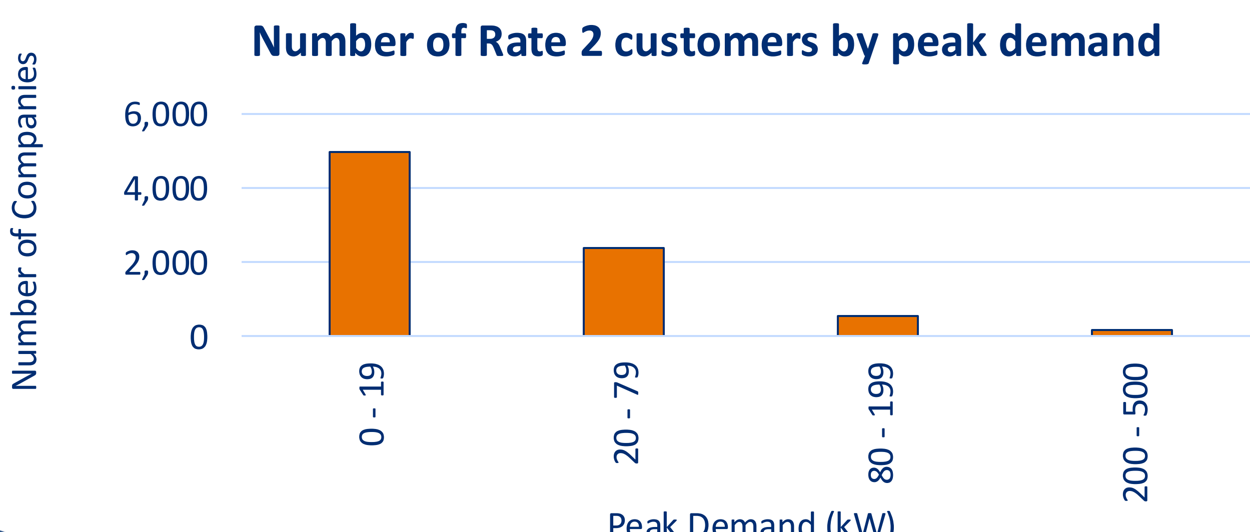
COSA – Revenue: Rate 2

Results Summary

Rate 2 (General Service) has over 8,000 customers with a wide variety of service sizes and load factors.

- The current billing structure favors the smallest customers with poor load factors due to the kWh structure of delivery costs.
- kWh was chosen for delivery to optimize billing for small customers.
- Most Rate 2 customers are under 20 kWh / month.





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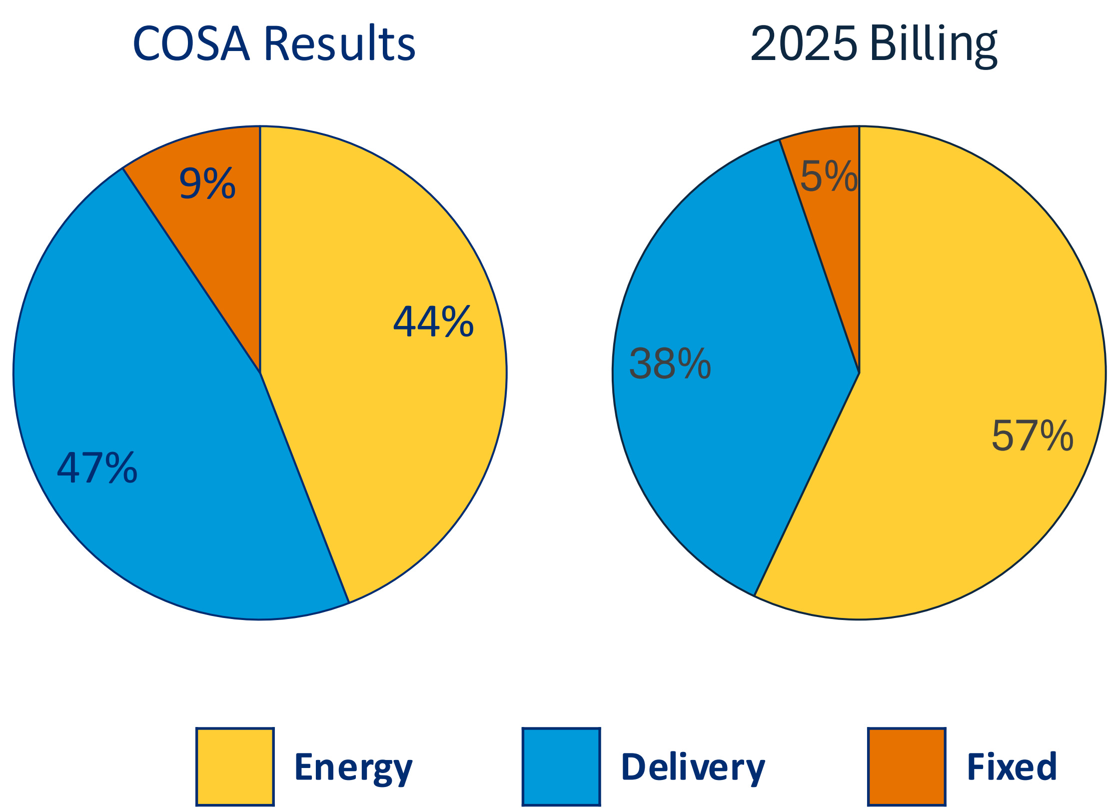
Charges Perspective

Results Summary

The Charges Perspective compares a modified 2025 bill structure[1] to COSA results. Rate design should imitate how utility experiences costs - significant deviation puts revenue collection at risk should customer behavior change from expected due to business needs, weather, or consumer trends.

- Most Grant PUD rate structures overallocated energy costs and under allocate delivery and fixed costs.
- Fixed charges, especially for large power customers (Rate 7 and above), are significantly below cost-of-service..



[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026. The modified rate structure is not comparable to 2025 revenue collected

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Charges: large power customer fixed

Results Summary

Large customer fixed charges are significantly below Grant PUD's cost to serve and significantly less on a $/kWh basis than small users. Misalignment creates a short-term revenue risk when a customer temporarily reduces usage.

Increasing the basic cost to align with cost-of-service results would be a significant increase to minimum monthly payments but have a minimal impact on bills due to the volume of kWh and kW.

Rate	Current Monthly $	COSA Monthly $	% Bill Change
Rate 7 Lg. General Service	$166.63	$459.61	+3.63%
Rate 14 Industrial	$726.44	$5,530.83	+4.00%
Rate 15 Large Industrial	$1,061.08	$17,260.63	+3.60%
Rate 16 Ag Industrial	$726.44	$4,230.02	+4.33%
Rate 17 Evolving Industry	$1,000.00	$3,038.56	+2.72%
Rate 20 HD Compute	$1,061.08	$26,076.17	+5.09%

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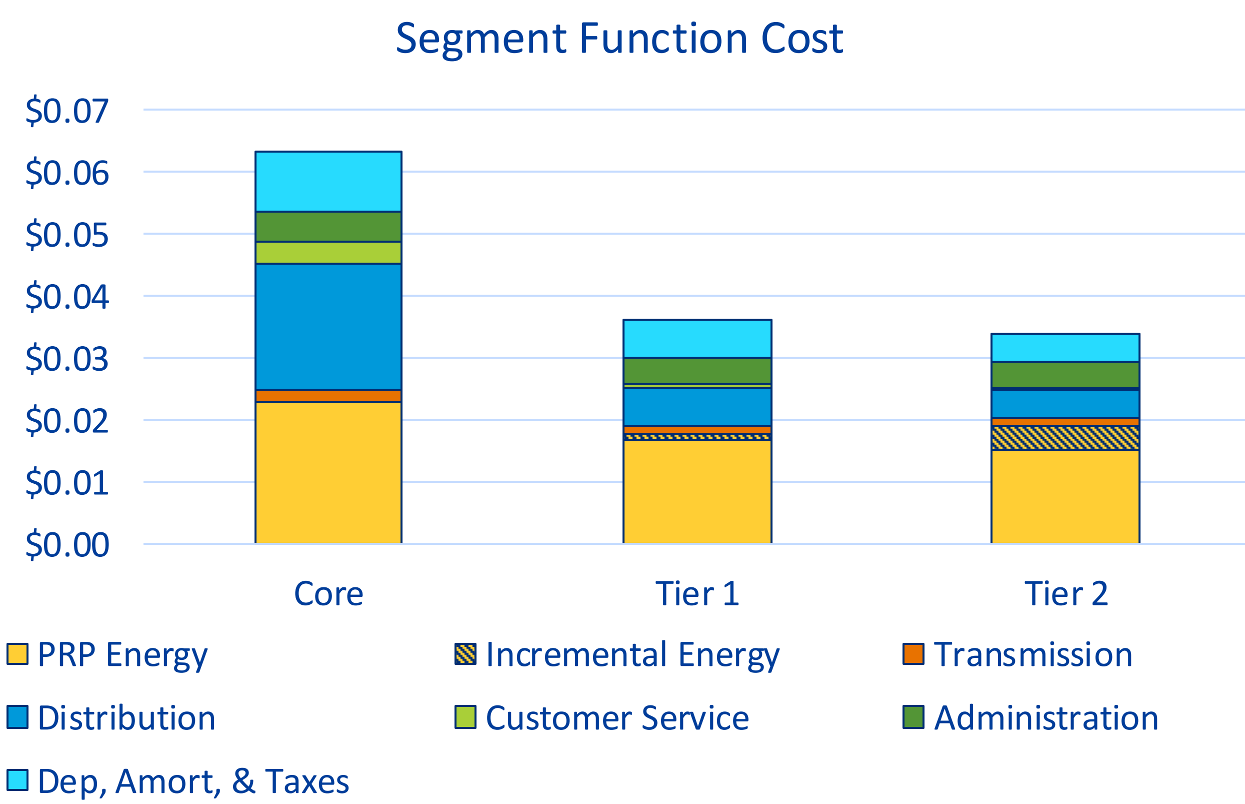
Functions Perspective

Results Summary

The Function Perspective highlights the cost to serve customer rate classes by utility function (energy supply, transmission, distribution, etc.).

- Preferential access to power from the Priest Rapids Project provides initial lower Core power supply costs. However, line losses and peak capacity characteristics of Core rate classes create higher costs within the COSA model.
- The dispersed nature of Core customers causes significantly higher distribution and depreciation costs compared to Tier 1 and Tier 2 customers.
- Similarities between Tier 1 and Tier 2 power delivery and customer service + admin costs indicate opportunity to simplify rate structures.



Grant PUD

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7

Detailed Results

Details by Segment and Class

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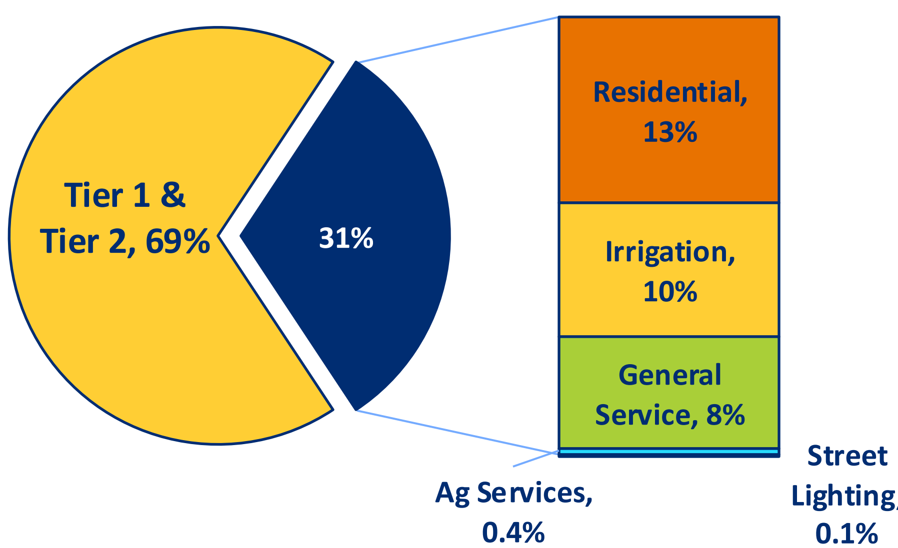
Core Customer Segment

Detailed Results

Core customers are responsible for 31% of Grant PUDs energy sales.

Rate	Defining Characteristic
Rate 1 Residential	Single family, individual apartments, manufactured homes and/or farmhouses.
Rate 2 General Service	Commercial and light industrial buildings using below 500 kW.
Rate 3 Irrigation	Irrigation pumping loads not exceeding 2,500 horsepower.
Rate 3B Ag Service	Agricultural production and storage prior to first sale of product.
Rate 6 Street Lighting	Grant PUD owned streetlighting serving.

Core Retail Energy Sales



Grant PUD

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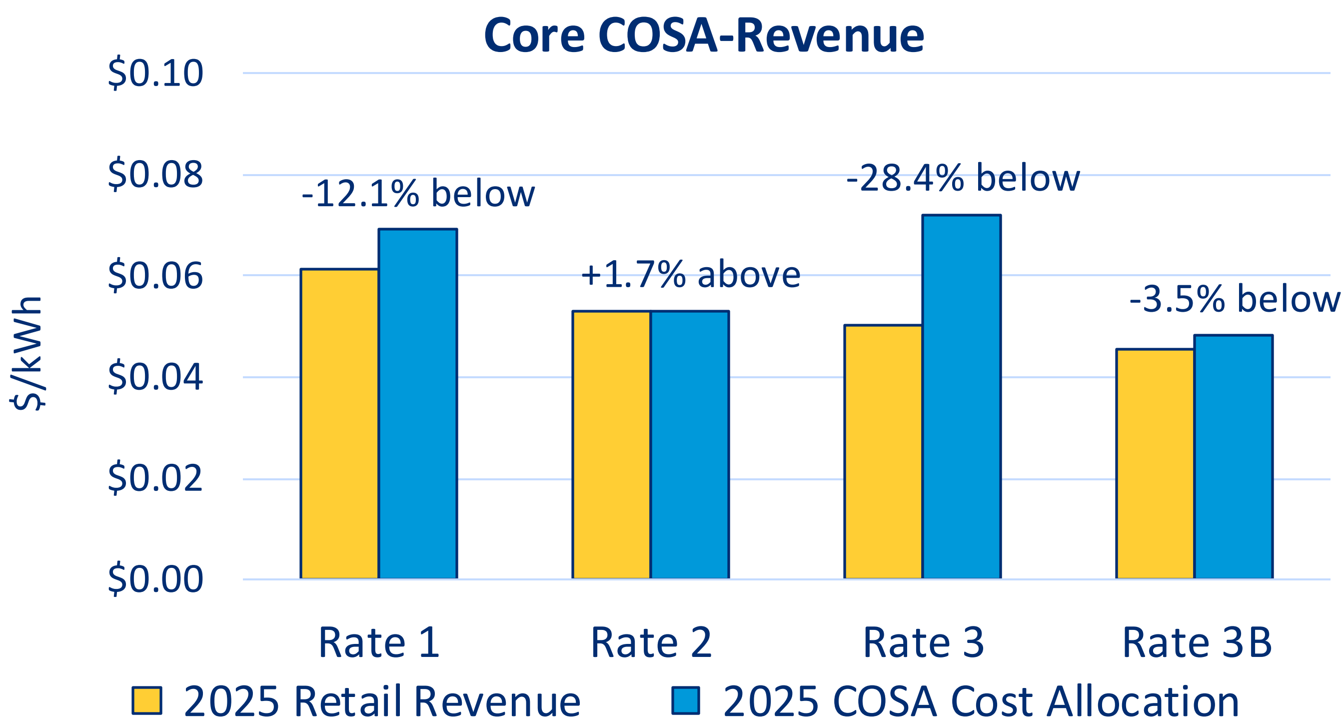
Core: COSA-Revenue Perspective

Results



- Irrigation (Rate 3) and Residential (Rate 1) cost-to-serve is significantly higher (28.4%) and (12.1%) than retail revenue. Creates risk to irrigation and residential customers if other rate classes or wholesale activities are unable to cover Grant PUD's revenue requirement.
- Ag Service (Rate 3B) and General Service (Rate 2) +/- 10% of the cost-to-serve.

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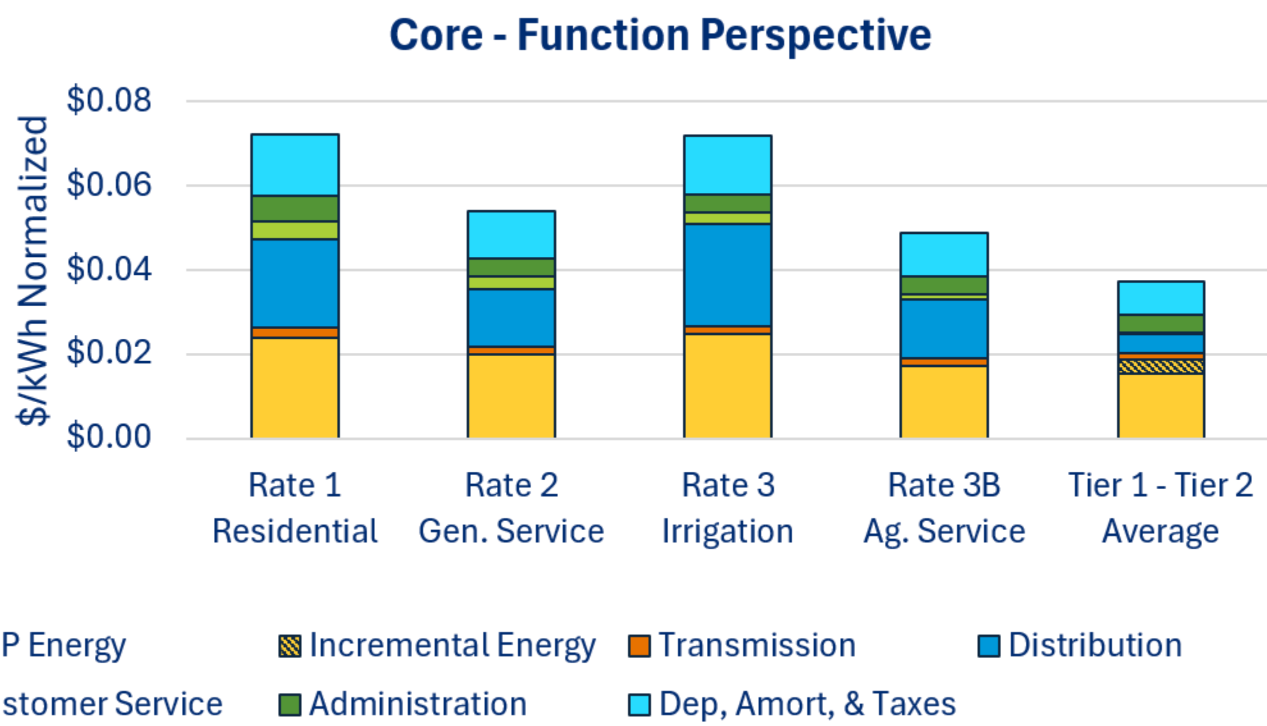
Core: Function Perspective

Results



- **Power Supply**: Core rate classes incur lower power supply costs than Tier 1 and Tier 2 rate classes through an Unbundled Power Supply Methodology. However, line losses and capacity differences allocate more costs to Core vs. non-Core resulting in higher overall costs. Variance *between* Core customer rate classes occurs because of peak load alignment during WRAP capacity months.
- **Power Delivery:** Core rate classes incur higher power delivery costs due to line miles and low load factors. Rates 2 and 3B power delivery costs are lower than Residential and Irrigation because businesses are concentrated in urban areas.
- **Customer Service + Admin**: Core customer classes incur significantly higher customer service and administrative costs than Tier 1 and Tier 2 customers due to volume of customers.

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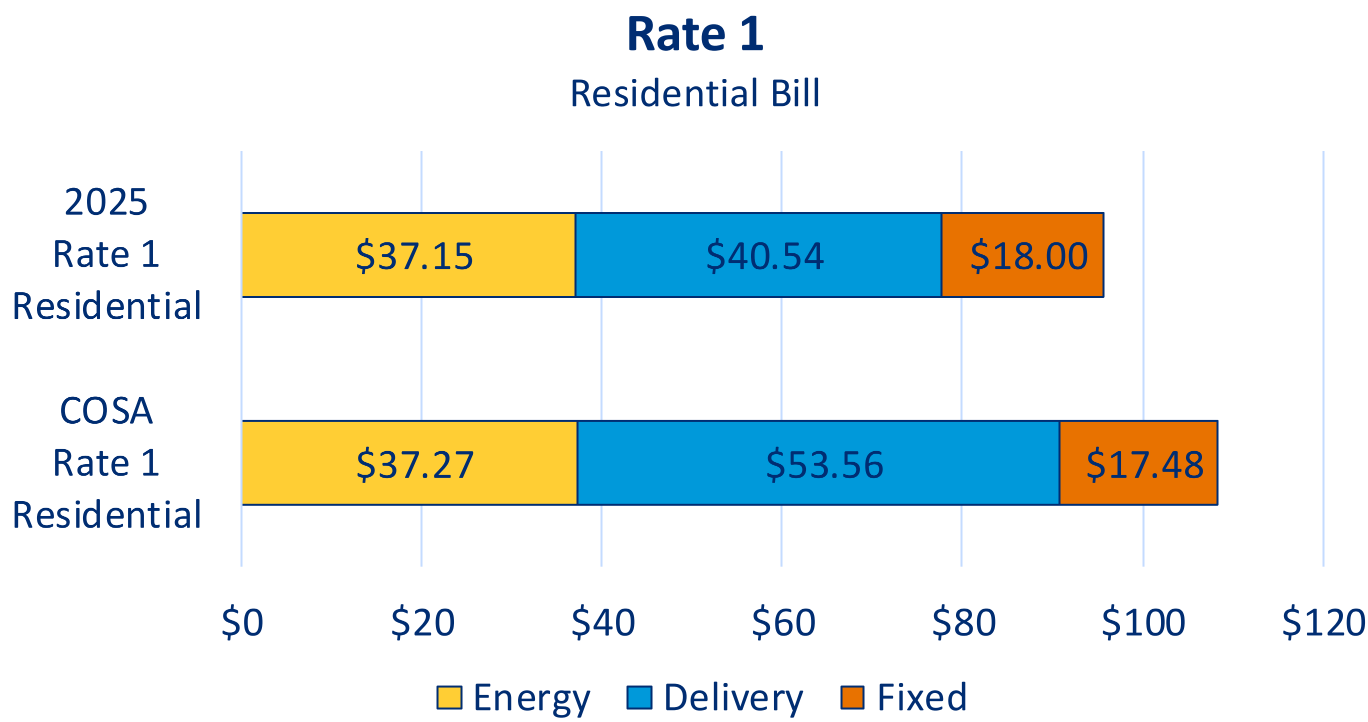
Rate 1 Charges Perspective

Results

Current bill structure poses little risk

- Energy and fixed portions of the bill are structured similarly to Grant PUD's cost-to-serve.
- Delivery is much lower than cost to serve – likely due to residential customers paying 12% below cost-of-service.



Residential	Energy	Delivery	Fixed
COSA	$0.02394/kWh	$0.03440/kWh	$0.58/day
2025 Rates[1]	$0.02386/kWh	$0.02604/kWh	$0.60/day
Billing Assumptions	1,557 kWh	1,557 kWh	30 days

[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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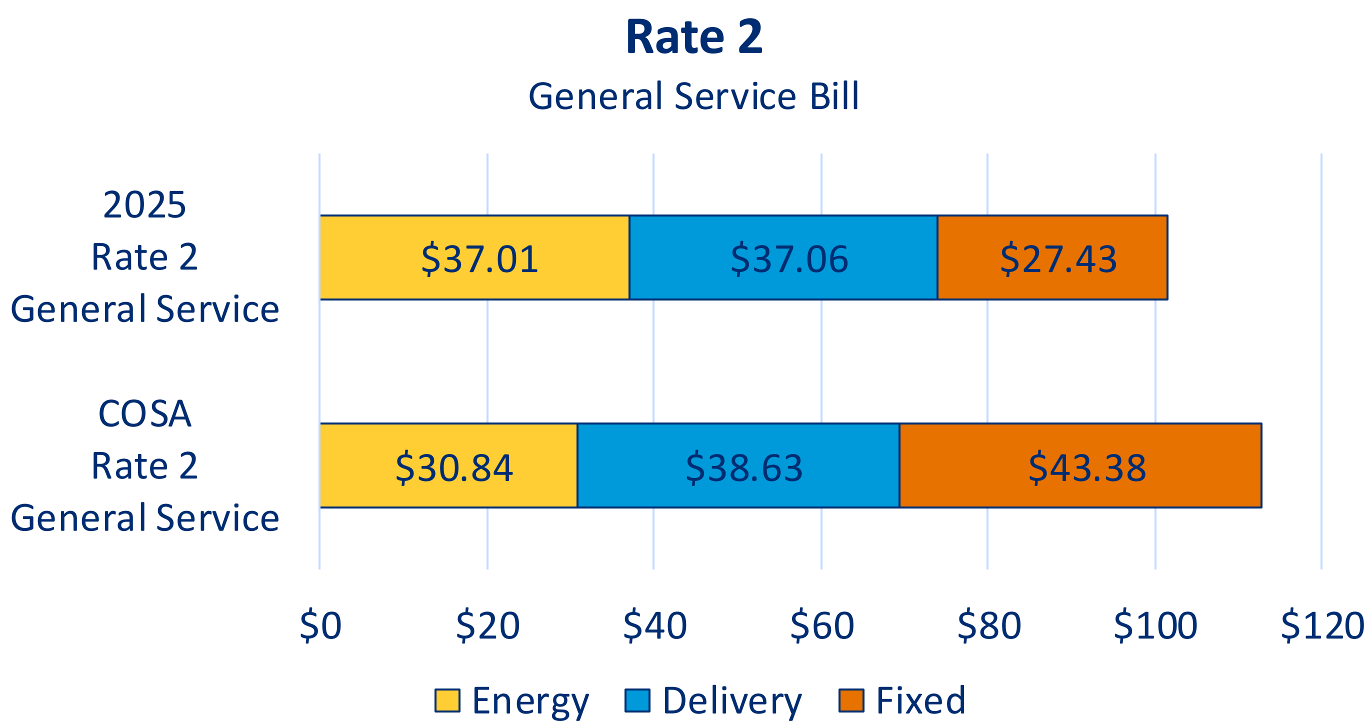
Rate 2 Charges Perspective

Results

Rate structure treats customers differently

- Current billing structure favors smaller customers (see discussion in Results Summary section).



General Service	Energy	Delivery	Fixed
COSA	$0.01989/kWh	$0.02491/kWh	$1.45/day
2025 Rates[1]	$0.02386/kWh	$0.02389/kWh	$0.092/day $0.77/day 1 phase $1.5/day 3 phase
Billing Assumptions	1,551 kWh	1,551 kWh	30 days

[1] 2025 rate structure was modified to simulate the Unbundled power cost methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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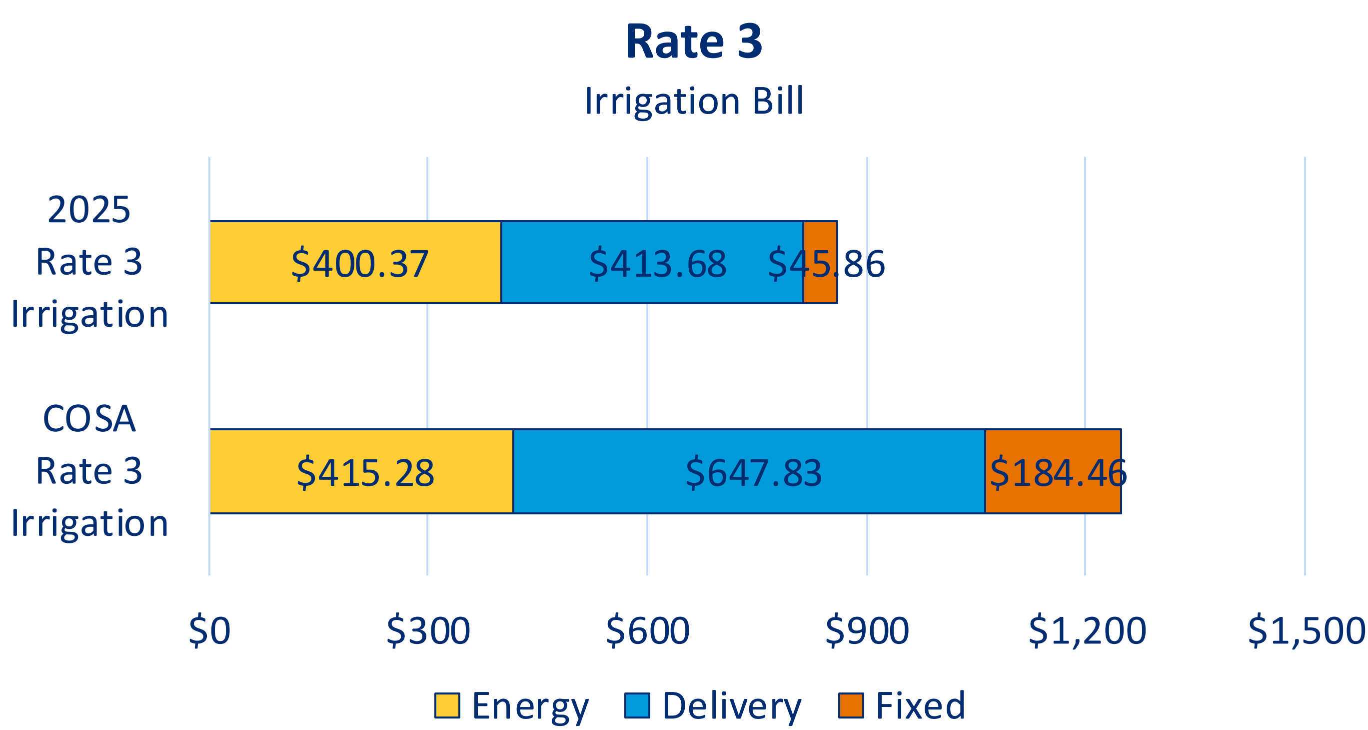
Rate 3 Charges Perspective

Results

Current bill structure creates additional risk

- Fixed costs are ~4x lower than the cost to provide service.
- Delivery costs are spread between horsepower capacity and kWh
- While rate class is below cost-of-service, shifting costs from delivery to fixed would increase revenue stability.



Irrigation	Energy	Delivery	Fixed
COSA	$0.02475/kWh	$6.61/hp	$184.46/month April – October
2025 Rates[1]	$0.02386/kWh	$4.22/hp $2.93/hp first 75 $2.69/hp above 75 $0.00790/kWh	$45.86/mo $32.22/mo 1 phase $46.00/mo 3 phase April - October
Billing Assumptions	16,780 kWh	98 hp	1 month

[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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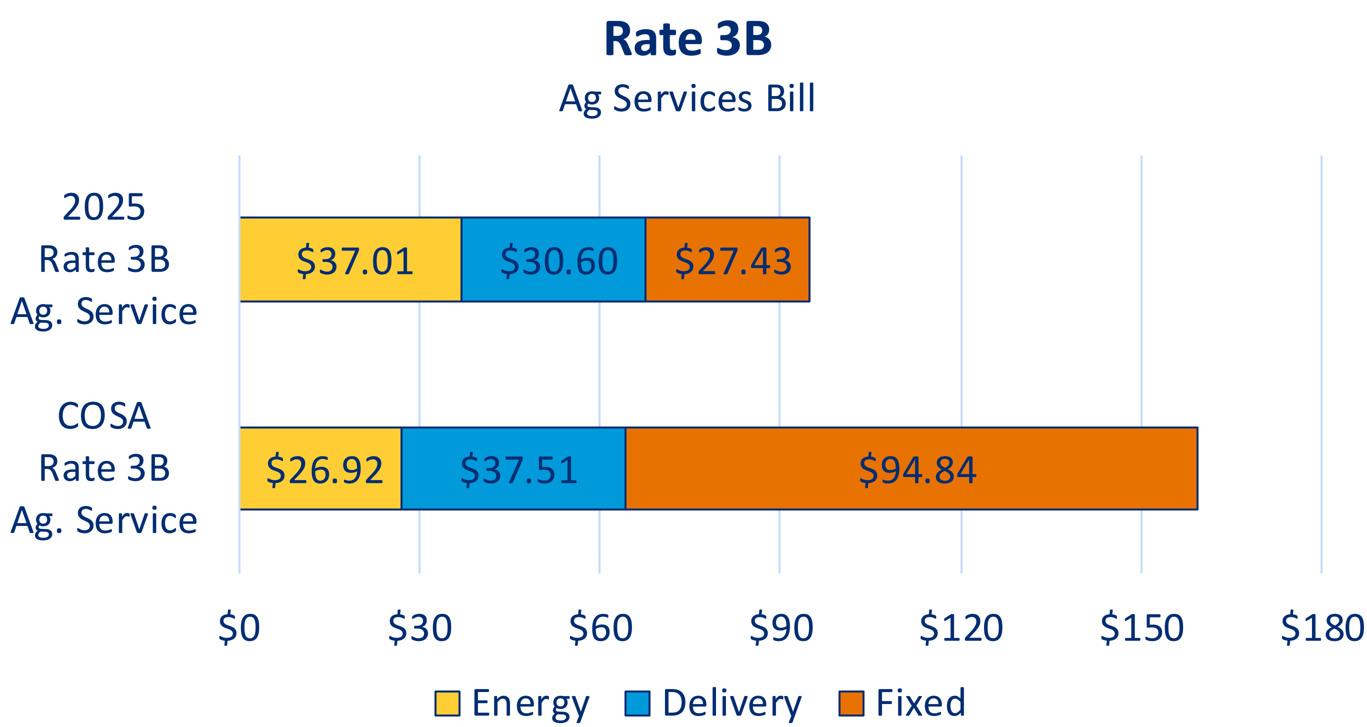
Rate 3B Charges Perspective

Results

Rate class was active six months, distorting fixed charge results.



Ag Services	Energy	Delivery	Fixed
COSA	$0.01736/kWh	$0.02418/kWh	$3.16/day
2025 Rates[1]	$0.02386/kWh	$0.01973/kWh	$0.091440/day $0.80/day 1 phase $1.19/day 3 phase
Billing Assumptions	1,551 kWh	1,551 kWh	30 days

[1] 2025 rate structure was modified to simulate the Unbundled power cost methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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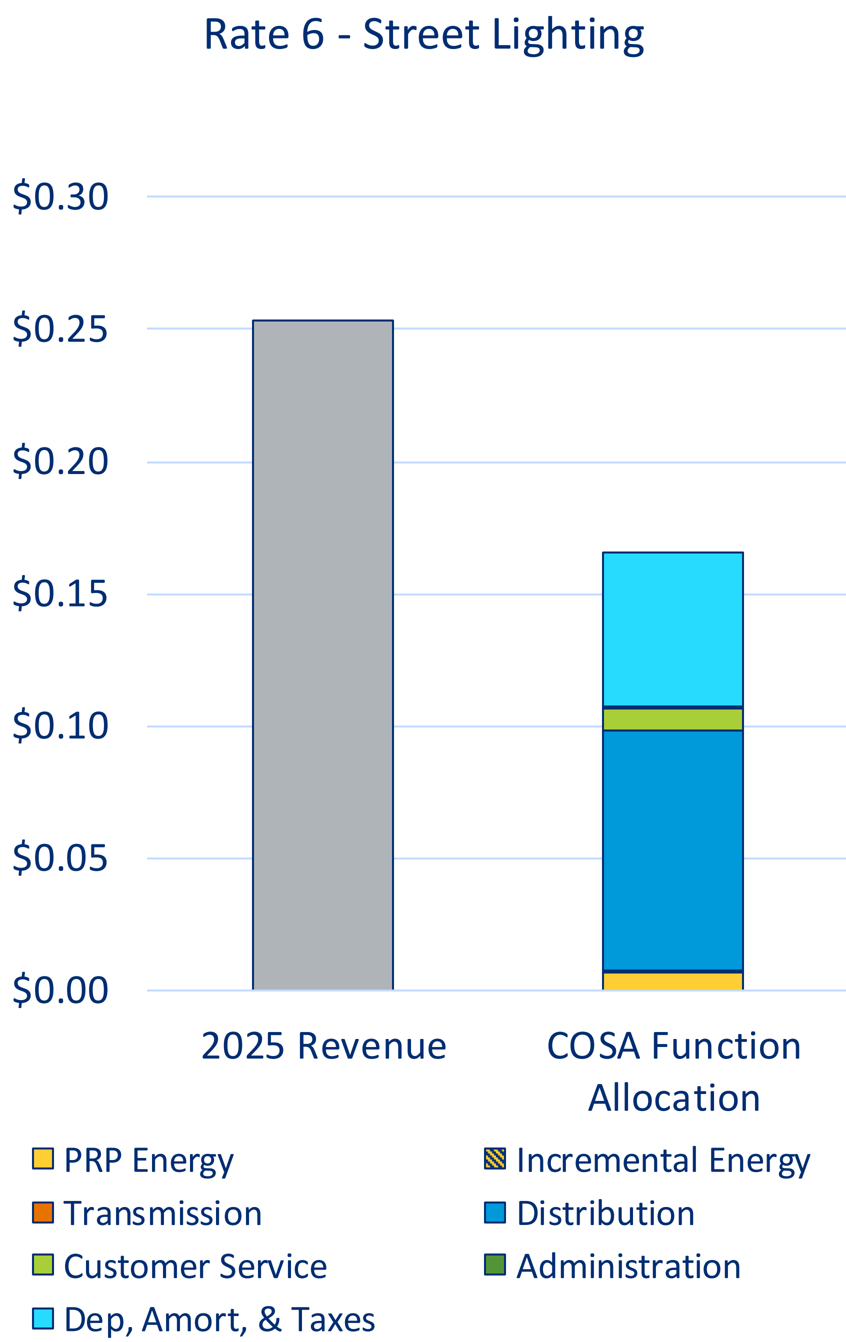
Rate 6 Outlier Analysis

Results

Rate 6 applies to a small number of Grant PUD owned streetlights.

- Customers pay a fixed cost per streetlight.
- Rate class is small, less than 1% of Core load.
- Staff believe costs are underreported and COSA results are not accurate.
- Recommend additional research after higher priority projects are complete.



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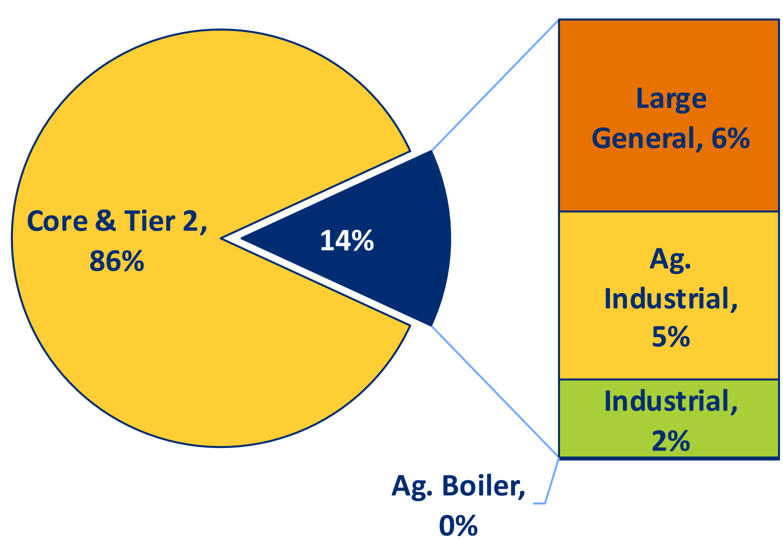
Tier 1 Customer Segment

Detailed Segment Analysis

Rate	Defining Characteristic
Rate 7 Large General	General service loads between 200 KW and 5,000 kW
Rate 14 Industrial0.8	Industrial loads between 5 MW and less than 10 MW
Rate 16 Ag Food Processing	Loads greater than 5 MW and less than 15 MW for Ag Food Processing
Rate 85 Ag Boiler	Electric boiler serving Ag Food processing

Tier 1 customers are responsible for 14% of Grant PUDs energy sales.

Tier 1 Retail Energy Sales



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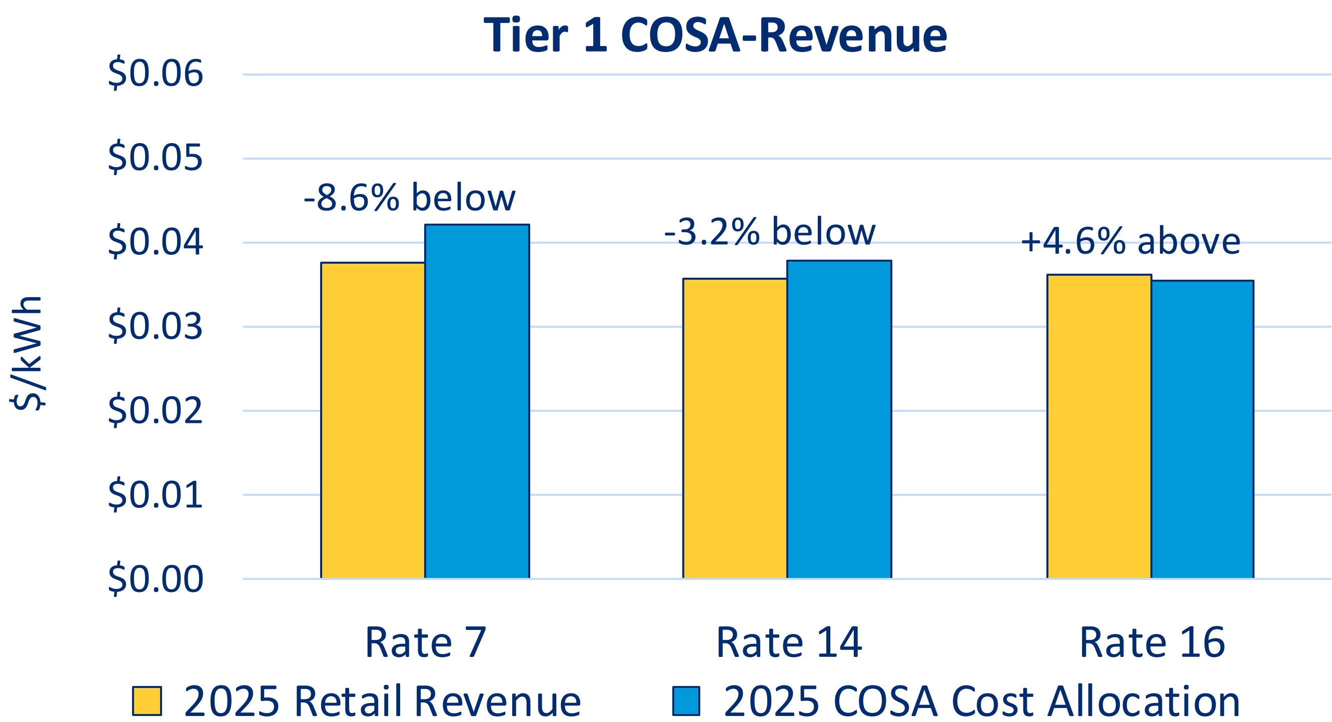
Tier 1: COSA-Revenue Perspective

Results



- All Tier 1 rate classes are +/- 10% of the cost-to-serve.
- Rate 16 higher costs driven by higher customer service costs compared to Rates 7 and 14 due to ratio of kWh fixed customer service and administration costs.

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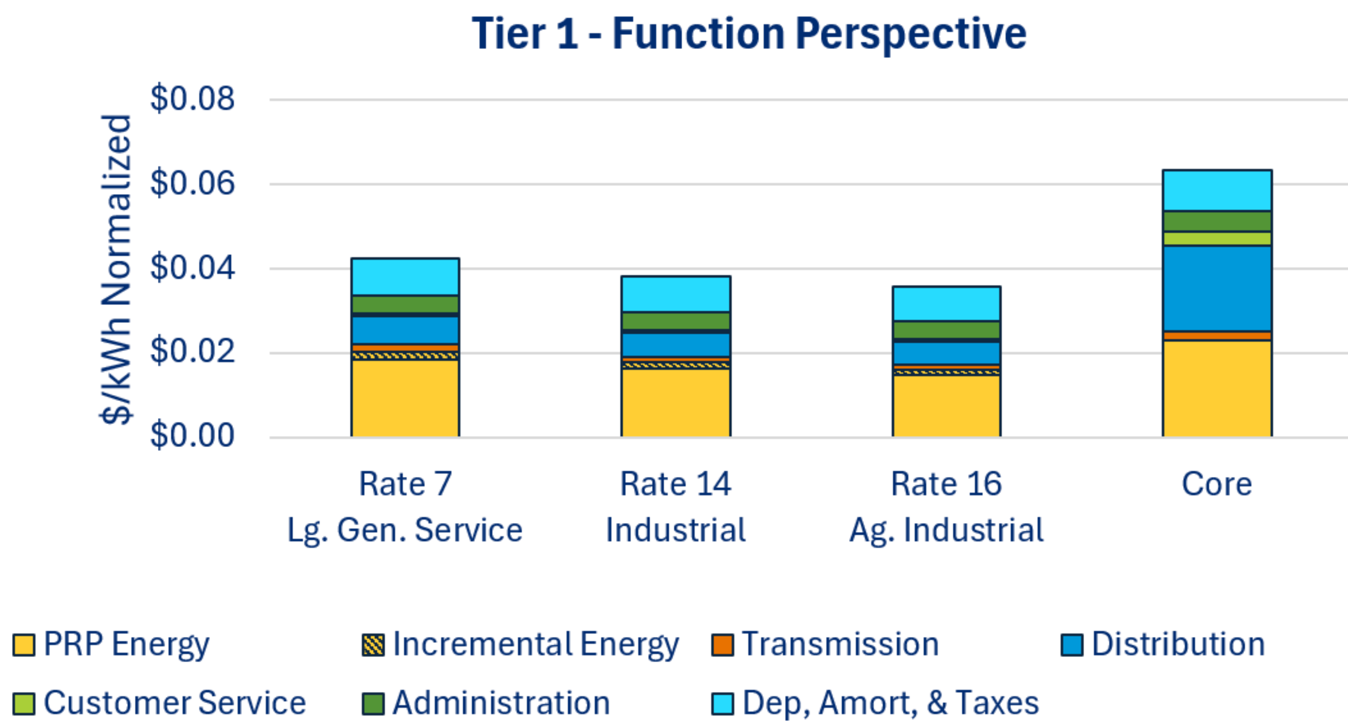
Tier 1: Function Perspective

Results



- **Power Supply**: Power Supply Charge is consistent between Rate 14 and 16 with Rate 7 having a slightly higher power supply charge. This is consistent across the utility industry where larger demand customers have lower energy costs.
- **Power Delivery:** Tier 1 rate classes incur lower Power Delivery costs than Core customers because they are generally located in more concentrated service areas, requiring less distribution infrastructure per unit of load.
- **Customer Service + Admin**: Tier 1 customers incur substantially lower Customer Service and Administrative costs than Core customers due to lower customer volumes and reduced service demands. Rate 16 (Ag. Industrial) has higher customer service allocations due to model weighting which is likely underreported when normalized by kWh sales.

Grant PUD

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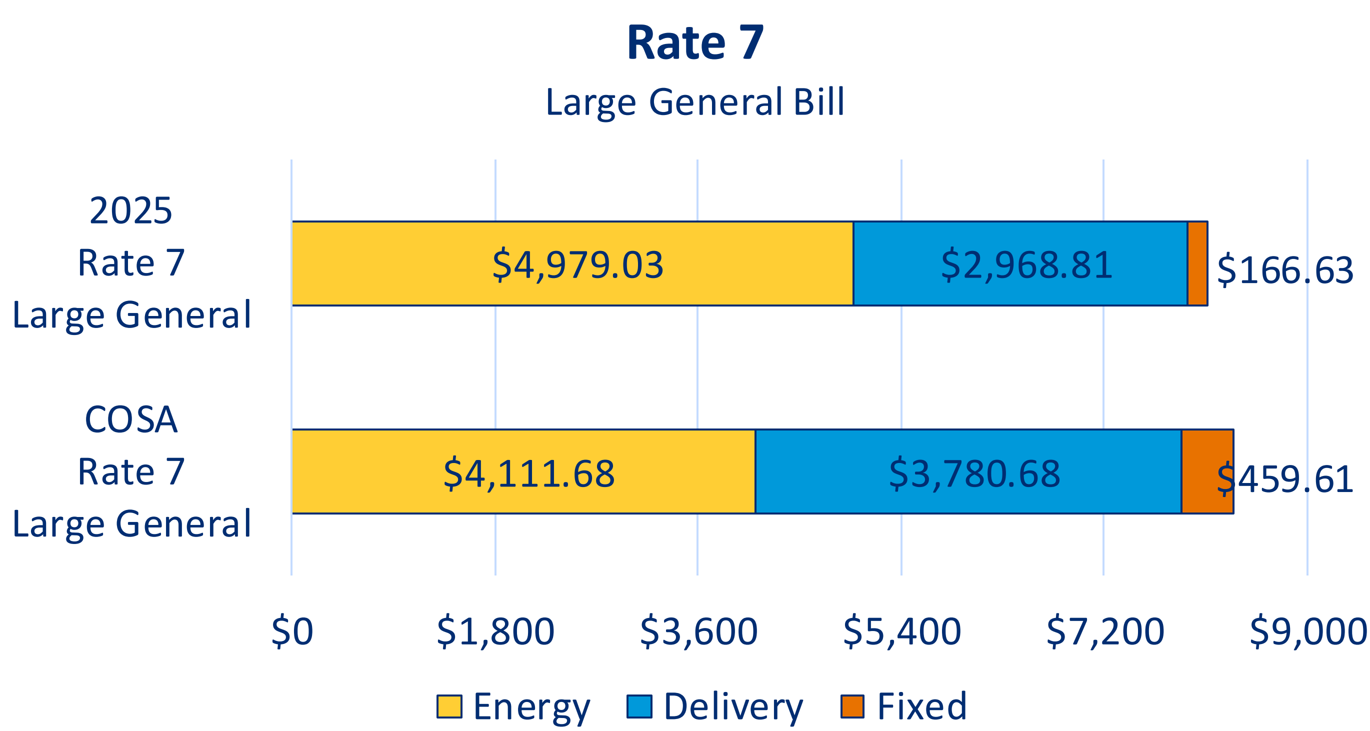
Rate 7 Charges Perspective

Results

Current bill structure poses little risk to Grant PUD

- Energy charge is above Grant PUD's cost-to-serve.
- Delivery and fixed charge are lower than cost to serve.
- Grant PUD should consider increasing fixed charge to better align with cost-of-service.



Large General	Energy	Delivery	Fixed
COSA	$0.02032/kWh	$7.09/kW	$459.61/mo
2025 Rates[1]	$0.02460 kWh $0.02386/kWh PRP $0.00074/kWh Inc	$5.57/kW	$166.63/mo
Billing Assumptions	202,370 kWh	533 kW	1 month

[1] 2025 rate structure was modified to simulate the Unbundled Power supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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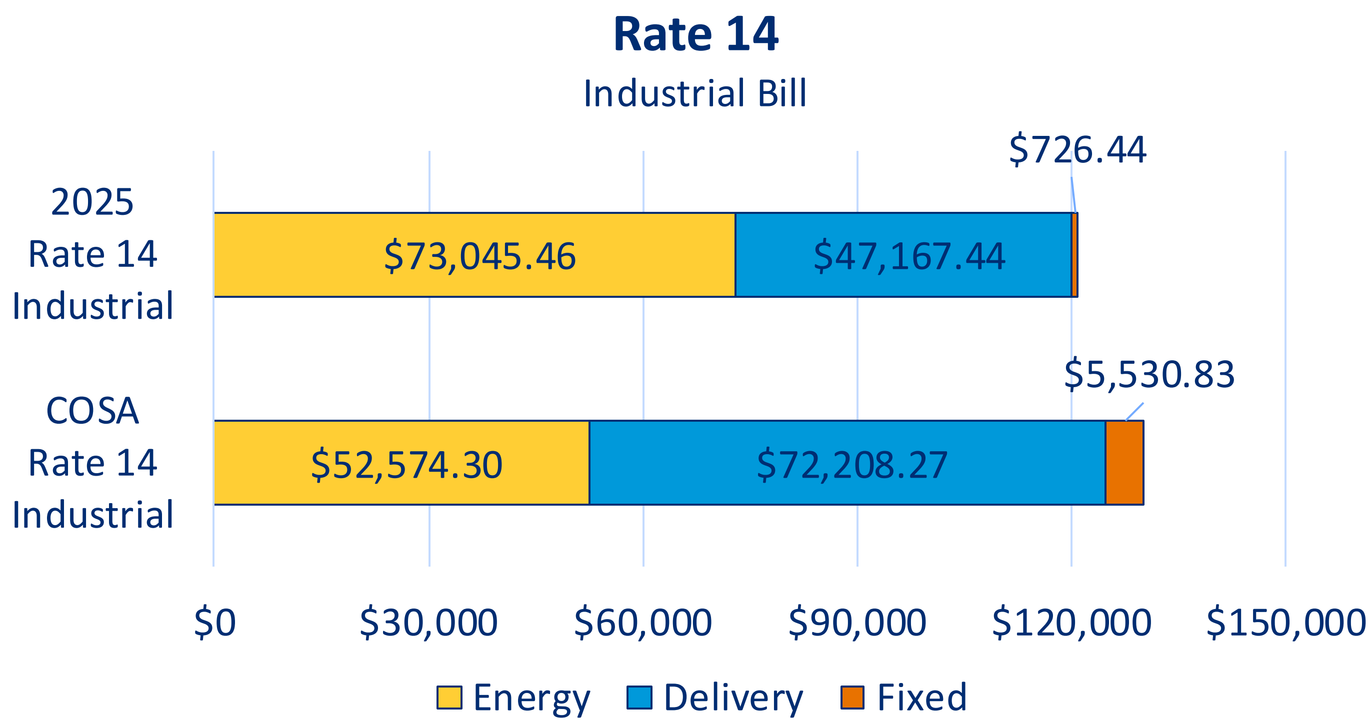
Rate 14 Charges Perspective

Results

Little risk posed by current bill structure

- Energy charge is above Grant PUD's cost-to-serve.
- Delivery and fixed charge are lower than cost to serve.
- Grant PUD should consider increasing fixed charge to better align with cost-of-service.



Industrial	Energy	Delivery	Fixed
COSA	$0.01771/kWh	$9.12/kW	$5,530.83/mo
2025 Rates[1]	$0.02460 kWh $0.02386/kWh PRP $0.00074/kWh Inc	$5.96/kW	$726.44/mo
Billing Assumptions	2,968,896 kWh	7,914 kW	1 month

Grant PUD

[1] 2025 rate structure was modified to simulate the Unbundled power cost methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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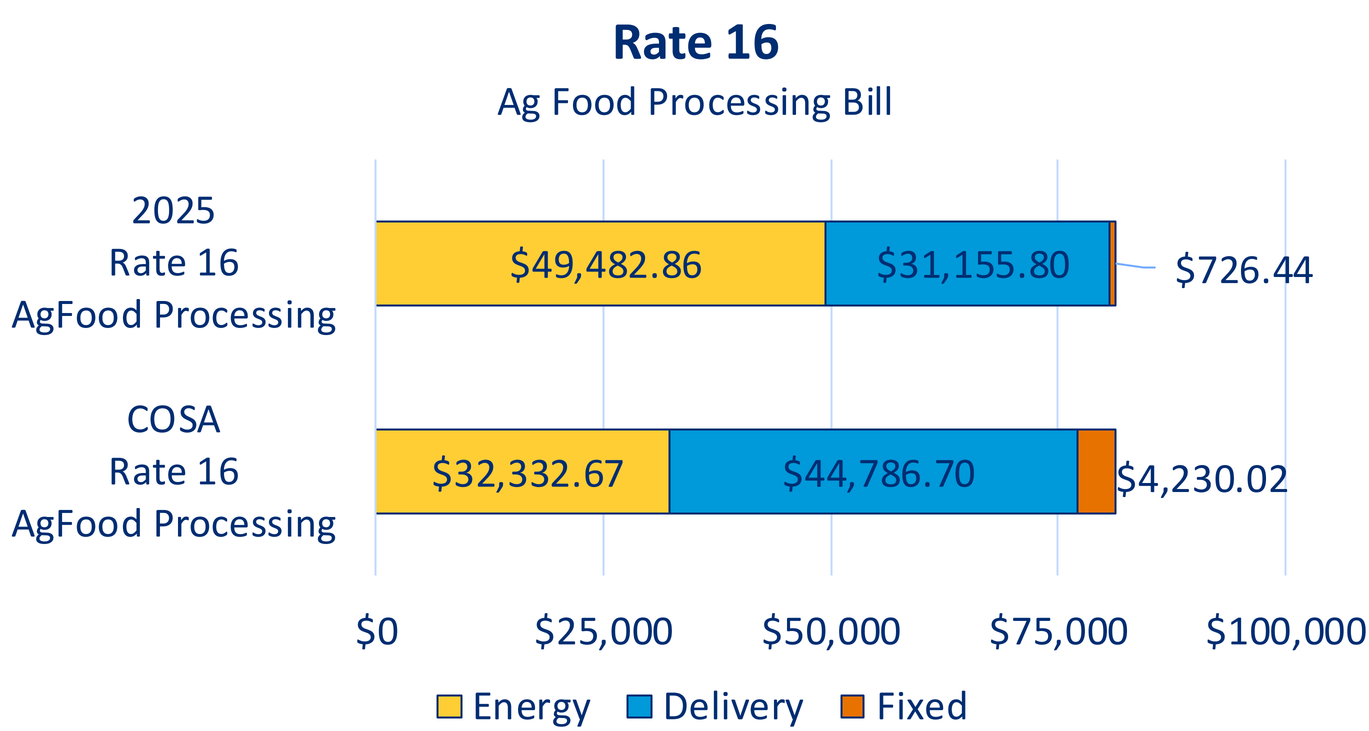
Rate 16 Charges Perspective

Results

Current bill structure poses little risk

- Energy charge is above Grant PUD's cost-to-serve.
- Delivery and fixed charge are lower than cost to serve.
- Grant PUD should consider increasing fixed charge to better align with cost-of-service



Ag Food Processing	Energy	Delivery	Fixed
COSA	$0.01608/kWh	$8.60/kW	$4,230.02/mo
2025 Rates[1]	$0.02460/kWh $0.02386/kWh PRP $0.00074/kWh Inc	$5.98/kW	$726.44/mo
Billing Assumptions	2,011,206 kWh	5,210 kW	1 month

[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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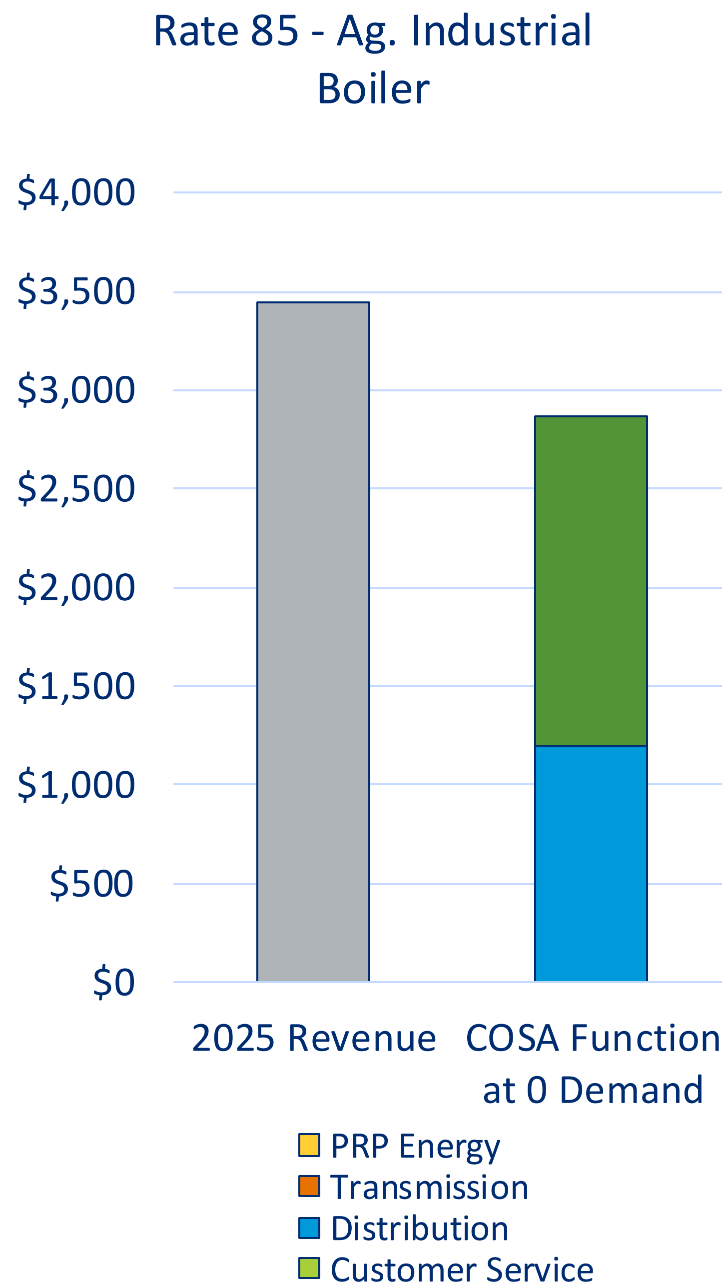
Rate 85 Outlier Analysis

Results

Rate 85 applies to a single customer with a boiler that supports agricultural processing.

- Customer maintains boiler equipment for fuel switching. Currently no plans to energize the boiler.
- Zero consumption and demand distort cost allocation.
- $150k of depreciation not allocated via the COSA model and should be rolled into the fixed cost.
- Up to $200k of transmission and distribution costs not allocated via the COSA model and could be rolled into the fixed cost.
- Recommend moving to Tier 2, increasing 2027 fixed charges, and exploring additional revenue collection options.



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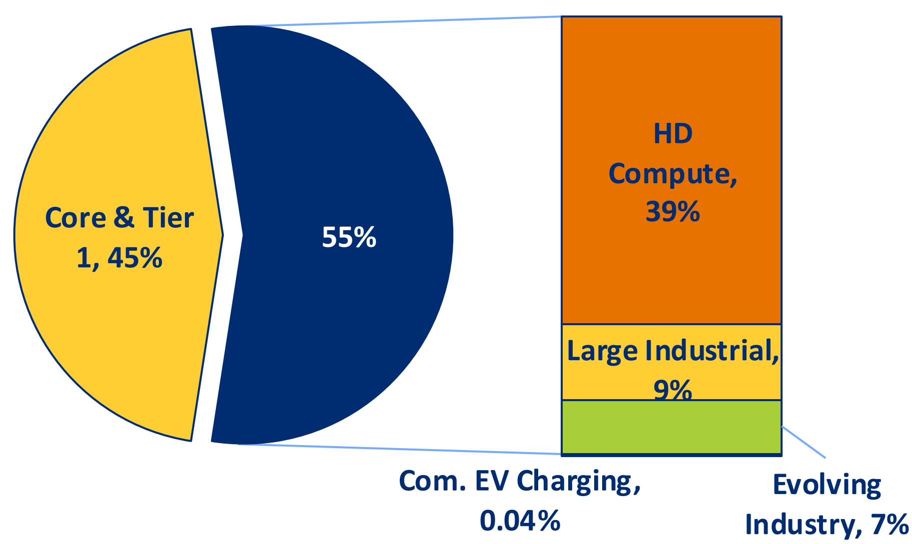
Tier 2 Customer Segment

Detailed Segment Analysis

Tier 2 customers are responsible for 55% of Grant PUDs energy sales.

Rate	Defining Characteristic
Rate 15 Large Industrial	Industrial loads greater than or equal to 10 MW
Rate 17 Evolving Industry	Applied to the accounts of Crypto Currency loads
Rate 19 EV Charging	Level 3 (or above) fast charging stations with monthly loads of no more than 3,000 kW Billing Demand at an individual location
Rate 20 High Density Compute	Any facility where energy is used for data processing, cloud computing

Tier 2 Retail Energy Sales



Grant PUD

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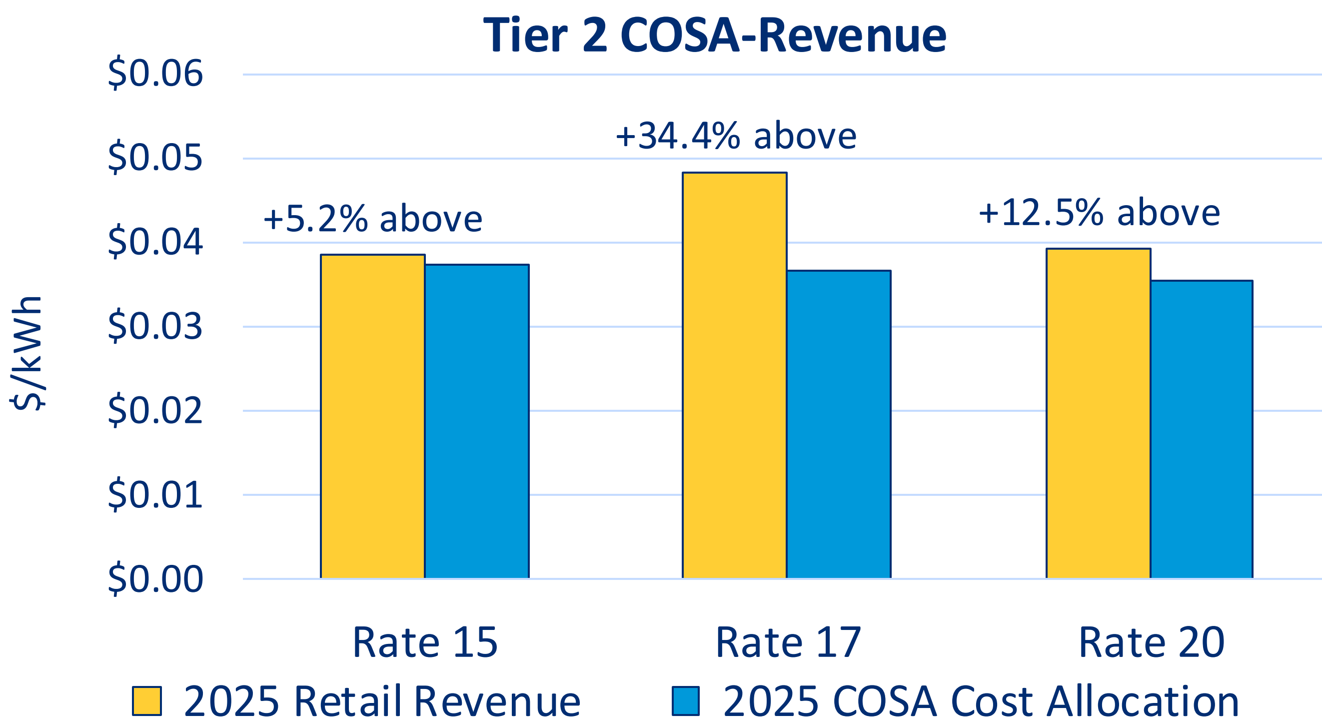
Tier 2: COSA-Revenue View

Results



All Tier 2 rate classes recover more revenue than their allocated cost-of-service.

- Rate 15 (Large Industrial) are 5.2% above cost-of-service and remain within the ±10% industry guideline.
- Rate 17 (Evolving Industry) and Rate 20 (High Density Compute) exceed the typical industry guideline of ±10%, with revenues 34.4% and 12.5% above cost-of-service.

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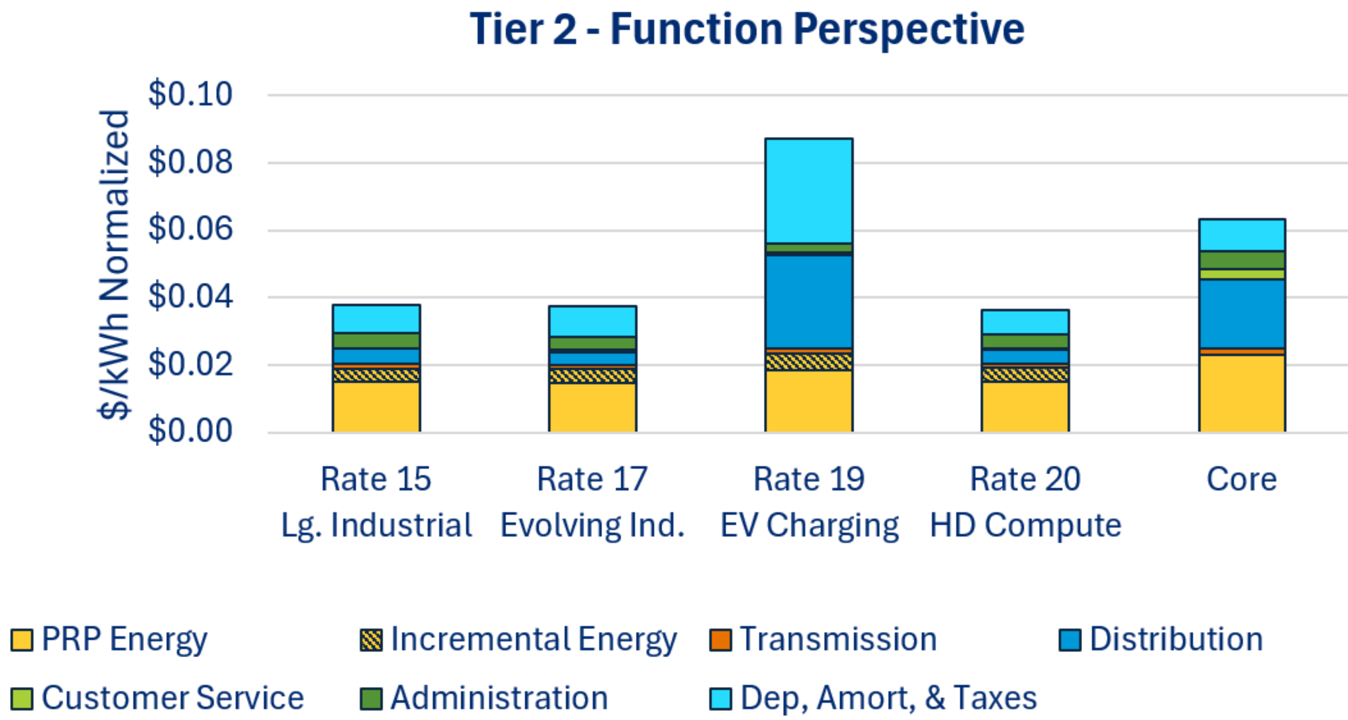
Tier 2: Function Perspective

Results



- **Power Supply**: Power Supply costs are generally lower for Tier 2 rate classes due to lower line losses and coincident peaking during WRAP months despite paying incremental power cost.
- **Power Delivery:** Most Tier 2 rate classes have low Power Delivery costs due to large size, geographic concentration, and high load factor.
- **Customer Service + Admin**: Tier 2 rate classes incur substantially lower total Customer Service + Admin costs than Core customers due to low customer count.

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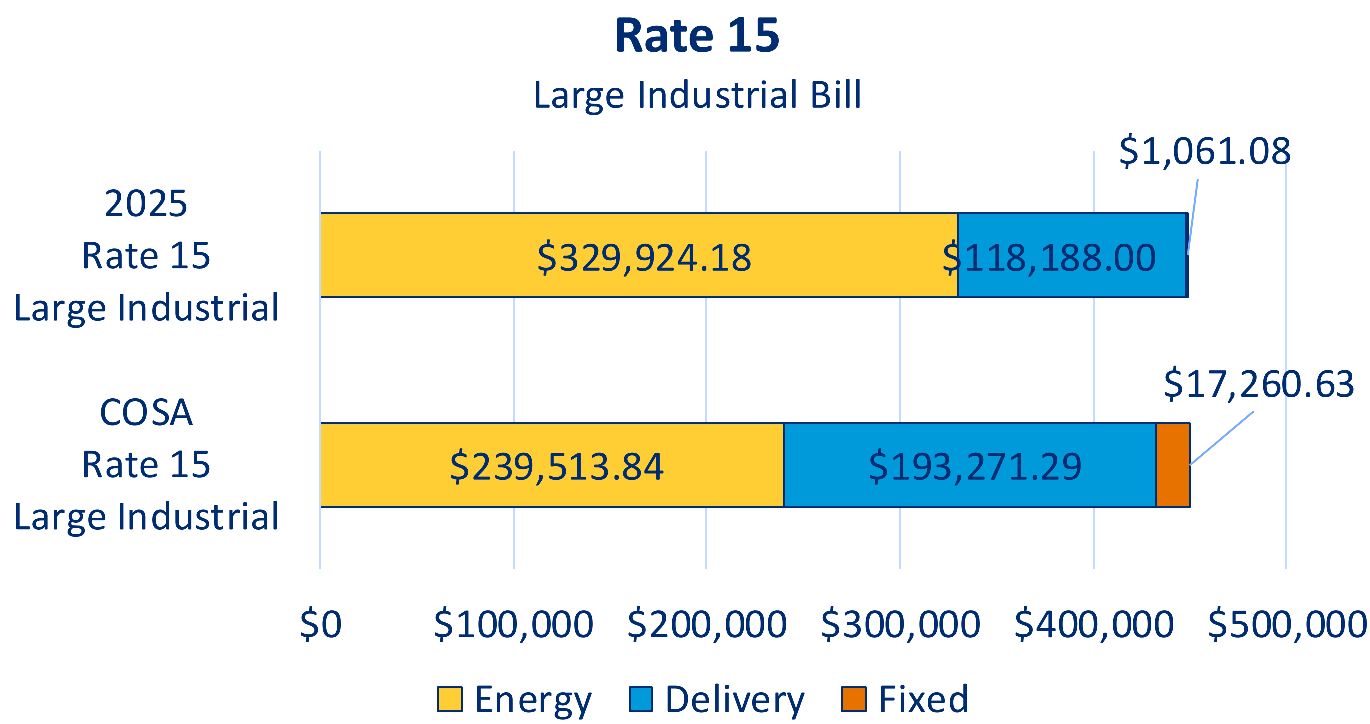
Rate 15 Charges Perspective

Results

Current bill structure poses little risk

- Energy charge is above Grant PUD's cost-to-serve.
- Delivery and fixed charge are lower than cost to serve.
- Grant PUD should consider increasing fixed charge to better align with cost-of-service results.



Large Industrial	Energy	Delivery	Fixed
COSA	$0.01907/kWh	$9.86/kW	$17,260.63/mo
2025 Rates[1]	$0.02627/kWh $0.02386/kWh PRP $0.00241/kWh Inc	$6.03/kW	$1,061.08/mo
Billing Assumptions	12,560,336 kWh	19,600 kW	1 month

[1] 2025 rate structure was modified to simulate the Unbundled power cost methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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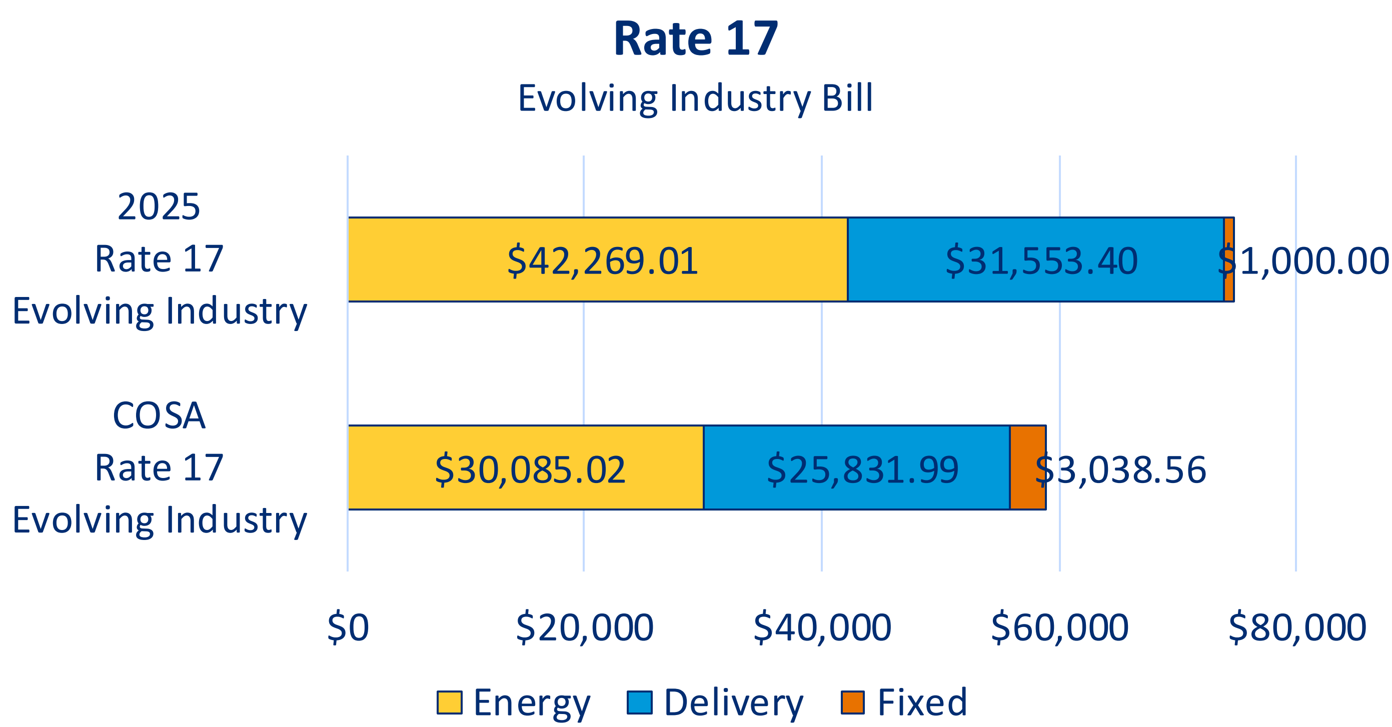
Rate 17 Charges Perspective

Results

No risk posed by rate structure

- Grant PUD should roll Rate 17 into Rate 20 (High Density Compute)



Evolving Industry	Energy	Delivery	Fixed
COSA	$0.01870/kWh	$10.56/kW	$3,038.56/mo
2025 Rates[1]	$0.02627/kWh $0.02386/kWh PRP $0.00241/kWh Inc	$12.90/kW	$1,000.00/mo
Billing Assumptions	1,609,197 kWh	2,446 kW	1 month

[1] 2025 rate structure was modified to simulate the Unbundled Power Supply Methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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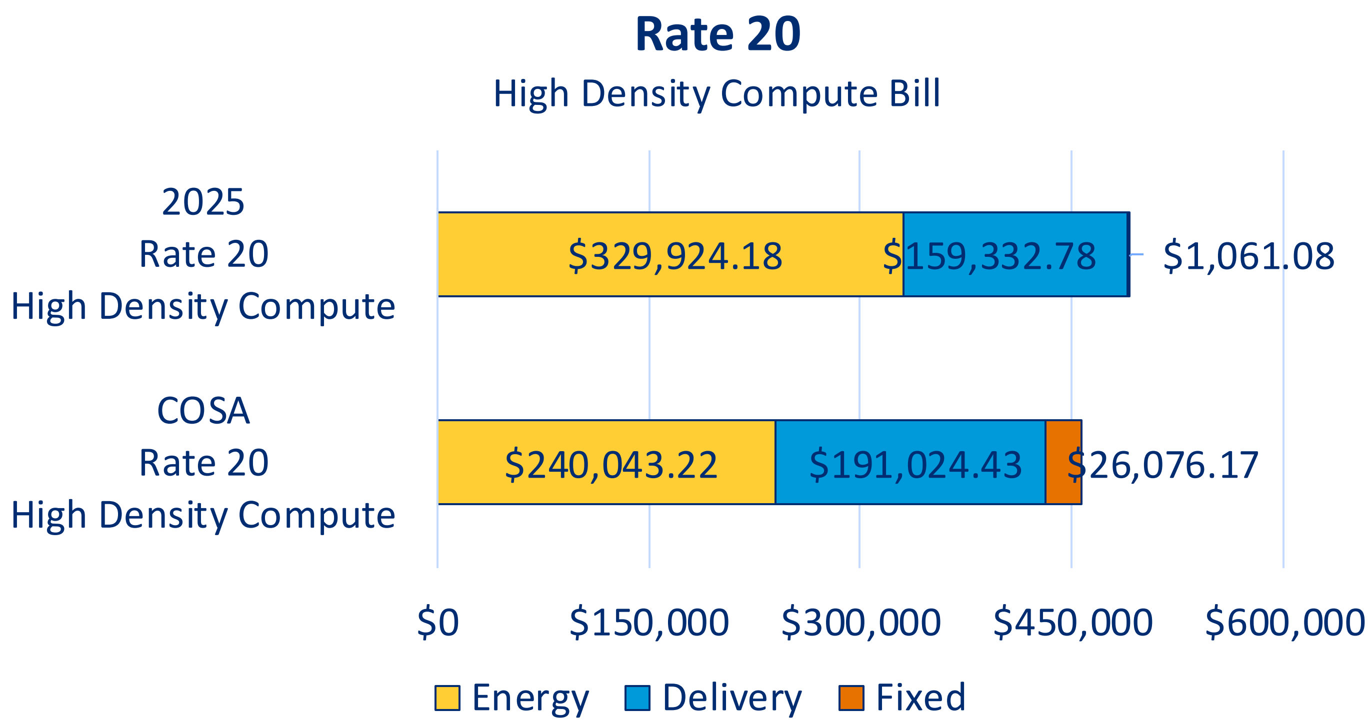
Rate 20 Charges Perspective

Results

Current bill structure poses little risk

- Energy charge is above Grant PUD's cost-to-serve.
- Delivery and fixed charge are lower than cost to serve.
- Grant PUD should consider increasing fixed charge to better align with cost-of-service.



High Density Compute	Energy	Delivery	Fixed
COSA	$0.01911/kWh	$9.75/kW	$26,076.17/mo
2025 Rates[1]	$0.02627/kWh $0.02386/kWh PRP $0.00241/kWh Inc	$8.13/kW	$1,061.08/mo
Billing Assumptions	12,560,336 kWh	19,600 kW	1 month

[1] 2025 rate structure was modified to simulate the Unbundled power cost methodology approved by Grant PUD Commission in 2025 and implemented in 2026.

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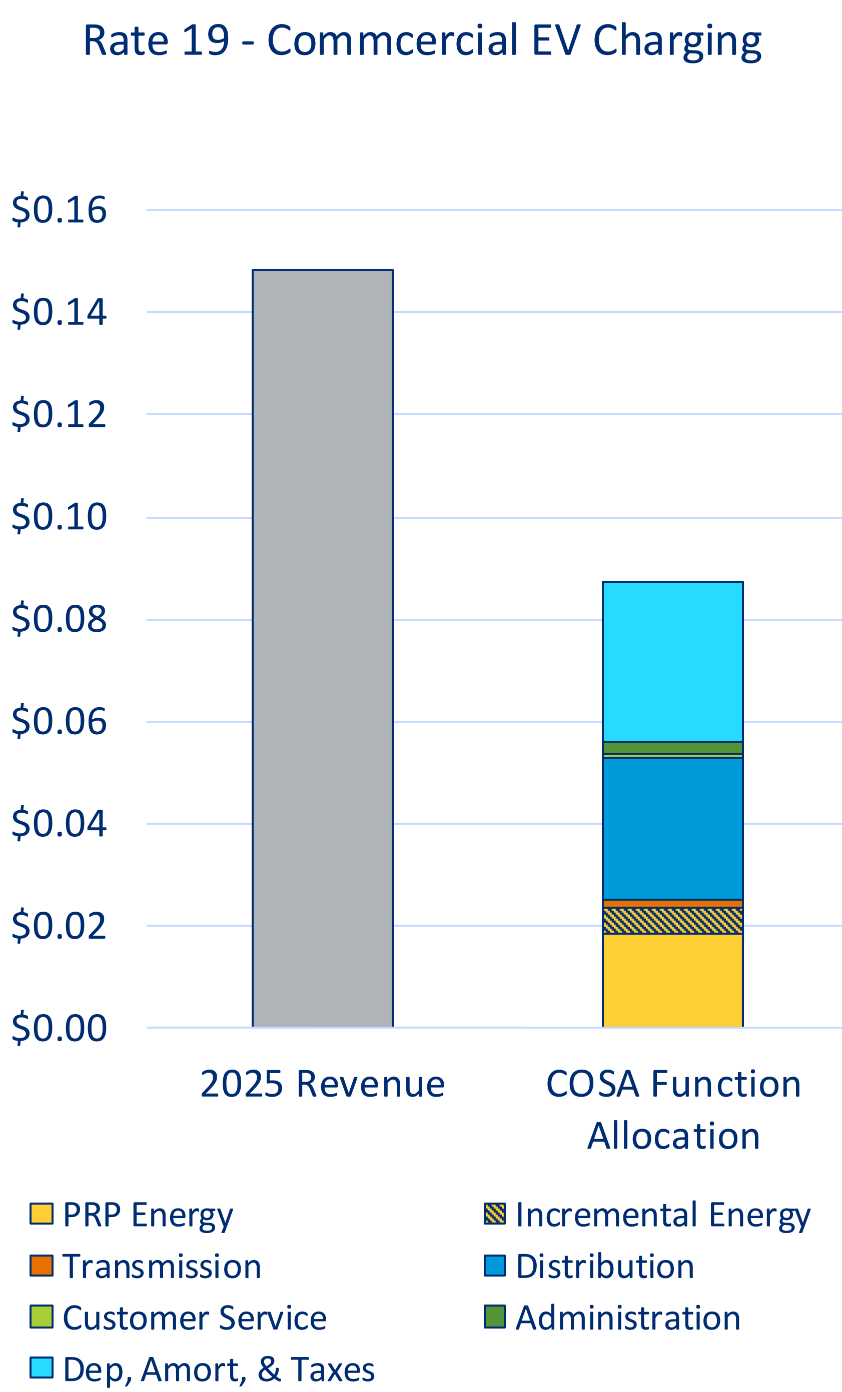
Rate 19 Outlier Analysis

Results

Rate 19 applies to commercial owned EV Charging

- Rate is structured like other industrial rates.
- EV charging has a very low load factor that distorts admin charges.
- Recommend additional research after higher priority projects are complete.



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Questions?

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Bret Hammond
Lead Financial Analyst
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Amy Pheasant
Financial Analyst
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Grant PUD

Quarterly Business Review (QBR)

Shared Services

August 18, 2026

Fallon Long, Vice President

Grant PUD

Powering our way of life.

Team

FALLON LONG
Vice President of Shared Services

JESSICA FRANKS
Executive Assistant III

BRIAN BARROWS
Senior Manager of Transportation & Facilities

CRAIG BRESSAN
Senior Manager of Safety, Security & Emergency Management

PATRICK BISHOP
Senior Manager of Supply Chain

Total Positions in Org	138
Current Headcount	126

Staff Updates:

- New: Dale Hagy-Facilities Building Maintenance Worker, Ben Hickman-Fleet Services Journeyman Tech, Terrance Haaland-Security Specialist I, Nathan Smith-Security Specialist I, AJ Glen-Warehouse Student Helper

Enterprise Balanced Scorecard

Design Standards	Warehouse Governance	Safety Concerns	Job Site Review	Interdepartmental Collaboration
% of Targeted Standards Transitioned to a Standard Design Template	*% of Stock Items Reviewed for Like Inventory*	*Measures % of Closed by Date*	*Measures % Completed vs. Established*	*Measures Service 5 Ratings*
Green	**Green**	**Green**	**Red**	**Red**

- Additional Information – Fallon will add detail form last discussion with Commission

Executive Financial Overview

JUNE 2026

O&M DIRECTS YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$4,980K	$4,908K	($71K)	-1.4%

O&M DIRECTS YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$11,535K	$11,394K	($141K)	-1.2%

LABOR YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$6,841K	$6,622K	($219K)	-3.2%

LABOR YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$14,062K	$14,231K	$169K	1.2%

O&M Directs YTD: $71K Favorable | Inside of Target

Labor YTD: $219K Favorable |Inside of Target

Capital

JUNE 2026

Budget	YEP	Budget Variance
$89,919,645	$106,984,416	$17,064,771

Budget	Approved Spend	Budget & Approved Spend Variance
$89,919,645	$96,915,350	$6,995,705

Initiative	Capital Approved Spend	YTD Actuals	Projections	YEP	Approved Spend Variance
IN410 - PDF_Power Delivery Facilities	$85,506,517	$19,578,067	$73,924,279	$93,502,346	$7,995,829
IN788 - Fleet ELEC	$2,528,651	$2,554,856	$1,639,899	$4,194,755	$1,666,104
IN608 - Oil Processing Trailer			$786,336	$786,336	$786,336
IN471 - FMPI – PDF_SC2	$841,000	$10,468	$410,028	$420,496	($420,504)
IN485 - Control Center Improvements	$2,059,500	$5,632	$1,364,500	$1,370,132	($689,368)
Total	**$96,915,350**	**$23,843,347**	**$83,141,069**	**$106,984,416**	**$10,069,066**

The table displays only the largest variances; smaller variances are included in the total but not shown.

IN410: The variance is driven by an accelerated schedule of approximately four weeks, resulting in a shift in dollars from 2027 to 2026. The variance does not increase the total project estimate.
IN788: An addition of vehicles to support staffing growth within traveling business units as well as vehicles originally planned to arrive in 2025 but arrived and were paid for in 2026.
IN608: The projection is the estimated amount needed to purchase an Oil Processing Trailer.
IN485: A schedule delay due to the RFP process and evaluation has caused a shift in spending from 2026 to 2027. The current year variance does not impact the total project estimate.

Management Focus

- $150K grant — to install chargers for Fleet Electrification Plan
- Phase 1: 6 Level 2 chargers at 3 sites, ~12 fleet EVs supported
- Annex + HOB live in 2026 | HQ Q1 2027 after service upgrade
- Level 2 supports overnight charging - a fraction of DC fast-charge cost

Near-Term Business Plan

2026		2027	
Q3	Q4	Q1	Q2

- PDF Project SC1- construction
- Implementation of Invoice Management Optimization Plan
- Supply Chain Improvements

- ERP
- PDF Project SC1-construction
- Facilities Master Plan Implementation
- PDF Project SC2- RFP & selection

- Install EV Chargers
- Facilities Master Plan Implementation

- PDF Project SC2
- PDF Project SC1- Logistics Planning

Long-Term Business Plan

2027 | 2028 | 2029 | 2030

- PDF Project SC1- Construction completion
- PDF Project SC2- Validation & design

- PDF Project SC1- Move in
- Facilities Master Plan Implementation

- PDF Project SC2- Construction (through completion)

- Fleet Electrification Plan

Closing Summary

- September 8 - SC1 Top-out Celebration
- October 20 - Facilities Master Plan Refresh Discussion Follow-up

Thank You!

Grant PUD

Powering our way of life.

QBR Summary

Department Name:	Key Presenters:	Date:
Shared Services	Fallon Long, Vice President	August 18, 2026

RECAP	
Issues and Drivers	Shared Services is within year-to-date financial targets, with favorable O&M Directs and Labor. Capital variances are primarily timing-related and do not indicate material changes to total project estimates. Management focus remains on improving Job Site Review completion and Interdepartmental Collaboration scores.

NEAR-TERM PLANS (CURRENT THROUGH Q2 2027)	
Project Updates	• Advance PDF Project SC1 construction and logistics planning. • Implement invoice management, supply chain, and ERP improvements. • Continue Facilities Master Plan implementation and begin PDF Project SC2 RFP/selection. • Install grant-funded fleet EV chargers at Annex and HOB in 2026; complete HQ in Q1 2027.

LONGER-TERM STRATEGY (2027 THROUGH 2029)	
Roadmap	• Complete PDF Project SC1 and transition to move-in. • Validate, design, construct, and complete PDF Project SC2. • Continue Facilities Master Plan implementation. • Prepare for 2030 fleet electrification requirements, including future charging expansion.
Strategy	Long-term strategy is focused on scalable support infrastructure, fleet readiness, stronger service delivery, and prudent use of external funding to reduce capital pressure where available.

COMMISSION SUPPORT: KEY ASKS	
Specific Requests	Commission alignment is requested on Facilities Master Plan priorities, PDF project sequencing, fleet electrification readiness, and next steps for the Facilities Master Plan refresh discussion.

Enterprise Technology

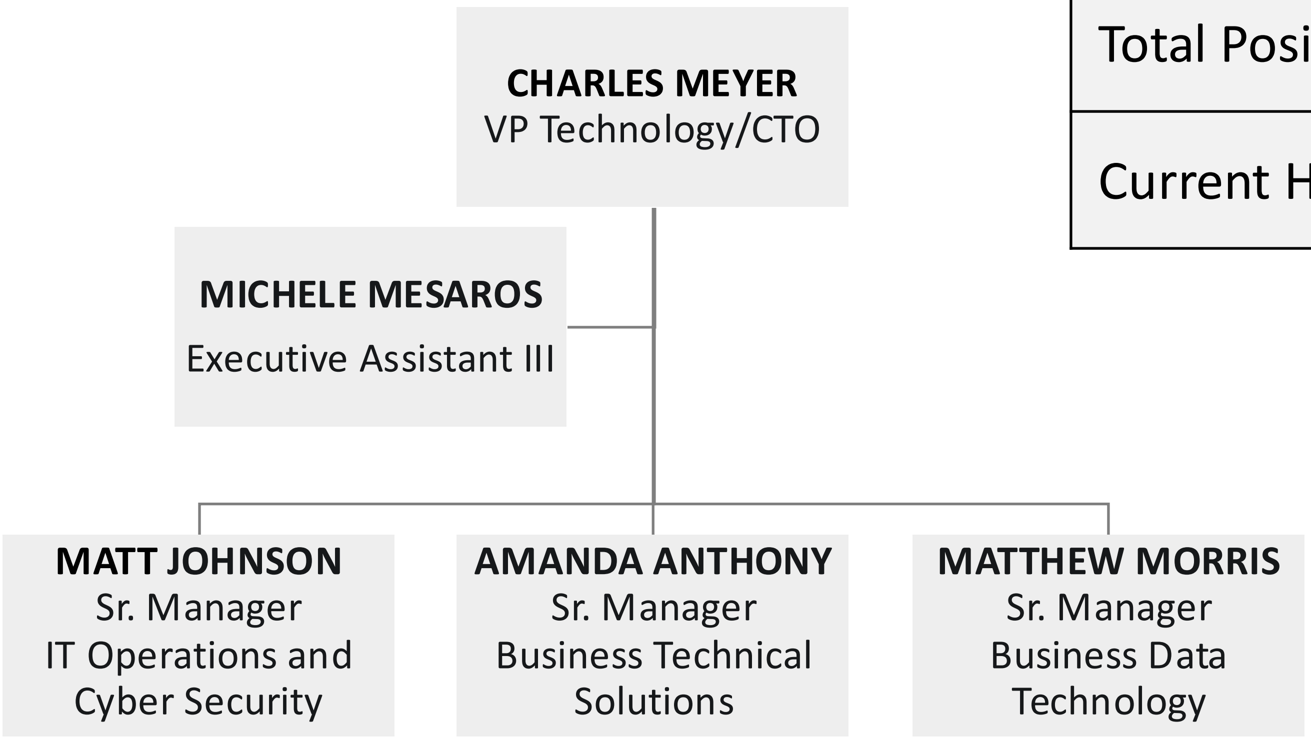
August 18, 2026

Charles Meyer, Vice President

Grant PUD

Powering our way of life.

Team



Total Positions in Org	57
Current Headcount	46

Staff Updates:

- **IT Operations and Cyber:** Josh VanHeusden promoted to Platform Operations Supervisor and Omar Reyes promoted to Cyber Sec Supervisor.
- **Business Technical Solutions:** Elijah Dotson transferred and promoted from Service Desk Technician to Software Test Engineer I and Amanda Hall promoted to Software Quality Supervisor.
- **Data Technology** Contractors: Moli Thomas.

Enterprise Balanced Scorecard

% completion of Cyber Security Control Plan	% completion of Database Warehouse Plan
Measure is currently 86%, ahead of target by 11%. Major items continue to move forward as planned including DLP enforcement policies which went live in July to strategic groups and will go Org wide soon.	*Measure is at target due to updates to plan to align with hiring plan changes and a few advancements on access to data.*
Green	Green

- Data Warehouse Plan (aka Enterprise Information System) was redone to reflect change in hiring scope for 2026.
  - This included reducing our hiring plan for 2026 and using contracted resources to fill the gaps.
  - We also saw some break throughs in access to some of our core systems.
  - With access to more core data, our MDM (Master Data Management) team is now back on schedule.
- Cyber Security Control Plan is making excellent progress. Maintaining focus on working the plan while also addressing emerging threats and security concerns.

Executive Financial Overview

JUNE 2026

O&M DIRECTS YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$5,585K	$5,334K	($251K)	-4.5%

O&M DIRECTS YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$12,396K	$12,902K	$506K	4.1%

LABOR YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$3,082K	$2,722K	($359K)	-11.7%

LABOR YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$6,751K	$6,223K	($527K)	-7.8%

COST CATEGORY TYPE	YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
IT	$3,589,885	$3,264,444	($325,441)	-9.1%
Purchased Services	$1,659,811	$1,792,354	$132,543	8.0%
Total	**$5,249,696**	**$5,056,798**	**($192,898)**	**-3.7%**

This table reflects the largest variance cost category types only.

IT: $325K Favorable | Outside of Target: Delayed payments: $41K ARCOS (PO pending), $188K Maximo TRM (PO conversion and approval transition delay), $23K Tapcon (payment pending approval)

Purchased Services: $133K Unfavorable | Outside of Target: Higher-than-expected IT services and contracted labor costs, including contractor support required due to hiring delays. Labor savings from vacant positions are expected to offset these costs by year-end.

Labor: $359K Favorable | Outside of Target: 10 vacancies as of June.

Capital

JUNE 2026

Budget	YEP	Budget Variance
$6,498,818	$7,405,783	$906,965

Budget	Approved Spend	Budget & Approved Spend Variance
$6,498,818	$7,282,244	$783,426

Initiative	Capital Approved Spend	YTD Actuals	Projections	YEP	Approved Spend Variance
IN677 - GMS Ovation Upgrade	$951,275		$1,046,790	$1,046,790	$95,515
IN268 - Server Replacements	$600,000		$670,000	$670,000	$70,000
IN595 - Mass Notification System			$63,075	$63,075	$63,075
IN547 - PPM Tool	$50,650	$88,192	$12,000	$100,192	$49,542
IN539 - Operations Optimizer		$47,265		$47,265	$47,265
IN565 - Firewall Lifecycle Fitness	$62,000	$3,184	$3,419	$6,603	($55,397)
IN504 - ERP Plus Implementation	$5,226,919	$530,263	$4,462,354	$4,992,617	($234,302)
Total	**$7,282,244**	**$964,145**	**$6,441,638**	**$7,405,783**	**$123,539**

The table displays only the largest variances; smaller variances are included in the total but not shown.

IN504 – ERP Plus Implementation: $234K Favorable | Driven by project schedule adjustments that shifted a portion of planned spending into future periods. Project objectives and deliverables remain on track..
IN547 – PPM Tool: $50K Unfavorable | Driven by the acquisition of additional licenses required to support expanding project and resource management activities.
IN539 – Operations Optimizer: $47K Favorable | Driven by project prioritization decisions that adjusted the timing of expenditures while maintaining project momentum.
IN505 – SBITA Renewal Fitness: $34K Unfavorable | Driven by assessment and renewal-related activities that occurred ahead of formal funding allocation.
IN310 – Replace Energy Management System: $30K Unfavorable | Driven by project work that proceeded ahead of approved funding allocation due to a forecasting configuration issue. Funding alignment has been identified and is being addressed.

Management Focus

Modernizing Asset Accountability

Required workflow capture, visible ownership tags, and automated follow-up improve audit readiness and device accountability.

Required capture | Audit trail | PUD ownership | Automated follow-up

What changed

Asset Tag(s) and Serial Number(s) are now required before closure in onboarding, separation, and new hardware request workflows.

This records asset movement where deployment and recovery work already occurs.

Executive value

- Improves traceability for issued and recovered equipment.
- Supports audit evidence and hands-on inventory validation.
- Reduces risk from outdated, missing, or unknown devices.
- Creates a path for automated stakeholder reporting.

Control
Required fields before closure

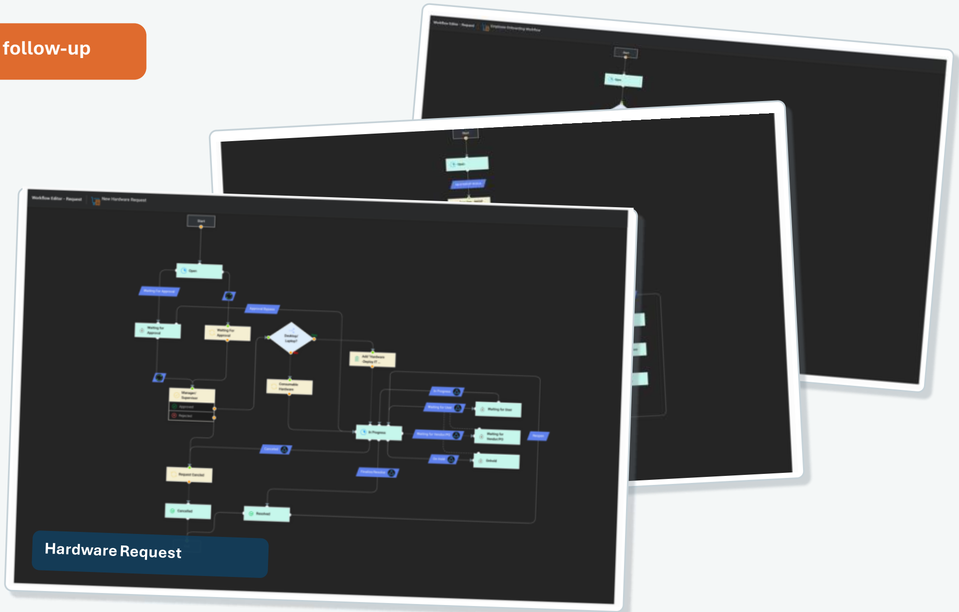
Audit
Better evidence and traceability

Security
Least privilege cleanup support

Reporting
Foundation for automation

Controls embedded in operational workflows

Actual workflow artifacts show where asset data capture now occurs.



Visible ownership + structured asset IDs

Color-coded labels identify device type. QR codes and suffixes support faster audit and reporting.

Near-Term Business Plan

2026 — 2027

Q3 | Q4 | Q1 | Q2

- Customer Information System (CIS) (Harris) contract completion
- Invoice Management Optimization (IMOP) technology work (continues)
- Expanded AI rollout (building AI Center of Excellence)
- Data pipeline development
- Customer Portal replacement project (continues)
- ERP+/D365 Solution Verification (complete)

- ERP implementation (kick-off)
- Transmission Outage Management System (OMS) kickoff
- Pilot access to data in Enterprise Information System (EIS)
- Invoice Management Optimization (IMOP) technology work (complete)

- Drawing Records replacement project (kick-off)
- Customer Information System (CIS) (Harris) project discovery work.
- Transmission and Generation Outage Management System RFP (WRAP Compliance)
- Invoice Management Optimization (IMOP) technology work (continues)

- Transmission Outage Management System implementation
- Buildout New Disaster Recovery Infrastructure in Moses Lake

- ERP+
- Enterprise Information System development
- Cyber Security enhancements

Long-Term Business Plan

2027 | 2028 | 2029 | 2030

- Advanced Distribution Management System (ADMS)
- Agentic AI infrastructure development
- DERMS

- Geospatial Information System (GIS) upgrade

- Customer Information System (CIS) (Harris)

- Enterprise Information System development

- Cyber Security enhancements

- ERP – Finance Implementation

- ERP – Supply Chain Implementation

- ERP - HR Implementation

- ERP – Asset Management Implementation

Closing Summary

- A secure, data-ready foundation is in place — the focus now shifts to enterprise modernization, anchored by the multi-year ERP transformation.
- No action required today.

Thank You!

Grant PUD

Powering our way of life.

QBR Summary

Department Name:	Key Presenters:	Date:
Enterprise Technology	Charles Meyer	August 18, 2026

RECAP	
Issues and Drivers	Staffing – several new positions were filled with internal candidates which created a need for backfills; Data Technology positions are new and taking longer to get to Recruitment. Financial overview – See above, higher-than-expected IT services and contracted labor, including contractor support required by hiring delays and project volume; labor savings from vacancies are expected to offset by year-end. Enterprise Balanced Scorecard - Both measures are Green • Cyber Security Control Plan — 86%, ahead of target by 11%. Major items are moving as planned, including DLP enforcement policies that went live in July for strategic groups and planned expansion organization wide. • Data Warehouse Plan (Enterprise Information System) — at target. The plan was rebaselined to reflect a reduced 2026 hiring scope backfilled with contracted resources; breakthroughs in core-system access have returned the Master Data Management team to schedule. Management Focus - Asset accountability has moved from manual cleanup to controlled workflow capture. Asset tag and serial number fields are now required on New Hire Onboarding, Employee Separation, and New Hardware Request templates before closure, with Grant PUD ownership labels, color coding by asset class, and QR codes supporting audit lookup. Automated check-in reminders and supervisor escalation add follow-through. The result is stronger evidence for issued and recovered equipment, reduced unknown devices, and a repeatable path to automated reporting.

NEAR-TERM PLANS (CURRENT THROUGH Q2 2027)	
Project Updates	**ERP implementation kickoff,** CIS (Harris/Northstar) contract completion, G&T Outage Management System RFP posted, expanded AI rollout and AI Center of Excellence, data pipeline work, and new disaster recovery infrastructure in Moses Lake.

LONGER-TERM STRATEGY (2027 THROUGH 2029)	
Roadmap	2027 and Beyond - CIS (Harris), Enterprise Information System development, cyber security enhancements, and ERP+ continuing as multi-year threads. Drawing Records Replacement 2028 - Geospatial Information System upgrade 2029 - Advanced Distribution Management System kickoff, DERMS discovery
Strategy	We plan to continue to develop our data technology as well as support the implementation of the ERP+ D365 & Harris/Northstar. We are also aligning the information ecosystem to be ready for the heavy use of AI and other automation efforts.

COMMISSION SUPPORT: KEY ASKS	
Specific Requests	Commission action: **ROI Change Order 3 in September**, to secure Technology staff augmentation funding through 2030. Contracted services to augment ERP+ & Other ET Portfolio projects and operational work.