Your Energy Partner®
OPPD
Omaha Public Power District

Spurgeon/Bishop

RESOLUTION NO. 6683

WHEREAS, the Board of Directors has reviewed the proposed Omaha Public Power District's 2025 Corporate Operating Plan, which includes projected revenues and expenses for the District's operations, all phases of the District's capital expenditure plan, and the District's fuel needs and expenditures; and

WHEREAS, the 2025 Corporate Operating Plan expenditures total $2,323.6 million; and

WHEREAS, the proposed 2025 Corporate Operating Plan reflects the need for the District to increase its rates by an average of 6.3% to recover its total cost requirements; and

WHEREAS, the District's Fuel and Purchased Power Adjustment – Rider 461 (FPPA) is updated annually to reflect projected Net Energy Costs (fuel, purchased power, off systems sales revenue) for the upcoming calendar year as well as Net Energy Costs that were under-recovered (or over-recovered) from prior years; and

WHEREAS, the 2025 Corporate Operating Plan contemplates an increase to the FPPA factor to 0.457 cents per kWh from 0.413 cents per kWh, which results in a 0.4% average rate impact; and

WHEREAS, District Management proposes to utilize an estimated $13.3 million (to be updated with actual results from December 2024) from the Rate Stabilization Reserve in 2024 to meet its objective of 2.0 debt service coverage, resulting in a 1% average rate increase in 2025 to replenish the Reserve; and

WHEREAS, District Management, in consultation with the District's Rate Consultant, prepared a Cost of Service Study for each customer class and applied this analysis to establish the proposed 4.9% average general rate increase, which is shown in Exhibit A hereto, and

WHEREAS, District Management proposes miscellaneous revisions to the District's Service Regulations and Rate Schedules as shown on Exhibit B hereto, and

WHEREAS, District Management proposes a change to the energy, capacity and other charges for the contract rate with the Western Area Power Administration for service to Offutt Air Force Base, and

WHEREAS, the District's rate consultant, The Brattle Group, has reviewed the 2025 Corporate Operating Plan and 2025 Rate Action Proposal as requested by the Board of Directors, has opined that the rate actions meet the requirements of Nebraska law, and recommends it for approval by the Board of Directors.

NOW, THEREFORE, BE IT RESOLVED, by the Board of Directors of the Omaha Public Power District as follows:

Your Energy Partner®

Omaha Public Power District

1. The 2025 Corporate Operating Plan for the Omaha Public Power District is hereby approved, and the Board ratifies the plan, described in this resolution, to utilize funds from the District's Rate Stabilization Reserve account, and to replenish those funds during 2025.

2. The rate changes described in Exhibit A and as set forth in the OPPD Rate Schedules attached in Exhibit B are hereby approved, effective January 1, 2025.

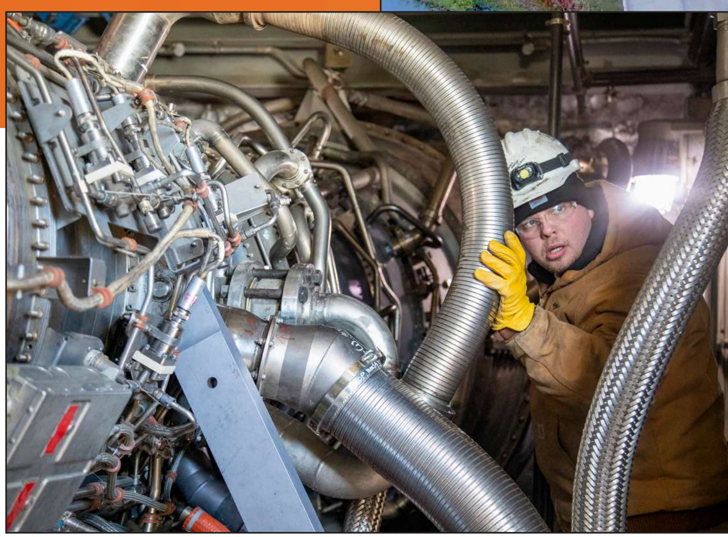
3. As described in Exhibit B, the following District Rate Schedules and Riders are repealed, effective January 1, 2025: Rider Schedule 480 (Residential Surge Guard), Rider Schedule 481 (Commercial Surge Guard), Rider Schedule 490 (Economic Development) and Rider Schedule 499 (Green Sponsorship – GSP).

4. As described in Exhibit B, the following Curtailable Rider Schedules are closed to new customers, and the automatic renewal feature is repealed and will be administered as a program, effective January 1, 2025: Rider Schedule 467, Rider Schedule 467H, Rider Schedule 467E, Rider Schedule 467V and Rider Schedule 467L.

5. As described in Exhibit B, the revisions to the following Rate Schedules and Riders are hereby approved: Rate Schedule 236 (Dusk-to-Dawn Lighting) and Rate Schedule Rider 470I (Tenant Attachment Fee), and

6. To harmonize provisions as revised and repealed, the revisions to District Service Regulations set forth on Exhibit B, are hereby approved.

2025 CORPORATE OPERATING PLAN



OPPD
Omaha Public Power District

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MANAGEMENT LETTER

Management Letter

Every day in 2024, Omaha Public Power District (OPPD) worked tirelessly to overcome challenges and prepare for a bright future.

We diversified our portfolio with energy sources that will enhance our reliability during extreme weather, reduce our carbon output and help us meet fast-growing customer demand for electricity.

We're forging ahead with plans for advanced metering infrastructure (AMI) technology, which will help us assess and restore outages with greater speed and precision.

We also powered through major challenges this year, including extreme cold and low river levels in January that affected generation plants on the Missouri River, an April tornado that devastated Elkhorn and Bennington, major flooding near our Fort Calhoun Station site and a July 31 storm with hurricane-force winds that caused the biggest outage in OPPD history.

Above all, our public power mission kept us focused on reliability, affordability and environmental sustainability. Our locally elected Board of Directors continued to guide us with forward-looking directives to serve the community.

Our 2025 Corporate Operating Plan recommends a 6.3% rate increase, composed of a 4.9% average general rate increase and a 1.4% increase from the Fuel and Purchased Power Adjustment (FPPA) factor and replenishment of the Rate Stabilization Account (RSA). The general rate increase is driven by rising net power costs from increasing load and a growing capital portfolio, leading to additional debt issuances. The FPPA and RSA impact is driven by outages and storm restoration costs. FPPA is the mechanism OPPD uses to collect price fluctuations from year to year.

For context, OPPD's rates are still far lower, on average, than other utilities. Residential rates are 25.2% below the national average, according to the U.S. Energy Information Administration's final 2023 report, the most recent data available.

As the energy landscape changes, OPPD is working on multiple fronts to adapt and thrive – and our future is bright.

L. Javier Fernandez
President and Chief Executive Officer

STRATEGIC PLANNING AND ENTERPRISE RISK

Strategic Direction

To provide clear and transparent direction on behalf of OPPD's customer owners OPPD's publicly elected Board of Directors established fifteen strategic direction (SD) policies in 2015 to which OPPD is accountable. The policies guide OPPD's planning efforts to address current and future trends, mitigate risks, pursue strategic opportunities, and prioritize resources to efficiently and effectively provide energy services to our customer owners. The SD policies leverage industry benchmarks to drive performance as a top utility and provide the basis for a scorecard to which the organization manages its performance. The Board monitors OPPD's compliance with these policies and updates the policies, when determined appropriate, to clarify strategic direction.

Our Strategic Foundation (SD-1)

Mission: To provide affordable, reliable and environmentally sensitive energy services to our customers.

Vision: "Leading the Way We Power the Future"

In implementing this vision, OPPD shall adhere to these principles:

- Strengthen the public power advantage of affordable and reliable electricity;
- Exemplify fiscal, social and environmental responsibility to optimize value to our customer-owners;
- Proactively engage and communicate with our stakeholders;
- Act transparently and with accountability for the best interest of our customer-owners;
- Collaborate, when appropriate, with partners; and
- Leverage OPPD's leadership to achieve these goals

Core Values

- We have a PASSION to serve
- We HONOR our community
- We CARE about each other

Board Strategic Direction Policies & Strategic Goals

Policy	Measure	Definition	Strategic Goal
Rates (SD-2)	% Below Regional Retail Average	Retail rate target of North Central Regional average published rates on a system average basis.	10%
Access to Credit Markets (SD-3)	Debt Coverage Ratio	Revenues less expenses divided by total annual senior and subordinate lien debt interest and principal payments.	2.0
Reliability (SD-4)	SAIDI	System Average Interruption Duration Index	< 90 mins
	SAIFI	System Average interruption Frequency Index	< 0.9 incidents
	EFOR	Equivalent Forced Outage Rate	< or = 8.0%
Customer Satisfaction (SD-5)	Absolute Satisfaction Score	Customer satisfaction for similar-sized utilities in the region across residential and business customers.	Top quartile
Safety (SD-6)	DART	Days Away, Restricted or Transferred	< or = 0.50
	PVIR	Preventable Vehicle Incident Rate	< or = 4.00
Environmental Stewardship (SD-7)	% Net reduction in CO2e	Strive to achieve net zero carbon equivalent (CO2e) emissions by 2050 relative to OPPD's 2013 benchmark with the following interim targets, 2027-41-51% net reduction. Future interim targets to be informed by and determined following the completion of the 2026 integrated resource plan.	Achieve net zero CO2e by 2050
Employee Relations (SD-8)	Employee Engagement	Composite score of employee engagement	Top quartile

For a full listing of the 15 Strategic Directives, which includes Integrated System Planning (SD-9), Ethics (SD-10), Economic Development (SD-11), Information Management & Security (SD-12), Stakeholder Outreach & Engagement (SD-13), Retirement Plan Funding (SD-14), Enterprise Risk Management (SD-15), please access the following link to the OPPD Board Policy document https://www.oppd.com/media/317205/oppd-board-policy-binder.pdf

Powering the Future to 2050

At OPPD, we've imagined the future. Powering the Future to 2050 (PF2050) is a strategic vision to make OPPD cleaner, more sustainable, and more innovative than you can believe. While others have been wondering about what's next, we've been hard at work, nights and weekends, planning out what the future of power looks like and how to bring it to life. The vision is clear – **Perfect Power**, **Customer Freedom**, and a **Cleaner World** enabled through a **Digitally Driven**, **Purpose-Driven Culture**, and **Future-Ready Posture** mindset.

In November of 2019, the Board of Directors revised SD-7 (Environmental Stewardship) and established the goal to conduct all operations in a manner that strives for the goal of net-zero-carbon production by 2050. In consideration of this revision, other SD policies, and transformational changes within and outside the industry, the Executive Leadership Team (ELT) created PF2050, which provides a strategic vision for the organization through the year 2050. PF2050 outlines a transformational journey and was developed with the expressed intent to meet or exceed the fifteen SD policies. This vision will transform OPPD to a digital utility with two-way and multi-directional power and communication flows, build a proactive grid, give customer-owners multiple options, minimize environmental impact, and reduce carbon emissions. The future is coming, and we want to make sure it is illuminated.

Acknowledging the rapidly evolving and increasingly complex environment we operate in, OPPD adopted a future-ready posture mindset. This means we are taking a thoughtful approach to investing in both core work ('keeping the lights on today') and in the efforts to power our next generation. This deliberate and agile approach resulted in the establishment of the enterprise-level resourcing priorities. These enterprise priorities are aligned under PF2050 and influence the current year's budget. The process ensures OPPD's finite resources are being used to facilitate the right work to get us closer to our objectives of Perfect Power, Customer Freedom, and a Cleaner World by 2050.

The 2025-2030 enterprise priorities (listed in priority order below) were established to provide this life essential energy service to our customer-owners and employees. Their requirements and aspirational futures are woven into the very DNA of these priorities and are the underpinnings of everything we do.

1. Resource Adequacy
2. Technology Transformation
3. Next Generation Grid
4. Master Facilities Plan

Powering the Future to 2050

OPPD leveraged PF2050 and the enterprise priorities to guide planning, prioritization, and resourcing decisions for this Corporate Operating Plan. The vision to meet the growing demands of the service territory is becoming a reality as we transition from strategic planning to resourcing the execution in service of our customer-owner requirements in 2030 and beyond. We will continue to build upon our resource prioritization & capacity management framework and strategic STEER trends and risk scanning capabilities that will result in new and better ways to deliver affordable, reliable, and environmentally sensitive energy services to our customers. Additional information regarding PF2050 can be found on https://www.oppdcommunityconnect.com/pf2050.

Enterprise Risk Management (SD-15)

Fundamental to effective planning is an understanding of the District's enterprise level risks and the development and implementation of initiatives and mitigation plans to respond to those risks. The District's Enterprise Risk Management (ERM) program specifies risk management standards, management responsibilities, and controls to help ensure risk exposures are properly identified and managed within agreed upon risk tolerance levels. Specific risk mitigation plans and procedures are maintained and reviewed periodically to provide focused and consistent efforts to mitigate various risk exposures. An increased focus on emerging risks, such as disruptive technology, was launched in 2023. This process will continue to strengthen executive leadership's understanding of these risks to ensure an optimal future-ready posture for the organization. In support of its 2025 corporate planning efforts, OPPD leveraged risk assessments and mitigation plans to help prioritize resource allocation. The ELT will continue to expand this effort by incorporating those critical trends identified and associated with PF 2050.

Theme	OPPD's Risk Management Focus
Retail Revenues & Wholesale Revenues	Persistently pursue customer and economic development to achieve economies of scale and strengthen the affordability of our rates. Optimize wholesale revenues and purchases to further benefit our customer-owners.
Resource Adequacy and Reliability	Acquire and maintain a high availability and diverse generation portfolio to serve a significantly growing customer demand.
Environmental Sensitivity	Ensure the District is compliant with all environmental regulations, well-positioned to respond to new regulations, and able to minimize our environmental impact.
Fuel Costs	Effectively manage the District's fuel portfolio through numerous mitigation strategies to continue to ensure low cost and resilient generation.
AMI & Tech Transformation Execution	Deliver world-class execution of priority initiatives that will create a future-ready posture to deliver increased value to our customer-owners.
Cyber & Physical Security	Vigorously defend customer information and District assets from all potential cyber and physical security threats inherent with national critical infrastructure.
Infrastructure Investment	Optimally invest in transmission, distribution, substation, facility, and technology assets to ensure reliable and resilient energy services and supporting functions will meet the demands of our customer-owners.
Workplace Safety	Continue promoting safety as a top priority to ensure every employee and contractor goes home as healthy as they came into work.
Community Partnership	Honor and support the communities in which we operate and fulfill the promise of public power.

ASSUMPTIONS

Assumptions

2025 Proposed Rate Action

Effective January 1, 2025, OPPD's 2025 Corporate Operating Plan assumes an average total rate increase of 6.3% across all customer classes, composed of a 4.9% average general rate increase and a 1.4% increase from the FPPA factor and replenishment of the RSA. The general rate increase is largely driven by rising net power costs and a growing capital portfolio which leads to additional debt issuances. The FPPA and replenishment of the RSA is driven by outages and storm restoration costs.

General

2024 Projected

Revenues, operations and maintenance (O&M), capital and deferred expenditures reflect the 2024 actual values and forecast submitted through September 30, 2024.

Financing/Investing

Financing

Revenue bonds with net proceeds of $460.0 million are included in the 2025 budget. The proceeds of these bonds are expected to be used for capital expenditures.

Average Earnings Rates on Funds

The average earnings rate used for all funds (including special purpose) for 2025 is 3.6% which is a decrease of 0.5% from the prior year's rate of 4.1%.

Energy Sales/Revenues

Load Forecast

The plan assumes a 12.5% increase in retail energy sales (MWh) and a 2.1% increase in the number of customers in 2025, as compared to the 2024 budget.

Assumptions

Generation and Purchased Power

Outages have been scheduled for the following base-load units in 2025:

1. Nebraska City Station Unit Number 2
2. North Omaha Station Units 4 & 5

Additionally, there are several shorter outages scheduled for other units. The purchased power budget includes generation supplied from 1,272 megawatts of wind capability, 80 megawatts of hydropower from the Western Area Power Administration, as well as 86 megawatts of solar capability.

Department Operations and Maintenance Budget

Department and division level budgets were proposed, and these plans were reviewed with the ELT for alignment with the strategic and operational objectives before submitting them in the 2025 Corporate Operating Plan for Board final approval.

Capital Budget Expenditures

The capital portfolio prioritization and allocation process continues to improve capital planning. The process enables better alignment with the strategic directives and provides more transparency of capital spending through improved project review and approval processes. The size of the capital budget continues to grow as the District undergoes system expansion to provide reliable electric service to a growing community.

Total 2025 Budget

The total 2025 Budget is $2.3 billion.

BUDGET SUMMARY
(DOLLARS IN THOUSANDS)

Total Budget	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Capital Expenditures*	$ 727,000	$ 788,000	$ 61,000	8.4
Non-Fuel Operations & Maintenance	528,335	582,729	54,394	10.3
Fuel and Purchased Power	492,691	567,138	74,447	15.1
Total Debt Service and Other Expenses	189,242	216,317	27,075	14.3
Decommissioning Expenditures**	112,918	102,596	(10,322)	(9.1)
Payments in Lieu of Taxes	45,599	53,532	7,933	17.4
Reserves	11,939	13,269	1,330	11.1
TOTAL BUDGET	**$ 2,107,724**	**$ 2,323,581**	**$ 215,857**	**10.2**

*Capital Expenditures are shown net of Contributions in Aid of Construction

**Decommissioning Expenditures represent expenditures related to Decommissioning activity, which differs from Decommissioning Funding ($10.7 million) which is an expense and is reflected on the income statement.

Budget Component Comparison	BUDGET 2024	BUDGET 2025	CHANGE
Capital Expenditures*	34.5%	33.9%	(0.6)
Non-Fuel Operations & Maintenance	25.1%	25.1%	0.0
Fuel and Purchased Power	23.4%	24.4%	1.0
Total Debt Service and Other Expenses	9.0%	9.3%	0.3
Decommissioning Expenditures**	5.4%	4.4%	(1.0)
Payments in Lieu of Taxes	2.2%	2.3%	0.1
Reserves	0.6%	0.6%	0.0
TOTAL BUDGET	**100.0%**	**100.0%**	**-**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

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Income Statement

The District uses a 2.0 debt service coverage ratio as the basis of annual budgets, which is based on SD-3 Access to Credit Markets. It should be noted that OPPD does not set budgets or other forward-looking plans on the basis of net income. Net income for 2025 is budgeted to be $203.1 million, which is $41.7 million or 25.9% higher than the 2024 budget.

Major Factors Contributing to the Change in Budgeted Operating and Net Income:

Operating revenues are $1,671.2 million, which is $238.8 million or 16.7% higher than the 2024 budget. As the District anticipates load growth across all customer classes, retail revenues are expected to increase $208.7 million or 17.0% from the 2024 budget. The increase in operating revenue was also impacted by higher wholesale revenue of $25.6 million or 15.6%. The wholesale revenue increase is largely driven by higher congestion hedging revenue. The 2024 budget took a very conservative approach to congestion hedging revenues, leading to an increase in 2025 to more closely reflect actual performance.

Operations and maintenance expenses are $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget. Fuel and purchased power account for an increase of $74.4 million, or 15.1%, when compared to 2024 budget. Other O&M increases are driven by costs and headcount growth associated with the District's strategic priorities as well as additional investment in vegetation management.

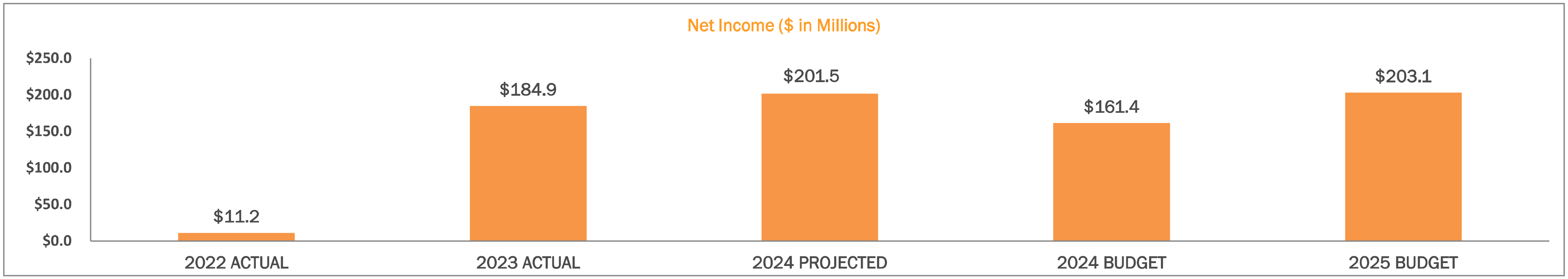
Other income is $88.8 million, which is $2.8 million or 3.2% higher than the 2024 budget amount due to largely offsetting impacts. Allowance for funds used during construction (AFUDC) is budgeted to increase by $13.1 million due to a growing capital portfolio, offset by decreased interest income of $11.9 million due to a lower earnings rate for funds on deposit.

Interest expense is $174.3 million in 2025 which is $22.6 million or 14.9% higher than the 2024 budget due to additional planned debt issuances required to execute a large capital portfolio.

OMAHA PUBLIC POWER DISTRICT
2025 CORPORATE OPERATING PLAN

INCOME STATEMENT
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
OPERATING REVENUES	$ 1,400,784	$ 1,428,905	$ 1,516,446	$ 1,432,358	$ 84,088	$ 1,671,191	$ 238,833	16.7
OPERATING EXPENSES								
O&M EXPENSE	962,458	1,036,164	1,090,192	1,021,028	69,163	1,149,867	128,839	12.6
DEPRECIATION EXPENSE	150,074	124,980	143,871	138,448	5,423	183,433	44,985	32.5
PAYMENTS IN LIEU OF TAXES	40,462	42,498	45,827	45,599	228	53,532	7,934	17.4
DECOMMISSIONING EXPENSE	141,918	33,320	16,148	15,298	850	10,694	(4,604)	(30.1)
REGULATORY AMORTIZATION	14,835	13,600	-	-	-	-	-	-
TOTAL OPERATING EXPENSE	$ 1,309,747	$ 1,250,562	$ 1,296,037	$ 1,220,373	$ 75,664	$ 1,397,526	$ 177,154	14.5
OPERATING INCOME	$ 91,037	$ 178,343	$ 220,409	$ 211,985	$ 8,423	$ 273,665	$ 61,680	29.1
INTEREST INCOME	20,481	35,412	61,646	54,211	7,434	42,355	(11,856)	(21.9)
ALLOWANCE FOR FUNDS USED	16,427	33,079	39,504	26,332	13,173	39,481	13,149	49.9
PRODUCTS AND SERVICES - NET	2,868	2,092	1,772	2,484	(712)	3,952	1,469	59.1
MISC. NON OPERATING INCOME	25,917	4,718	1,008	3,000	(1,992)	3,000	-	-
MARK TO MARKET	(60,693)	38,747	11,204	-	11,204	-	-	-
TOTAL OTHER INCOME	$ 5,000	$ 114,048	$ 115,134	$ 86,027	$ 29,108	$ 88,788	$ 2,761	3.2
TOTAL INCOME LESS OPERATING EXPENSE	$ 96,037	$ 292,391	$ 335,543	$ 298,012	$ 37,531	$ 362,453	$ 64,441	21.6
INCOME DEDUCT. & INT. CHARGES								
INTEREST EXPENSE	97,739	120,168	147,203	151,720	(4,517)	174,319	22,599	14.9
OTHER INCOME DEDUCTIONS	1,787	3,091	3,917	1,205	2,712	1,205	-	-
AMORTIZATION	(14,694)	(15,767)	(17,030)	(16,271)	(759)	(16,157)	114	(0.7)
TOTAL INCOME DEDUCT. & INT. CHARGES	$ 84,832	$ 107,491	$ 134,090	$ 136,654	$ (2,564)	$ 159,367	$ 22,713	16.6
NET INCOME	$ 11,205	$ 184,900	$ 201,453	$ 161,358	$ 40,095	$ 203,086	$ 41,728	25.9



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

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Coverage Ratios

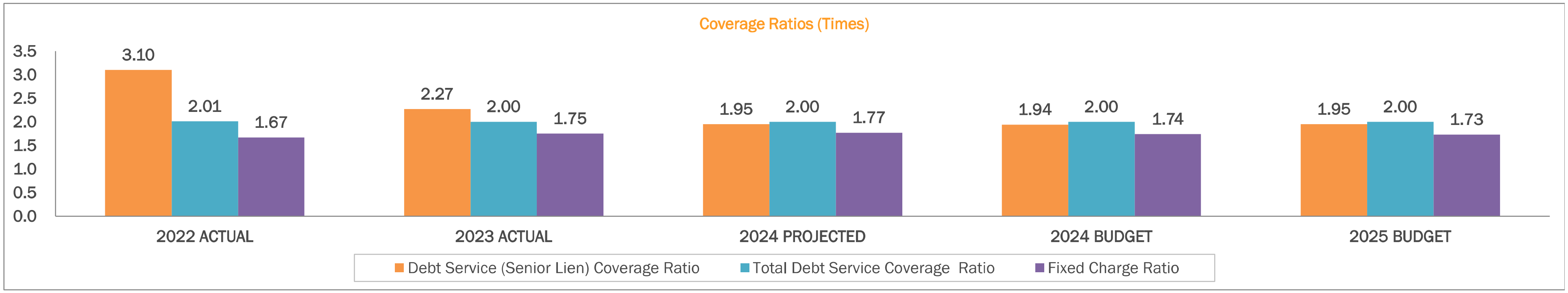
The Total Debt Service Coverage ratio, which is the key metric viewed by credit rating agencies, is budgeted to be 2.00 times in 2025, as directed by SD-3 Access to Credit Markets.

The Fixed Charge ratio is budgeted at 1.73 times in 2025, as compared to the budgeted 2024 value of 1.74 times.

The Senior Lien Debt Service Coverage ratio is budgeted to slightly increase to 1.95 compared to the 2024 metric of 1.94 times as increases in net receipts are offset by additional debt service requirements from additional borrowings. The additional debt issuances for senior lien revenue bonds are expected to be used to support a growing capital portfolio. Senior lien debt service requirements are expected to increase by $36.2 million or 19.6% from the 2024 budget amount.

COVERAGE RATIOS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
OPERATING REVENUES (EXCL. NC2)	$ 1,331,698	$ 1,354,221	$ 1,448,671	$ 1,368,804	$ 79,867	$ 1,600,681	$ 231,877	16.9
INTEREST INCOME - BONDS RESERVE ACCOUNT	1,357	3,229	5,354	3,491	1,863	4,383	892	25.6
PAYMENTS IN LIEU OF TAXES	(40,462)	(42,498)	(45,827)	(45,599)	(228)	(53,532)	(7,934)	17.4
O&M EXPENSE (EXCL. NC2 PARTICIPANT SHARE)	(930,054)	(1,000,481)	(1,055,662)	(966,215)	(89,447)	(1,118,677)	(152,462)	15.8
NET RECEIPTS	$ 362,539	$ 314,471	$ 352,536	$ 360,481	$ (7,945)	$ 432,854	$ 72,373	20.1
TOTAL DEBT SERVICE COVERAGE RATIO (DSC)	2.01	2.00	2.00	2.00	-	2.00	$0	-
DEBT SERVICE REQUIREMENTS (SENIOR LIEN)	$ 116,947	$ 138,251	$ 180,755	$ 185,183	$ (4,428)	$ 221,392	$36,209	19.6
DEBT SERVICE (SENIOR LIEN) COVERAGE RATIO	3.10	2.27	1.95	1.94		1.95		
FIXED CHARGE RATIO	1.67	1.75	1.77	1.74		1.73		



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding. Total DSC as defined in OPPD's published Strategic Directive-3: Access to Credit Markets.

Financial Statements

Debt and Financing Data

Total senior lien revenue bonds outstanding at year-end 2025 are budgeted to equal $3,480 million. The 2025 budget anticipates the issuance of approximately $460.0 million of new senior lien revenue bonds and also includes senior lien revenue bond maturities and retirements of $52.5 million.

The 2025 budget does not anticipate the issuance of new subordinated bonds as all will mature or be retired during 2024.

Total commercial paper outstanding at year-end 2025 is budgeted to remain at the 2024 level of $250.0 million. The 2025 budget does anticipate the net impact of both an issuance and retirement of $100.0 million in new commercial paper.

Total separate system (Nebraska City Unit 2 (NC2)) revenue bonds outstanding at year-end 2025 are budgeted to equal $185.1 million. The 2025 budget does not anticipate the issuance of new NC2 revenue bonds but does have NC2 revenue bond maturities and retirements of $4.4 million.

The total average interest rate on existing debt is budgeted at 4.45% at the end of 2025 and the debt to capitalization ratio is budgeted to be 65.6% for 2025.

DEBT AND FINANCING DATA
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
SENIOR LIEN REVENUE BONDS								
BALANCE - BEGINNING OF YEAR	$ 1,524,630	$ 1,935,320	$ 2,439,775	$ 2,439,775	$ -	$ 3,072,490	$ 632,715	25.9
NEW ISSUES	420,565	549,760	906,755	448,657	458,098	460,000	11,343	2.5
MATURITIES / RETIREMENTS	(9,875)	(45,305)	(274,040)	(45,895)	(228,145)	(52,535)	(6,640)	14.5
BALANCE - END OF YEAR	**$ 1,935,320**	**$ 2,439,775**	**$ 3,072,490**	**$ 2,842,537**	**$ 229,953**	**$ 3,479,955**	**$ 637,418**	**22.4**
AVERAGE INTEREST RATE (END OF YEAR)	3.85%	3.79%	4.13%	4.47%		4.44%		
SUBORDINATED								
BALANCE - BEGINNING OF YEAR	229,775	227,225	134,745	134,745	-	-	(134,745)	(100.0)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(2,550)	(92,480)	(134,745)	(2,560)	(132,185)	-	2,560	(100.0)
BALANCE - END OF YEAR	**$ 227,225**	**$ 134,745**	**$ -**	**$ 132,185**	**$ (132,185)**	**$ -**	**$ (132,185)**	**(100.0)**
AVERAGE INTEREST RATE (END OF YEAR)	4.23%	6.54%		4.01%				
COMMERCIAL PAPER								
BALANCE - BEGINNING OF YEAR	325,000	250,000	250,000	250,000	-	250,000	-	-
NEW ISSUES	-	100,000	100,000	-	100,000	100,000	100,000	-
MATURITIES / RETIREMENTS	(75,000)	(100,000)	(100,000)	-	(100,000)	(100,000)	(100,000)	-
BALANCE - END OF YEAR	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ 250,000**	**$ -**	**$ 250,000**	**$ -**	**-**
AVERAGE INTEREST RATE (END OF YEAR)	1.50%	3.72%	4.00%	4.00%		4.27%		
SEPARATE SYSTEM REVENUE BONDS (NC2)								
BALANCE - BEGINNING OF YEAR	201,495	197,680	193,680	193,680	-	189,480	(4,200)	(2.2)
NEW ISSUES	-	-	-	-	-	-	-	-
MATURITIES / RETIREMENTS	(3,815)	(4,000)	(4,200)	(4,200)	-	(4,415)	(215)	5.1
BALANCE - END OF YEAR	**$ 197,680**	**$ 193,680**	**$ 189,480**	**$ 189,480**	**$ -**	**$ 185,065**	**$ (4,415)**	**(2.3)**
AVERAGE INTEREST RATE (END OF YEAR)	4.95%	4.95%	4.95%	4.95%		4.95%		
TOTAL AVERAGE INTEREST RATE (END OF YEAR)	**3.74%**	**3.98%**	**4.32%**	**4.44%**		**4.45%**		
TOTAL INTEREST EXPENSE (ON DEBT)	**$ 84,832**	**$ 107,491**	**$ 134,090**	**$ 136,654**	**$ (2,564)**	**$ 159,367**	**$ 25,277**	**18.9**
DEBT TO CAPITALIZATION RATIO	**64.00%**	**64.00%**	**65.60%**	**66.00%**		**65.60%**		

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Financial Statements

Cash Flow Analysis

2025 Budget Compared to 2024 Budget

Cash Receipts

2025 cash receipts are budgeted to increase by $221.5 million to $1,714.3 million, a 14.8% change. This increase is primarily due to increased retail revenue from projected load growth and the general rate increase to customers.

Cash Disbursements

2025 cash disbursements are budgeted to increase by $221.5 million to $2,251.4 million, a 10.9% shift. Increases in cash disbursements relate to capital expenditures from a growing capital portfolio that also impacts increased debt service to support the capital portfolio. In addition, purchased power is expected to increase by $66.6 million due to higher purchase volumes to support customer load growth.

The budgeted values of cash receipts and disbursements result in a year-end cash balance of $688.3 million in 2025, a 30.1% or $159.4 million increase over 2024 budget.

CASH FLOW ANALYSIS
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
CASH BEGINNING OF PERIOD	$ 636,681	$ 667,880	$ 693,066	$ 642,041	$ 51,025	$ 765,405	$ 123,364	19.2
RECEIPTS								
RETAIL REVENUES	1,126,285	1,109,853	1,266,898	1,222,054	44,844	1,423,890	201,836	16.5
WHOLESALE REVENUES (INCL. NC2)	248,490	239,797	229,419	168,881	60,538	194,677	25,796	15.3
INTEREST INCOME	50,004	53,081	59,235	57,211	2,024	45,034	(12,177)	(21.3)
OTHER ELECTRIC REVENUES	42,940	46,205	46,437	42,234	4,203	46,776	4,542	10.8
PRODUCTS & SERVICES	2,086	2,978	2,696	2,484	212	3,953	1,469	59.1
USE OF RESERVE ACCOUNTS	-	-	13,269	-	13,269	-	-	-
TOTAL RECEIPTS	$ 1,469,805	$ 1,451,914	$ 1,617,954	$ 1,492,864	$ 125,090	$ 1,714,329	$ 221,465	14.8
DISBURSEMENTS								
CAPITAL EXPENDITURES	551,032	574,608	762,355	727,000	35,355	788,000	61,000	8.4
O&M EXPENSE (W/O FUEL & PURCHASED POWER)	409,119	497,369	523,309	540,396	(17,087)	581,882	41,486	7.7
PURCHASED POWER	357,276	337,969	406,935	310,416	96,519	377,052	66,636	21.5
DEBT SERVICE	146,457	272,569	209,453	215,568	(6,115)	244,632	29,064	13.5
FUEL	188,414	157,894	147,135	178,358	(31,223)	187,841	9,483	5.3
PAYMENTS IN LIEU OF TAXES	38,605	40,494	42,281	42,882	(601)	48,044	5,162	12.0
CONTRIBUTIONS TO RESERVE ACCOUNTS	-	-	-	-	-	13,269	13,269	-
DECOMMISSIONING EXPENSE	141,918	33,320	16,303	15,298	1,005	10,694	(4,604)	(30.1)
CHANGES IN OTHER NET ASSETS	(17,420)	(36,663)	40	-	40	-	-	-
TOTAL DISBURSEMENTS	$ 1,815,401	$ 1,877,560	$ 2,107,810	$ 2,029,918	$ 77,892	$ 2,251,415	$ 221,497	10.9
NET OPERATING CASH FLOW	$ (345,596)	$ (425,646)	$ (489,856)	$ (537,054)	$ 47,198	$ (537,086)	$ (32)	0.0
FINANCING	474,385	477,870	968,651	448,657	519,994	483,000	34,343	7.7
FINANCING COST / RESERVE AMOUNT	(22,590)	(27,038)	(46,126)	(24,676)	(21,450)	(23,000)	1,676	(6.8)
COMMERCIAL PAPER - NET	(75,000)	-	-	-	-	-	-	-
OTHER	-	-	(360,330)	-	(360,330)	-	-	-
TOTAL FINANCING	$ 376,795	$ 450,832	$ 562,195	$ 423,981	$ 138,214	$ 460,000	$ 36,019	8.5
TOTAL CHANGE IN CASH	31,199	25,186	72,339	(113,073)	185,412	(77,086)	35,987	(31.8)
CASH END OF PERIOD	$667,880	$693,066	$765,405	$528,968	$236,437	$688,319	$159,351	30.1
DECOMMISSIONING FUND	$534,901	$479,964	$406,731	$346,768	$59,963	$288,684	($58,084)	(16.8)

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

ENERGY SALES

Energy Sales

Electric Energy Sales & Electric Customers

Total electric energy sales are budgeted to be 18,878,664 MWh, which is 8.5% or 1,479,981 MWh more than the 2024 budget. Retail energy sales are budgeted to be 15,355,048 MWh, or 12.5%, greater when compared to 2024 budget. This increase is driven by load growth across all customer classes. Wholesale energy sales (including NC2 participation sales) are budgeted to decrease by 226,624 MWh or 6.0% from 2024 budget as volumes are expected to decrease due to load growth consuming owned generation and leaving less energy available to sell into the marketplace.

In 2025, the average number of retail customers is budgeted to increase by 8,762, a 2.1% increase from 2024 budget.

ELECTRIC ENERGY SALES AND CUSTOMERS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET. MWh CHANGE	% CHANGE
ELECTRIC ENERGY SALES (MWh)								
RESIDENTIAL	3,937,046	3,947,870	3,857,951	3,995,295	(137,344)	4,044,941	49,646	1.2
COMMERCIAL	3,763,330	3,796,608	3,800,810	3,891,422	(90,613)	3,927,174	35,752	0.9
INDUSTRIAL	4,293,784	4,683,632	5,812,465	5,703,474	108,990	7,318,775	1,615,301	28.3
UNBILLED SALES	111,815	(56,155)	83,552	58,252	25,301	64,158	5,906	10.1
RETAIL ENERGY SALES	**12,105,976**	**12,371,955**	**13,554,778**	**13,648,443**	**(93,666)**	**15,355,048**	**1,706,604**	**12.5**
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
TOTAL MWh SALES	**16,516,668**	**15,697,593**	**17,120,459**	**17,398,684**	**(278,224)**	**18,878,664**	**1,479,981**	**8.5**
ELECTRIC CUSTOMERS (12 MONTH AVG.)								
RESIDENTIAL	351,712	357,528	363,042	361,464	1,578	369,548	8,084	2.2
COMMERCIAL	49,550	49,782	50,320	49,987	333	50,665	678	1.4
INDUSTRIAL	135	133	135	149	(14)	149	-	-
TOTAL RETAIL CUSTOMERS	**401,397**	**407,443**	**413,497**	**411,600**	**1,897**	**420,362**	**8,762**	**2.1**
kWh / CUSTOMER								
RESIDENTIAL	11,194	11,042	10,627	11,053	(426)	10,946	(107)	(1.0)
COMMERCIAL	75,950	76,265	75,533	77,849	(2,316)	77,513	(336)	(0.4)
INDUSTRIAL	31,805,809	35,215,275	43,055,293	38,278,351	4,776,942	49,119,296	10,840,944	28.3
AVERAGE kWh / CUSTOMER	**29,881**	**30,503**	**32,579**	**33,018**	**(439)**	**36,376**	**3,358**	**10.2**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

Energy Sales

Operating Revenues

Total electric operating revenues for 2025 are budgeted to be $1,671.2 million, which is $238.8 million or 16.7% above the 2024 budgeted operating revenues. Retail revenues are $208.7 million or 17.0% greater than 2024 budget due to load growth across all customer classes. Wholesale revenues are $25.6 million or 15.6% higher when compared to the 2024 budget primarily due to increased congestion hedging revenue.

OPERATING REVENUES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
ELECTRIC OPERATING REVENUES								
RESIDENTIAL	$ 460,848	$ 472,633	$ 479,045	$ 490,025	$ (10,980)	$ 539,712	$ 49,687	10.1
COMMERCIAL	336,360	350,956	371,319	378,580	(7,261)	402,565	23,985	6.3
INDUSTRIAL	291,343	317,828	378,704	363,789	14,915	504,432	140,642	38.7
UNBILLED REVENUES/ADJUSTMENTS	10,556	(2,354)	4,267	5,185	(918)	5,677	492	9.5
FPPA RECEIVABLE AMORTIZATION	7,400	(7,400)	4,766	-	4,766	(4,766)	(4,766)	-
USE OF (CONTRIBUTION TO) RESERVE	(6,000)	7,000	13,269	(11,939)	25,208	(13,269)	(1,330)	11.1
TOTAL RETAIL SALES	**$ 1,100,507**	**$ 1,138,663**	**$ 1,251,370**	**$ 1,225,640**	**$ 25,730**	**$ 1,434,351**	**$ 208,711**	**17.0**
NC2 PARTICIPANTS	69,086	74,684	67,775	63,554	4,221	70,511	6,956	10.9
OTHER	187,392	168,896	150,753	100,930	49,823	119,554	18,624	18.5
TOTAL WHOLESALE REVENUES	**$ 256,478**	**$ 243,580**	**$ 218,528**	**$ 164,484**	**$ 54,044**	**$ 190,065**	**$ 25,580**	**15.6**
TOTAL SALES OF ELECTRIC ENERGY	**$ 1,356,985**	**$ 1,382,243**	**$ 1,469,899**	**$ 1,390,125**	**$ 79,774**	**$ 1,624,416**	**$ 234,291**	**16.9**
OTHER ELECTRIC REVENUES	43,799	46,662	46,547	42,233	4,314	46,776	4,542	10.8
TOTAL ELECTRIC OPERATING REVENUES	**$1,400,784**	**$1,428,905**	**$1,516,446**	**$1,432,358**	**$84,088**	**$1,671,191**	**$238,833**	**16.7**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

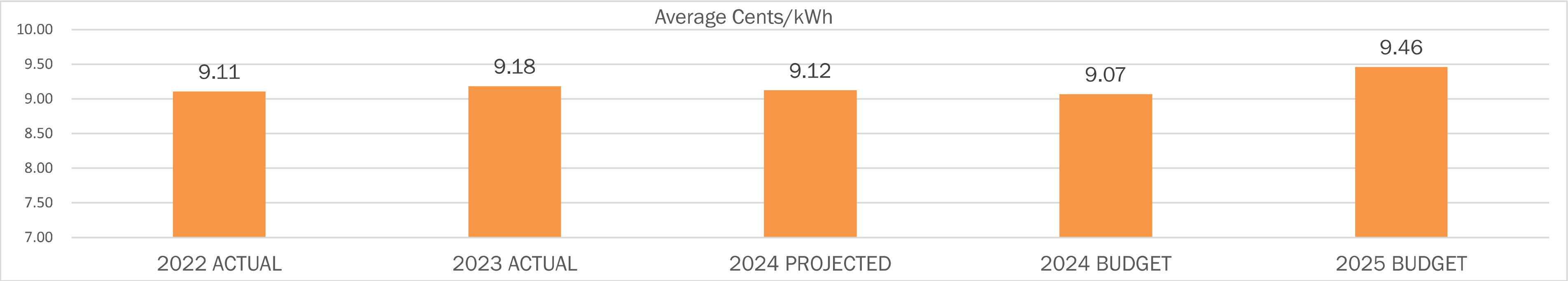
Energy Sales

Average Cents/kWh

The 2025 average price per kWh for retail customers is budgeted to be 9.46 cents. This is 0.39 cents, or a 4.3% increase, from the 2024 budget. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used as a baseline to determine the appropriate rate increase for each class. Individual customer impacts will vary based on their specific rate class and usage patterns.

AVERAGE CENTS/kWh

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	% CHANGE
RESIDENTIAL	11.73	11.97	12.42	12.27	0.15	13.34	1.07	8.7
COMMERCIAL	8.95	9.24	9.77	9.73	0.04	10.25	0.52	5.4
INDUSTRIAL	6.88	6.79	6.52	6.38	0.14	6.89	0.51	8.0
RETAIL AVERAGE *	**9.11**	**9.18**	**9.12**	**9.07**	**0.06**	**9.46**	**0.39**	**4.3**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.
* Average rates are from the revenue recognized on the Income Statement and do not incorporate accrued unbilled. These rates differ from customer billed rates and are calculated for benchmarking and illustrative purposes only.

NET SYSTEM REQUIREMENTS

Net System Requirements

Net system requirements (total retail sales as shown on the next page) for 2025 are budgeted to be 16,096,875 MWh, an increase of 1,731,308 MWh or 12.1% from the 2024 budget. The major components of net system requirements are below by sales and supply components.

Total sales are budgeted to increase 1,479,981 MWh or 8.5% from the 2024 budget, an increase largely driven by retail sales with an increase of 1,706,605 or 12.5% when compared to the 2024 budget.

For supply components, firm/participation purchases are the largest change with a budgeted increase of 1,143,962 MWh or 27.5% from the 2024 budget due to Platteview Solar and Milligan Wind being in service for the entirety of 2025.

Net System Requirements
Sales and Supply Components (MWh)

	BUDGET 2024	BUDGET 2025	INCREASE / (DECREASE)	% CHANGE
Sales Components				
Retail Sales	13,648,443	15,355,048	1,706,604	12.5
NC2 Participation Sales	2,096,963	1,894,840	(202,123)	(9.6)
Wholesale Energy Sales	1,653,278	1,628,777	(24,501)	(1.5)
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**
Supply Components				
Generation	10,147,180	10,252,594	105,414	1.0
Purchased Power Agreements	4,158,744	5,302,706	1,143,962	27.5
Wholesale Purchases	3,809,884	4,065,192	255,308	6.7
Lost or Unaccounted For	(717,124)	(741,828)	(24,703)	3.4
Total	**17,398,684**	**18,878,664**	**1,479,981**	**8.5**

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

NET SYSTEM REQUIREMENTS

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET MWh CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
GENERATION (MWh)								
GENERATION	**9,335,878**	**7,959,596**	**7,595,771**	**10,147,180**	**(2,551,408)**	**10,252,594**	**105,414**	**1.0**
FIRM/PARTICIPATION PURCHASES	4,473,672	3,514,769	4,484,291	4,158,744	325,547	5,302,706	1,143,962	27.5
WHOLESALE PURCHASES	3,198,414	4,655,118	5,544,605	3,809,884	1,734,721	4,065,192	255,308	6.7
TOTAL PURCHASES	**7,672,086**	**8,169,888**	**10,028,896**	**7,968,628**	**2,060,268**	**9,367,898**	**1,399,270**	**17.6**
TOTAL INPUT	**17,007,963**	**16,129,483**	**17,624,668**	**18,115,808**	**(491,140)**	**19,620,492**	**1,504,684**	**8.3**
WHOLESALE ENERGY SALES								
NC2 PARTICIPANT	1,867,157	1,355,808	2,168,480	2,096,963	71,517	1,894,840	(202,123)	(9.6)
OTHER	2,543,536	1,969,829	1,397,202	1,653,278	(256,076)	1,628,777	(24,501)	(1.5)
TOTAL WHOLESALE ENERGY SALES	**4,410,693**	**3,325,638**	**3,565,682**	**3,750,240**	**(184,559)**	**3,523,617**	**(226,624)**	**(6.0)**
NET SYSTEM REQUIREMENTS	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**
TOTAL RETAIL SALES	12,105,976	12,371,955	13,554,778	13,648,443	(93,666)	15,355,048	1,706,604	12.5
ENERGY LOST OR UNACCOUNTED FOR	491,295	431,890	504,208	717,124	(212,916)	741,828	24,703	3.4
TOTAL RETAIL SALES	**12,597,271**	**12,803,845**	**14,058,986**	**14,365,568**	**(306,582)**	**16,096,875**	**1,731,308**	**12.1**

PEAK LOAD (MW)								
PEAK LOAD EXCLUDING DEMAND RESPONSE	2,680	2,928	2,959	3,009	(50)	3,164	155	5.2
DEMAND RESPONSE*	126	129	140	140	(0)	128	(12)	(8.6)
PEAK LOAD INCLUDING DEMAND RESPONSE	2,554	2,799	2,819	2,869	(50)	3,036	167	5.8
LOAD FACTOR (%) - REFLECTS DEMAND RESPONSE	56.3	52.2	56.9	57.2	(0.2)	60.5	3.4	5.9

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

* Does not include voluntary demand response

OPERATIONS AND MAINTENANCE EXPENSE

Operations and Maintenance Expense

The District's 2025 total budgeted O&M expense is $1,149.9 million, which is $128.8 million or 12.6% higher than the 2024 budget.

2025 Budget Compared to 2024 Budget

Purchased power, including wind purchases, represents 33.0% of total O&M expense and is budgeted at $379.7 million. This represents an increase of $67.2 million or 21.5% above the 2024 budget amount. The increase from the 2024 budget is primarily due to higher purchase volumes to serve anticipated customer load growth. As load growth outpaces owned generation, purchased power volumes are expected to increase.

Fuel expense is budgeted at $187.4 million, an increase of $7.3 million or 4.0% more than the 2024 budgeted amount primarily due to a full year of generation from Standing Bear Lake and Turtle Creek stations.

Transmission and distribution expense is budgeted at $192.7 million, which is $26.2 million or 15.7% more than the 2024 budgeted amount. The increase over the budget amount is attributable to additional external services, including tree trimming and cable locating, as well as increased headcount supporting growth at the utility.

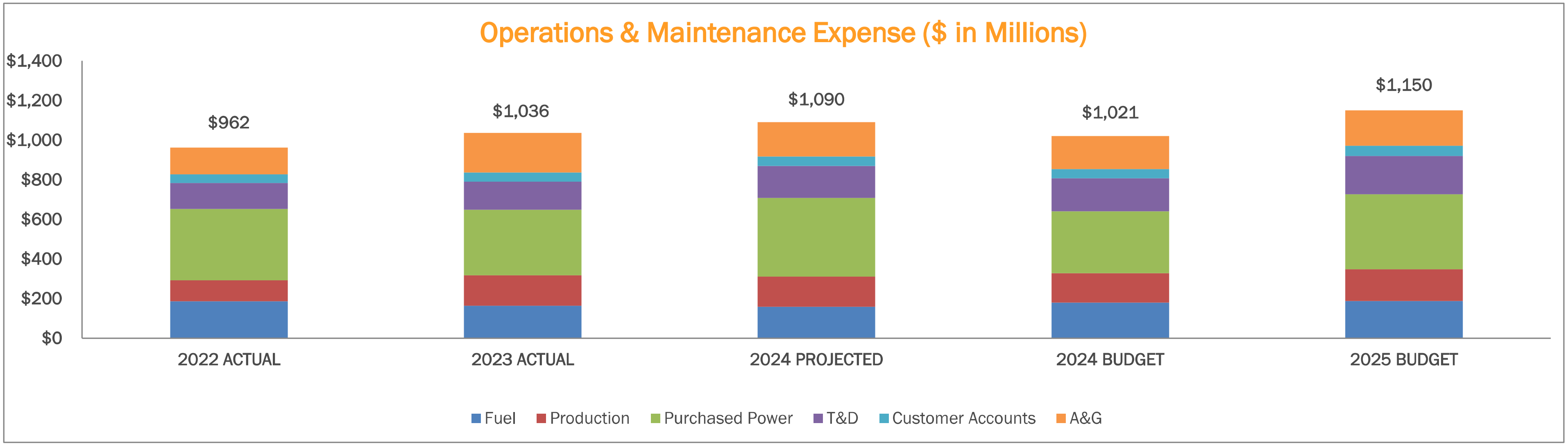
Administrative and general expense is budgeted at $178.9 million. This category reflects an increase of $12.0 million or 7.2% more than the 2024 budget. The increase in 2025 is primarily related to rising costs associated with salary and benefits driven by both higher rates and an increase in the number of covered employees.

Production expense is budgeted to be $159.7 million, which is $12.0 million or 8.1% above the 2024 budgeted amount and is also impacted by a full year of operation at two new generating facilities, Standing Bear Lake and Turtle Creek as well as headcount growth.

Decommissioning expense represents the annual funding of the decommissioning liability. Decommissioning funding for 2025 is budgeted to be $10.7 million, which is $4.6 million or 30.1% less than the 2024 budget. Contributions to decommissioning represent investment earnings on balances in the decommissioning trust.

OPERATIONS AND MAINTENANCE EXPENSE
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
PURCHASED POWER	$ 360,420	$ 332,382	$ 397,566	$ 312,527	$ 85,039	$ 379,716	$ 67,189	21.5
FUEL	186,359	164,240	157,857	180,164	(22,307)	187,422	7,258	4.0
SUBTOTAL	**546,779**	**496,622**	**555,423**	**492,691**	**62,732**	**567,138**	**74,447**	**15.1**
TRANSMISSION AND DISTRIBUTION	130,856	141,390	160,558	166,553	(5,995)	192,708	26,155	15.7
ADMINISTRATIVE AND GENERAL	135,402	199,820	173,038	166,938	6,100	178,926	11,988	7.2
PRODUCTION	105,534	152,812	152,976	147,748	5,228	159,699	11,951	8.1
CUSTOMER	43,887	45,520	48,196	47,096	1,100	51,396	4,300	9.1
TOTAL O&M EXPENSE	**$ 962,458**	**$ 1,036,164**	**$ 1,090,192**	**$ 1,021,028**	**$ 69,166**	**$ 1,149,867**	**$ 128,841**	**12.6**
DECOMMISSIONING EXPENSE	**$ 141,918**	**$ 33,320**	**$ 16,148**	**$ 15,298**	**$ 850**	**$ 10,694**	**$ (4,604)**	**(30.1)**



NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.

CAPITAL EXPENDITURE PLAN

Capital Expenditure Plan

Capital Expenditures

The 2025 capital budget was derived by breaking investments into three categories, sustain, enterprise priority and expand. This categorization ensures the District invests at appropriate levels to maintain existing assets but also invests in the continuing expansion of the utility.

Sustain - capital projects aimed at maintaining and improving existing assets

Expand - new assets, increasing the District's asset base

Enterprise Priority - projects directly related to Resource Adequacy, Technology Transformation, Next Generation Grid and the Master Facilities Plan

Capital expenditures represent 33.9% of the total 2025 budget. Capital expenditures are budgeted at $788.0 million, which is $61.0 million or 8.4% more than the 2024 budget.

The year over year growth is primarily related to investments in District expansion and enterprise priorities. Enterprise priority projects are budgeted at $474.1 million, which is a $70.6 million increase over the 2024 budget of $403.5 million, primarily related to investments in new generation. Expand, which includes projects related to load growth and economic development, are budgeted at $120.7 million, an increase of $15.4 million from the 2024 budget. Partially offsetting the budget growth in expand and enterprise priority is a decrease in sustain assets, which have a 2025 budget of $193.3 million, a decrease of $24.9 million from the 2024 budget of $218.2 million. While the District invests a larger percentage of the capital portfolio on enterprise priority and expand projects, the level of investment in sustain assets is decreasing but is still approximately $7.4 million greater than the historical investment rate.

Transmission and Distribution is budgeted at $338.6 million, a decrease of $17.6 million or 4.9% from the 2024 budget. The decrease is largely due to 2024 budgeted investments in owned solar generation that did not materialize, partially offset by additional investment in enterprise priorities, particularly Resource Adequacy and Master Facilities Plan as the District builds out transmission and distribution infrastructure to support new generation and invests in improved facilities.

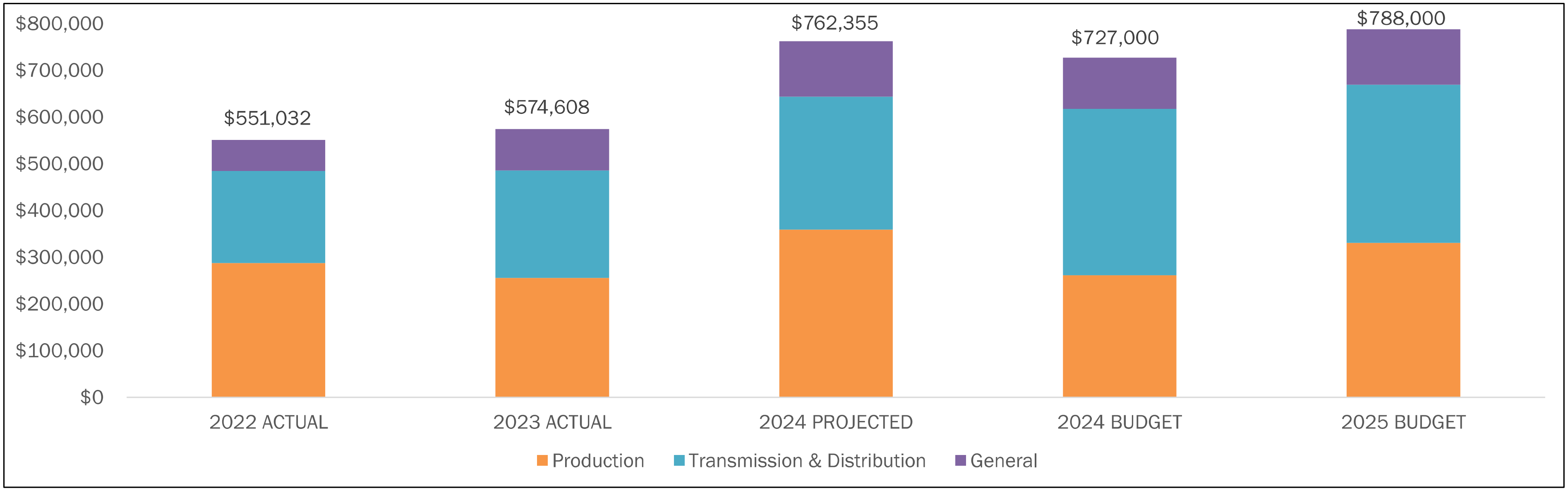
Production increased to $330.6 million from the 2024 budget spend of $261.3 million. The change of $69.3 million or 26.5% is primarily related to the net impact of decreased spending on Power with Purpose projects as those units are expected to come online in 2024, offset by investments in new combustion turbines that is ramping up in 2025.

General for 2024 is budgeted to be $118.8 million, which is $9.2 million or 8.4% higher than the 2024 budget. The increase is the result of investment in Next Generation Grid as the District prepares to implement advanced metering infrastructure technology.

CAPITAL EXPENDITURES
(DOLLARS IN THOUSANDS)

	ACTUAL 2022	ACTUAL 2023	PROJECTED 2024	BUDGET 2024	VARIANCE 2024	BUDGET 2025	25 BUDGET VS. 24 BUDGET $ CHANGE	25 BUDGET VS. 24 BUDGET % CHANGE
TRANSMISSION AND DISTRIBUTION	$ 197,344	$ 230,381	$ 284,302	$ 356,176	$ (71,874)	$ 338,625	$ (17,551)	(4.9)
PRODUCTION	287,260	255,580	359,190	261,259	97,931	330,586	69,327	26.5
GENERAL	66,428	88,647	118,862	109,565	9,297	118,789	9,224	8.4
TOTAL	$ 551,032	$ 574,608	$ 762,355	$ 727,000	$ 35,355	$ 788,000	$ 61,000	8.4

NOTE: Some columns may not foot exactly due to the method used for individual line item rounding.



CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Near Term Generation Support generation and transmission & distribution for Board Resolution No. 6582 approved on August 15, 2023	$ 149,360	$ 269,671
Master Facilities Plan Investment and upgrades to various OPPD facilities, which are all over 30 years old with only minor enhancements throughout their life	45,785	107,150
Circuit and Substation Upgrades Upgrade and replace multiple circuits and substations due to the expansion of our transmission and distribution infrastructure	61,951	82,076
AMI - Smart Grid Technology to support AMI	34,830	66,265
Transformer Purchases and Replacements Procure transformers to replace aging equipment and support load growth	31,522	30,777
Power with Purpose Support generation and transmission & distribution for Board Resolution No. 6351 approved on November 14, 2019	147,228	21,816

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Customer Service Residential Project Purchase and installation of underground or overhead infrastructure to new residential developments	$ 18,934	$ 18,432
Transportation Fleet Replacement Routine replacement of OPPD-owned transportation equipment, including light, medium and heavy duty trucks and construction equipment	16,383	18,007
Transmission Distribution Improvement Program-Cable Replacement Replace the worst performing underground distribution cable on a performance driven basis	16,548	15,645
North Omaha Extension Supports continued operation of North Omaha Station	10,690	13,292
Customer Service Commercial and Industrial Project Purchase and installation of underground or overhead infrastructure for commercial and industrial customers	13,182	13,157
Ground Line Inspection and Treatment Pole Replacement Replace degraded wood poles and structures used for transmission and distribution	7,945	11,019

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Subscription Software Renewals Renew subscription based software used by the district to conduct business	$ 4,767	$ 10,631
Transmission Distribution Improvement Program-Conductors Replace junk conductors on a performance driven basis	6,893	10,088
Transmission and Distribution Street & Highway Project Relocation of OPPD transmission and distribution facilities that are located in public road right-of-way	10,501	10,000
Coal Handling Upgrade Update Nebraska City coal handling system to reduce single point failure possibility	1,258	7,149
Expansion of Computing Storage Allows for real time expansion of computing capacity to allow for growth and support OPPD strategic initiatives	-	5,859
Energy Marketing Trade System OPPD will migrate the Energy Marketing and Trading processes to an industry standard	-	5,075
Substations and Control Centers Security Upgrades Security modifications required to address identified threats and vulnerabilities at various substation and control centers	12,887	4,946

CAPITAL EXPENDITURES (DIRECT)
SIGNIFICANT PROJECT DESCRIPTIONS AND HIGHLIGHTS
(Dollars in Thousands)

RECOMMENDED PROJECTS:	2024 Projection	2025 Budget
Arbor Railroad Line Improvements Repair and replace bridges, ties, ballast, rail, and crossings along the OPPD owned Arbor Rail line	$ 18,021	$ 4,832
Transmission and Distribution Street Light Project Relocation of OPPD street lights facilities that are located in public road right-of-way	3,500	3,500
Nebraska City Common Intake Vacuum Lift System Supports continued operation of Nebraska City at low river levels	-	3,150
Cass County Combustion Inspection Perform manufacturer recommended inpsection and repairs	-	2,950
Bellevue Transmission Redesign Improve the reliability and resiliency of the Bellevue transmission system	876	2,860
Large Motor Capital Repairs Support planned and emergent motor rewinds and replacements	-	2,800
Generation Station Intake Structure Environmental Upgrade Replace existing traveling screens (circulating water intake structure) at North Omaha and Nebraska City Fossil locations for renewal of the environmental permit	2,462	2,405

November 25, 2024

THE Brattle GROUP

Board of Directors
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

Ladies and Gentlemen:

As requested by the Board of Directors and Management of the Omaha Public Power District (the District), The Brattle Group has reviewed the 2025 Corporate Operating Plan (COP) prepared by the District and is providing this letter report to comply with this request. This review aims to provide an independent, high-level assessment of the District's operating and financial projections for 2025.

In performing our review, we evaluated the 2025 COP for consistency with prudent utility practices and the reasonableness of the budget estimates established. In addition, we reviewed the 2025 Corporate Operating Plan and associated presentations, which provided further details on many of the Operating Plan's major components. The primary presentation topics included energy production and delivery, load forecasting, nuclear decommissioning, fuel planning, technology and security, safety and facilities, employee benefits, and system transformation, which we will first discuss individually, followed by a summary of the entire Operating Plan:

Production Cost Modeling. OPPD team undertakes production cost modeling to forecast future generation capacity and dispatch through 2034. Updated with generation unit parameters fuel and commodity forecasts, the model incorporates the 2023 Near Term Generation study's resource expansion plan to meet the District's forecasted demand and energy requirements. It also incorporates SPP's regional transmission plans and develops dispatch on an hourly resolution with all SPP and MISO units. The model uses higher SPP energy and peak demand forecasts based on the near-term adjusted 2023 SPP FERC 714 submission. SPP's ITP Future 1 and ITP Future 2 were compared against other recent SPP portfolio projections and the accredited capacity required for regional resource adequacy based on future seasonal planning reserve margins in determining the model's SPP regional resource portfolio. Based on this information, the recommended portfolio implies a conservative retirement of conventional resources and the addition of renewable resources compared to the ITP scenarios.

In OPPD's modeling, Net Service Requirements ramped up significantly compared to 2023 levels due to data center and other new large loads. OPPD team provided forecasts of gas and coal commodities and delivered fuel forecasts through 2029. It also provided power price forecasts over the same period, which is in the range of $16/MWh to $45/MWh, and represent gradual increases in the next five years, tracking increases in gas prices. The District continues its commitment to retiring its coal-fired North Omaha Station. It plans to preserve system reliability by pursuing natural gas conversions at North Omaha and bringing new thermal assets (Turtle Creek and Standing Bear Lake) online. Based on the plan, the District will also add around 1600 MW of carbon-free capacity by 2030, 300 MW of battery storage capacity, and 900 MW of new natural gas capacity by 2029. Overall, near-term generation capacity is planned to grow by roughly 3 GW by 2030 relative to 2024.

The OPPD team's assumptions in developing the production cost modeling reflect a thoughtful and reasonable approach considering the transitioning electricity utility industry. Similar to many other regions across the US, the District is seeing a sharp increase in load forecasts due to demand from data centers and other large loads. We observed that the OPPD team has carefully incorporated these new trends in loads as well as fuel prices in their modeling efforts. Over the next five years, the District forecasts that coal generation will decrease, natural gas generation will increase, and renewable generation will continue to increase. The District also added more storage capacity, which will help reduce the curtailment of the renewable assets it is constructing. The Brattle team also finds the District's forecast fuel and power prices in their 2025 Corporate Operating Plan reasonable.

Fuel and Variable O&M Expenses – The fuel plan projects the District's coal, natural gas, and oil fuel costs from 2024 through 2034. These projections are based on fuel usage at individual units from 2024 through 2034 and estimated fuel costs during the same time frame. Fuel costs increase in 2025 and 2026 due to North Omaha 4-5 coal expenses before the fuel conversion is completed in 2027, at which point it starts to ramp down again and stabilizes to a large extent through 2034. Variable O&M is projected to be relatively stable through 2024, with a slight increase expected around 2030. 2024 O&M expenses were materially lower than projections due to increased outages driven by severe weather events.

Overall, the fuel plan budgeting process reflects acceptable methods currently used in the electric utility industry. The resulting expenditures for fossil fuels appear to be reasonable and necessary for the ongoing operation of the District's generating resources. While The Brattle Group was not provided with historical fuel cost information, the District's overall fuel costs are comparable with other regional utilities due to the District's purchase of low-cost wind and low fuel cost thermal resources.

Load Forecast – The District's load forecast projects the District's residential, industrial, and commercial energy consumption (load) and system peak demand from 2025 through 2034. The load forecast's uses include estimating revenues, dispatch modeling, energy trading/hedging, and future system planning. To assess model accuracy, the District's load forecasting staff compares their models' retrocasts of energy sales and peak demands against historical data. Based on the most recent forecast, net system load is forecasted to increase from 14,169 GWh in 2024 to 15,890 GWh in 2025, and peak demand is forecasted to increase from 2,843 MW to 3,036 MW.

The methods used to forecast future customer loads and system peak demand and energy requirements reflect current acceptable and defensible practices in the electric utility industry. As a result, the load forecast developed by the District's staff appears reasonable. In addition, the District's load forecast seems reasonable compared to national and regional load forecasts, given the anticipated growth in industrial loads (specifically from data centers). It is important to note that while all customer classes are expected to grow through 2028 and contribute to the growing load forecasts, data centers remain the single largest industrial customer group driving the OPPD load growth. The District's staff made some adjustments to the forecasting methodology for new large-load customers in the 2025 COP. This adjustment resulted in increased forecasts through 2029 and decreased forecasts between 2029 and 2034 relative to the forecasts prepared for the 2024 COP. We reviewed the new approach used for forecasting large loads and found it to be more objective and reliable.

The District must continue to track external economic factors such as employment growth, inflation, and interest rates, as well as the implications of these factors for the local economy. Projected rate increases based on the District's assumed economic conditions may not be sufficient to fund future programs if the actual factors deviate substantially from forecasts.

Energy Delivery (O&M and Capital Budgets) – The O&M budget is allocated across the following divisions: Transmission & Distribution Engineering, Asset Management, Grid Operations, Construction & Management and Operations Support. The last two categories make up roughly 80% of the overall Energy Delivery O&M budget, which is projected to be $102.8 million in 2025, up from $84 million in 2024. It is important to note that the actual energy delivery O&M expenses have been consistently above projections over the last five years.

The capital budget is divided into Core, Mandatory, Critical, Value-Add, and Enterprise Priority categories. The first two categories make up roughly 80% of the Energy Delivery Capital Budget, which is projected to be $239.8 million in 2025, an increase of $50.2 million from 2024.

The plans outlined in the Energy Delivery O&M and Capital Budgets appear reasonable given the District's near- and long-term goals.

Energy Production (O&M and Capital Budgets) – The District's energy production forecast projects O&M (excluding fuel) expenses, consumables, and employee headcount for 2025 and 2026. Projected planned outage costs are also provided. Direct O&M expenses for 2025 are forecasted to be roughly the same as 2024 (projected) costs, roughly $108 million. The 2025 Consumables budget is a little over $12 million, roughly $2 million higher than that projected for 2024. The full-time headcount of employees is anticipated to increase from 416 in 2024 to 456 in 2025. Additionally, we note that the total planned outage costs are $16.6 million in 2025, down from $28.8 million in 2024.

The Energy Production Capital Budget has two components: a S*ustain* budget and an *Expansion* budget. Projects under the Sustain budget aim to maintain or improve existing assets, while the Expansion budget projects support increased capacity or further economic development. The Energy Production Capital Budget is $365 million, up by $28 million relative to the 2024 budget. Continuing the historical trend of the past several years, the driver of this increase is the observed and expected load growth in the District. Expansion projects are budgeted at $299 million, while Sustain projects represent $66 million of the budget. Out of the total capital budget, new generation projects represent 78%.

The Brattle Group finds that the 2025 Energy Production (Production Operations) forecasted O&M expenses and employee headcount values are reasonable. The plans outlined in the Energy Production Capital Budget appear reasonable given the District's near- and long-term goals.

Fort Calhoun Decommissioning – The decommissioning deck outlines the timeline and path toward decommissioning, focusing on 2024 accomplishments. The timeline forecasts substantial work to be done in 2025 and 2026, bringing the project to completion. The 2025 goals are to complete the removal of components and structures within the containment structure, the removal of remaining ancillary structures, the demolition of the containment structure, and the continuation of site radiological surveys. In 2026, the goal is to achieve "Substantial Completion" of the physical work necessary to achieve the acceptable radioactivity levels mandated by the NRC and submission of the license termination package to the NRC for approval.

While Brattle's review of the decommissioning is high-level and performed without a detailed analysis, the decommissioning timeline and process appear on target. Based on the reported metrics, the District met the majority of its 2024 goals.

Technology & Security – Capital projections for 2025 are $107 million, a $19 million increase over the 2024 budget. Out of the overall budget, 73% is allocated to Enterprise Priority, which involves delivering on a large body of AMI program work, including OMS, GIS, FSM, EAM, Customer Platform, AMI (HES, MDMS and meters), CC&B Integrations and middleware modernization. The Core work represents 24% of the budget. It will be spent on Subscription-Based Information Technology Arrangements (SBITAs) renewals, the replacement of infrastructure, and the TS Strategic Asset Management Plan, which will enable funding for the replacement of existing like-for-like assets. The remaining 3% is for mandatory projects.

On the O&M side, the budget request for 2025 is $72 million, up by $7 million compared to the 2024 budget. The personnel count is projected to increase by 10, commensurate with delivering a significant body of AMI work.

The Brattle Group finds that the 2025 Technology and Security Capital and O&M budgets are reasonable given the list of “large efforts” in the 2023-2027 time frame, which was presented to our team.

AMI Program Update. Given that many of the Technology and Security investments are related to AMI deployments and functionality, we also requested an additional meeting this year to hear about AMI program updates. The District is planning to deploy advanced metering infrastructure (AMI) meters to all its customers starting in 2025 and complete the deployment by the end of 2028. We understand that the AMI minimum viable product (MVP) entails the following functions: meter-to-cash, remote connect/disconnect, meter asset monitoring, outage &OMS integration, customer portal, tamper detection, voltage monitoring, storm analysis, and reliability analysis. The projected CapEx budget for the AMI MVP is $203 million, of which $54.5 million is forecasted to be spent through the end of 2024.

We were pleased to hear that the AMI meters the District has selected for deployment have the latest technology embedded in them, which will allow customers to access disaggregated end-use information. We also understand that the District is building the broader ecosystem of AMI to maximize AMI’s potential capabilities. We strongly encourage the District to accelerate investments associated with managing big data to coincide with the timing of AMI meter deployment. Accelerating these investments will enable the District to utilize data for customer analytics and rate design implementation without further delays.

Safety & Facilities – The Master Facilities Plan outlines plans to optimize its space utilization and facility location while pursuing net zero carbon production by 2050, increasing customer satisfaction and employee retention. The total requested capital budget for safety and facility projects in 2025 is $113 million. The most significant component of this budget request is for the “integrated operations center (IOC),” at $107 million. Given that a significant portion of the District’s workforce continues to work from home fully or partially, we would encourage the District to analyze these trends for its employees before making decisions about sizing and designing office buildings and facilities.

Summary- The Brattle Group, in its review, finds the District’s 2025 Corporate Operating Plan to be sound and well-supported. The expenditures anticipated by the District are reasonable and of the type that a utility following prudent utility practices would expect. In addition, the projected financial results reflected in the 2025 Corporate Operating Plan provide for accomplishing the District’s minimum performance objective for debt service coverage.

We understand that the District's senior management has already reviewed and approved the 2025 Corporate Operating Plan. However, we would like to raise additional caution about the expected impact of hyperscalers and other large loads. The District's budgeting process substantially relies on the expected load growth from these data centers and other large loads. While these loads are likely to materialize as projected in the near term, the District's financial reliance on these loads requires it to carefully consider the hyperscalers' key priorities for their location decisions in order of importance: speed-to-capacity, reliability, cost, and access to green power. These expectations imply that hyperscalers will move to regions that can meet more of their prioritized requirements. Therefore, OPPD should not take such load growth for granted and should continue to innovate to meet these expectations.

The Brattle Group has used all of the information the District provided to us in our recommendations and considerations put forth to the District. Although we believe the sources used to support our analysis are reliable, we have not independently verified them. The District's assumptions have been reasonably drawn for this annual review and were developed in a manner consistent with industry practice. However, actual future conditions may diverge from those assumed, and we cannot offer any assurances about the District's assumptions. As a result, observed results may vary from those projected due to differences between actual future conditions and the information the District provided to The Brattle Group to reach its recommendations and conclusions.

We appreciate the opportunity to serve the District. We are happy to discuss any questions concerning this review at your convenience.

Respectfully yours,

Philip Q. Hanser
The Brattle Group
Principal Emeritus

Sanem Sergici, Ph.D.
The Brattle Group
Principal

Board of Directors
Omaha Public Power District
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

November 14, 2024

Ladies and Gentlemen:

I. Background

The Omaha Public Power District ("the District") proposes an average general rate increase of 5.9 percent effective January 1, 2025. Consistent with its policy of aligning rates with costs, the proposed percentage increase in base rates varies among customer classes. In addition, the District proposes updating the fuel and purchase power adjustment ("FPPA") factor, resulting in an increase from those revenues of 0.4 percent. The combination of the general rate increase and the increase of the FPPA factor results in an overall impact of increasing average rates by 6.3 percent.

II. Discussion

OPPD's proposed increase of 6.3 percent is based on the District's cost of service study ("COSS"). The primary purpose of a COSS is to allocate the costs of providing service to different customer classes based upon cost causation principles and the costs that each customer class imposes on the system. It aims to determine the portion attributable to each Rate Class under the principle of cost-causation. We have worked closely with the District on its COSS, including reviewing the methodology and associated spreadsheets.

The district is also proposing to increase the FPPA factor from the current $0.00413/kWh to $0.00457/kWh. This rate factor will be applicable to all rate classes except Rates 239 and 261M.

In addition to the rate increase, the proposed rates reduce the energy rate gap between each of the block rates, where applicable, in the non-summer months. For example, the difference in energy rates between the last and penultimate block for Rate 110 today is ¢0.56/kWh. The proposed rate reduces this gap to ¢0.11/kWh. This will allow a smoother transition to completely flattening of the block rates that is planned for in 2025.

III. Findings

We have reviewed the District's proposed rate increase and the accompanying calculations. The District's proposal ensures that the revenue requirement for each rate class is as close to cost-based as possible while ensuring that no class faces a rate shock, resulting in an acceptable balance between cost-reflectivity and bill stability for customers.

Furthermore, the proposal to shrink the gap between the non-summer block rates for 110, 115 and 230 is also reasonable. This decision to reduce the gaps between the different blocks also promotes gradualism in anticipation of the eventual elimination of block rates, scheduled to take place in the Fall of 2025. It will provide customers enough time to alter their usage in response to the modified block rates beginning January 2025 before the blocks are eliminated altogether following Summer 2025. The District has also confirmed that bill impacts at various usage levels as a result of the change in rate design are reasonable relative to the overall rate increase for the customer class. In summary, we find the proposed rate changes to be fair, reasonable and non-discriminatory.

IV. Recommendation

We recommend the Board adopt the proposed rate increases based on the COSS results, proposed rate adjustment methodology and the FPPA factor resetting.

Sincerely,

Dr. Sanem Sergici

PRINCIPAL | BOSTON

Exhibit A
Proposed Rate Adjustments
January 1, 2025

	Proposed Revenue Increase ($ M)	Proposed Percent Increase
	Total	Total
Residential		
Residential	$35.8	8.3%
Conservation (Heat Pump Rate)	$6.1	8.4%
Total Residential	$41.9	8.4%
Commercial		
Irrigation Service	$0.1	3.0%
General Service Non-Demand	$6.5	8.4%
General Service Small Demand	$9.9	3.5%
Total Commercial	$16.5	4.5%
Large Commercial/Industrial		
General Service – Large Demand (over 1,000 kW)	$8.9	7.7%
Large Power – Contract (over 10,000 kW)	$3.7	8.6%
Large Power (over 20,000 kW)	$5.8	7.2%
Large Power – High Voltage Transmission Level – Market Energy	$7.1	3.0%
Total Large Commercial/Industrial	$25.5	5.4%
Lighting		
Dusk-to-Dawn Lighting	$0.2	8.2%
Municipal Service – Street Lighting	$1.6	8.1%
Municipal Service –Traffic Signals and Signs	$0.0	8.5%
Total Lighting	$1.8	8.1%
Municipal Service	$0.3	8.6%
TOTAL*	$86.0	6.3%

* Totals may not add due to rounding.

Exhibit B
Proposed Service Regulations and Schedules Revisions
January 1, 2025

Rate Schedules	Description	Proposed Provision(s)
Rate 236	Dusk-to-Dawn Lighting	Add 2 new LED Lamp Types (33W, 108W).
Rider 467 / 467H, 467E / 467V/ 467L	Curtailable Riders	Close riders to new customers and remove automatic renewal feature. Curtailment program will be administered as a Product Program effective January 1, 2025 for all new customers. As contracts for existing customers expire, they will be eligible to move to the product offering.
Rider 470I	Tenant Attachment Fee	Update annual fee from $13.70 to $16.00.
Rider 480	Residential Surge Guard	Retire offering effective January 1, 2025. Existing customers will be transferred to Product Program.
Rider 481	Commercial Surge Guard	Retire offering effective January 1, 2025. Existing customers will be transferred to Product Program.
Rider 490	Economic Development	Retire offering effective January 1, 2025. No existing customers.
Rider 499	Green Sponsorship – GSP	Retire offering effective January 1, 2025. No existing customers.

Service Regulations & Schedules

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OPPD
Omaha Public Power District

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INTRODUCTION AND DEFINITIONS

Introduction

Omaha Public Power District (OPPD) proudly provides affordable, reliable and environmentally sensitive energy services to Customers across a 13 county, 5,000 square mile service territory. Formed in 1946, OPPD is a public power utility and is governed by a publicly elected Board of Directors. The costs of providing service determines the Rates and Riders in this document.

These Service Regulations will guide both you and OPPD throughout your experience as a Customer, including the requirements of both OPPD to deliver and you to receive Electric Service. The OPPD Board of Directors has officially adopted these Service Regulations, and they may be revised, amended, superseded, or repealed at any time by the Board. Where applicable within these Service Regulations, reference will be made to additional OPPD documentation that provides more detailed requirements.

As a public power district in the State of Nebraska, OPPD has a defined Service Area and operates under applicable state laws, including the following:

Statutory Authority

Section 70-655, Revised Statutes of Nebraska, as amended, states that the Board of Directors of the Omaha Public Power District shall have the power and be required to fix, establish, and collect adequate rates, tolls, rents, and other charges for electrical energy and for any and all other commodities supplied by OPPD, which rates, tolls, rents, and charges shall be fair, reasonable, nondiscriminatory, and so adjusted as in a fair and equitable manner to confer upon and distribute among the users and Customers of commodities and services furnished or sold by OPPD for the benefits of successful and profitable operation and conduct of OPPD's business.

Section 70-1017, Reissue Revised Statutes of Nebraska, 1943, as amended, states any supplier of electricity at retail shall furnish service, upon application, to any applicant within the Service Area of such supplier if it is economically feasible to service and supply the applicant. This "obligation to serve" requires OPPD to make substantial investments in generation, transmission, distribution, and other property, facilities, and equipment, and the economic feasibility of such investments are based on the principle that the rates and other charges for Customers requesting such service will recover the cost of such investments and confer on OPPD and its customers the "benefits of a successful and profitable operation and conduct" of OPPD's business, as provided in Section 70-655. This "obligation to serve" also means that the Customer has an obligation to purchase and pay for service from OPPD, during the operation of the Customer's facilities within OPPD's service territory, so that OPPD may recover the cost of the investments made to provide Electric Service.

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Using This Document

Customers have differing Electric Service requirements based on their usage. OPPD has several rate offerings varying in structure, price, and complexity available to Customers to meet their needs. This document provides the specific Board of Directors approved language for each of these Rates, Service Regulations, and Riders. Please note that capitalized terms used in the Service Regulations are defined in the Definitions section.

To make it easier to find information within this document, the three main sections of this document are described below.

- SERVICE REGULATIONS
  This section informs the Customer of rules and regulations required to receive Electric Service from OPPD.

- RATE SCHEDULES
  This section outlines the available rates that Customers may select for receiving service from OPPD based on their usage characteristics and equipment requirements. These Rate Schedules include the billing components that describe the rates, fees, and/or charges for Electric service received from OPPD. All Customers must be covered by one of these Rate Schedules per Point of Delivery.

- RIDER SCHEDULES
  This section outlines all Rider Schedules applicable to Customers who receive service on an OPPD Rate Schedule. Riders can be elective or required based on Customer's Electric Service requirements and usage characteristics. Riders are additional fees, credits, or other charges where applicable to Customers based on the outlined criterion.

Understanding Billing Components

While there are multiple billing components, most rates have three primary billing components: Monthly Service Charge, Energy Charge, and Demand Charge. These components reflect the type of Electric Service provided to the Customer and are used to calculate a total electric bill. Not all rates have all three of these components and some rates have additional components based on their particular structure.

- MONTHLY SERVICE CHARGE
  This charge is a fixed amount required for a Customer to receive Electric Service. This amount does not vary with the amount of energy used. As an example, the Monthly Service Charge includes items such as Customer service, metering, and the infrastructure that connects a Customer to the electric grid.

- ENERGY CHARGE
  This charge varies based on the total amount of energy, measured in kilowatt-hours (kWh), used by a Customer over a particular time interval. As an example, this pays for items such as the fuel required to produce electricity and renewable energy purchases.

- DEMAND CHARGE
  This charge is based on the highest amount of power, measured in kilowatts (kW), required by a Customer at any particular moment in time. This charge covers costs to maintain infrastructure, such as power plants and transmission lines, whose sizing must meet all of OPPD's Customers' maximum usage year-round. For rates without Demand Charges, the Energy Charge covers these costs.

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Table of OPPD Rate Schedules and Applicable Rider Schedules

Customer Categories	Rate Schedules (subject to applicability)		Billing Components				Rider Schedules (subject to applicability, requirements, or other charges)
			Service Charge	Energy Charge	Demand Charge	Other	
Residential Service	**110**	Residential Service	●	●			355, 461, ~~480,~~ 483, 500
	115	Residential Conservation Service	●	●			355, 461, ~~480,~~ 483, 500
Small General Service (Less Than 1,000 kW)	**226**	Irrigation Service		●		●	355, 461, 483
	230	General Service Non-Demand	●	●			355, 461, ~~481,~~ 483, 500
	231	General Service – Small Demand	●	●	●		355, 461, 462, 464, 467 (E, H, L, V), 469, 469S, ~~481,~~ 483, 500
Large General Service (More than 1,000 kW)	**232**	General Service – Large Demand	●	●	●		355, 461, 462, 464, 467 (E, H, L, V), 469, ~~481,~~ 483, 484, ~~490, 499,~~ 500
	245	Large Power –~~-~~ Contract	●	●	●		355, 461, 464, 467 (E, H, L, V), 469, 483, 484, ~~490, 499,~~ 500
	250	Large Power	●	●	●		355, 461, 464, 467 (E, H, L, V), 469, 483, 484, ~~490, 499,~~ 500
Very Large General Service (Transmission Interconnected)	**261M**	Large Power – High Voltage Transmission Level market Energy	●	●	●	●	355, 464, 467 (E, H, L, V), 483, 500
Lighting Service	**236**	Private Outdoor Lighting				●	461
	350	Municipal Service – Street Lighting				●	461
	351	Municipal Service – Traffic Signals and signs		●		●	461
Municipal Service	**357**	Municipal Service	●	●	●		355, 461, 484

Other relates to specific charges related to specific applications such as irrigation and lighting.

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DEFINITIONS

Auxiliary Generating Unit	A Customer operated generating unit that is used only to provide standby power to replace power normally supplied by a Primary Generating Unit.
Billing Demand	Demand as calculated in the Determination of Demand section and applied to the bill of a Customer who takes service under OPPD's Demand Rate Schedules.
Cogeneration	Concurrent production of electric energy and thermal energy used for heating or cooling purposes.
Curtailable Load	A Customer's Load contracted to be reduced during periods identified by OPPD.
Curtailable Customer	A Customer who has contracted to curtail Load according to the provisions of Rate Schedules 467, 467E, 467H, 467L or 467V.
Customer	Any person, partnership, association, firm, corporation (public or private), limited liability company, governmental agency, or other entity taking service from OPPD at a specific location, whether the service at that address is in their name or some other name.
Customer Owned Generation (COG)	Distributed Generation (DG) not owned and operated by a Nebraska electric utility, but typically owned and operated by a Customer of the utility.
Demand	The instantaneous rate at which energy is delivered to an electrical Load and measured in either kilowatts (kW) or kilovolts-amperes (kVA).
Demand Meter	The device(s) and any auxiliary equipment, including Demand registers, required to measure the Electric Service or to measure the 15-minute period of highest electrical energy consumption supplied by OPPD to a Customer at a Point of Delivery.
Demand Response (DR)	Customer adjustment or control of their electrical Load in response to a signal from the electric utility. Customers with DR capability are typically voluntary participants in special utility DR rate programs.
Demand Side Management (DSM)	See Load Management.
Distributed Energy Resource (DER)	Includes Distributed Generation (DG) and may generally include Load Management and Demand Response technologies.
Distributed Generation (DG)	Electric generation and/or Energy Storage technologies, generally characterized as 'distributed' in nature and interconnected to a utility distribution system at or near Customer Loads. DG may consist of one or more generators or resources. Energy sources used by DG to generate electricity may be from renewable or non-renewable sources.
Electric Service	The service by which OPPD supplies power to a Customer's Point of Delivery, either by overhead or underground wires.

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Emergency Generating Unit	A Customer-operated generating unit that is normally only used during an outage of the Electric Service from OPPD, for testing, or during curtailment by a Curtailable Customer.
Energy Storage	Technologies, including but not limited to battery storage, capable of controlled charging and discharging of electrical or other forms of energy, which may be applied in a number of ways to interact with an electrical system.
Federal Holidays	An authorized holiday recognized by the United States government.
NERC Holidays	North American Electric Reliability Corporation (NERC) defined holidays which include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.
General Service	Service to any Customer for purposes other than those included in the applicability provisions of the Residential Rate Schedules.
Load	Devices or appliances which consume electrical energy to power electronics or to produce light, heat, cooling, sound, motion/mechanical energy or other intended outcomes. Load can also refer to the cumulative electric energy consumed at any given point in time by a group of such devices or appliances.
Load Management	The process of adjusting or controlling a Customer's electrical Load to assist a utility in achieving a balance between its Customers' Demands and its electrical energy, as opposed to adjusting power station output to match the varying requirements of Customer Load. Also referred to as Demand Side Management (DSM).
Meter	The device(s) and any auxiliary equipment required to measure the Electric Service supplied by OPPD to a Customer at a Point of Delivery.
Owner	The person(s) having Ownership of the Premises or acting as an agent for the Owner.
Point of Delivery	The physical location at which OPPD supplies Electric Service to a Customer and which, unless otherwise agreed upon between OPPD and the Customer, shall be the point where OPPD's Service Wires are joined to the Customer's service terminals.
Power Factor	The ratio obtained by dividing the Customer's maximum kilowatt Demand by the Customer's maximum kilovolt-ampere Demand.
Premises	Building or tract of land identified in a deed stating the details of the conveyance of the property. For OPPD, the Premises details the location of building or tract of land at which Electric Service is supplied by OPPD.
Primary Generating Unit	A Customer-operated generating unit used to supply electrical Load within the Customer's facility, which operates in parallel to OPPD's system, and is not an Emergency Generating Unit.

Primary Service	Single-Phase or ~~three~~Three-phase service taken from OPPD's system at a standard available voltage above 11,000 volts, provided there is only one transformation involved from OPPD's transmission voltage (above 60,000 volts) to the service voltage.
Qualified Generator	Generators that qualify for net metering as set forth in the Nebraska Revised Statutes. Qualified Generators are interconnected, in accordance with an interconnection agreement, behind a Customer's service Meter located on the Customer's Premise with an aggregate nameplate capacity of 100 kW or less that uses as its energy source: methane, wind, solar, biomass, hydropower, or geothermal and is controlled by the generation owner.
Rate Schedule	Outlines the rate(s), fees, and charges for, or in connection with, Electric service received from OPPD.
Residential	House, trailer, apartment, flat or unit of a multi-family dwelling that is equipped with cooking facilities. Electric Service for one single-family dwelling may be served on a Residential Service Rate Schedule.
Rider Schedule	Outlines the rate(s), fees and charges used in conjunction with the Customer's electrical Rate Schedule. Rider Schedules can be optional or required based on Electric Service requirements.
Schedule	Rates, charges and other provisions under which service is supplied.
Seasonal Energy Efficiency Ratio (SEER)	The total cooling of a central air conditioner or heat pump in British thermal units (Btu) during its normal annual usage period for cooling divided by the total electric energy input in watthours during the same period as rated by the American Refrigeration Institute (ARI) Guide.
Secondary Service	Single-Phase or ~~three~~Three-~~p~~Phase service taken from OPPD's system at a standard available voltage below 11,000 volts, provided the conditions defined under "Primary Service" are not applicable.
Service Area	The geographic area in which OPPD provides Electric Service.
Service Wires	The wires, owned by OPPD, connecting OPPD's distribution system to a Customer's service terminals.
Small Power Production	A facility with less than 80,000 kilowatts of installed capacity that produces electricity from such primary energy sources as biomass, waste, or renewable resources including wind, solar, geothermal, and hydroelectric energy.
Standby Service	Service to supply electrical energy to serve a Customer's Load that is usually served by the Customer's generating unit.

SERVICE REGULATIONS

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STARTING SERVICE

Application for Service

An applicant may make a written, verbal, or electronic application to OPPD for service(s) and will be required to provide the following information:

- Social security number, or
- Federal tax identification number

If the social security or federal tax identification numbers are unavailable, a birthdate in combination with verifiable, government-issued identification can be used.

OPPD may require proof of occupancy before application of service; additionally, the Customer may be required to pay a billed or unbilled debt, identified by OPPD as the applicant's responsibility, before the establishment of service.

OPPD relies upon the fact that the applicant is authorized to make the application, is acting in good faith, and is providing valid and accurate information. An applicant who fails to comply with this section may be denied service.

Upon application for service at a Premises, the Customer will be charged an activation fee. This fee will be included in the next monthly bill.

Account Security

OPPD may require the Customer to maintain a cash deposit or other form of account security acceptable to OPPD that is deemed adequate by OPPD to secure payment of an account or accounts for Electric Service and related services.

Application for Rate Schedules

When a Customer applies for service, they must indicate the Rate Schedule for which they are applying. A Customer must remain on the same OPPD Rate Schedule for a minimum of twelve (12) consecutive months before service can be received under another OPPD Rate Schedule at a specific Premises. After the twelve (12) consecutive months, the Rate Schedule will remain in effect until the Customer requests service under another Rate Schedule. If the Customer notifies OPPD of a change in their appliances, equipment, or usage, which would permit the application of another Rate Schedule, the Rate Schedule under which service is currently supplied may be changed within the twelve (12) months to meet the Customer's modified conditions.

If a Customer is eligible to take Electric Service from OPPD under one or more applicable Rate Schedules, the Customer is responsible for the selection of their Rate Schedule, and it will not be applied retroactively. Any new Rate Schedule will become effective after the next Meter reading cycle.

OPPD will furnish a Customer, at their request and without charge, all reasonable information and assistance in choosing the most advantageous Rate Schedule. The Customer may opt for a new Rate Schedule, contingent upon OPPD approval, if significant changes in the Customer's Load conditions or equipment occur.

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The following Rate and Rider Schedules are subject to the Customer's selection:

- Rate Schedules Nos. 115, 231, 232, 245, 250, and 261M
- Rider Schedules Nos. 355, ~~467, 467E, 467L, 467V,~~ 469, 469S, ~~480, 481,~~ 483, 484, ~~490, 499,~~ and 500

The service supplied under the Rate Schedules is made subject to the provisions and specifications contained in the Service Regulations.

These Service Regulations shall apply to all services supplied by OPPD.

SERVICE CONTRACT

OPPD will supply Electric Service to a Customer under the terms and conditions of the applicable Rate Schedule(s) and Service Regulations. OPPD, at its discretion, may also require an individual service contract for a Customer's Electric Service. By accepting Electric Service from OPPD, the Customer agrees to comply with OPPD's Rate Schedule(s) and Service Regulations.

Unlawful Use of Service

For diversion of service as defined in Nebraska statues, OPPD may pursue any or all civil or criminal statutory or common law remedies.

Tampering with, bypassing, altering, damaging, misusing or interfering with OPPD's Meter installation or its proper functioning will result in disconnection of service and prosecution under applicable laws. The Customer, at the applicable rate, will be liable for energy not recorded on the Meter, plus all expenses incurred by OPPD as a result of the unauthorized act(s).

Refusal of Service

OPPD may decline to service an applicant or Customer and disconnect services in certain situations such as:

- Failure to comply with these Service Regulations and/or with any applicable governmental regulations
- Installation is known to be hazardous or of such character that satisfactory service cannot be provided
- Refusal to meet account security requirements
- Presented fraudulent documentation or information to establish an account
- OPPD has discovered Meter tampering, theft or diversion of service
- The applicant has applied for service at a Premises where the previous Customer received service and is indebted to OPPD and:
    - The new application for service is made to assist the previous Customer evading or avoiding payment for the indebtedness or
    - The previous Customer no longer occupies the Premises, but the applicant is found to have occupied the Premises and benefitted from service prior to the date of application and has refused to pay charges incurred during such occupancy

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CONDITIONS OF SERVICE

Easements and Right Of Way

Customer, without expense to OPPD, will make or procure the necessary easements, satisfactory to OPPD, for OPPD's lines, routes or extensions and all the equipment required to provide service to the Customer.

Tree Trimming

Customers shall permit OPPD to remove or trim trees and other vegetation, including the removal of limbs, to the extent that trimming is reasonably necessary to prevent interference with OPPD's transmission and distribution power lines and other electric equipment or to protect the safety of the Customer, the general public, or OPPD's property. Any trimming of trees and vegetation on the Customer's Premises that interfere with OPPD's Service Wires shall be the responsibility of the Customer and enforceable by OPPD as provided by law.

OPPD and Customer Roles and Responsibilities

OPPD will designate a point on the Customer's Premises where service will be delivered. Customer will provide and maintain adequate support and protection for attachment of OPPD's overhead or underground Service Wires on their Premises and will be responsible for any damages caused by the failure of or defect in such support or protection.

The Customer shall furnish if requested, suitable space on the Customer's Premises for OPPD's transformer equipment, as well as switching and capacitor equipment.

OPPD will furnish metering equipment required to measure the service supplied and will keep said equipment accurate within reasonable limits. The Customer will provide, without cost to OPPD, adequate space in a suitable location for OPPD's metering equipment.

Customer will secure all necessary permits for wiring on the Customer's Premises, will install such wiring in compliance with the National Electrical Code and all applicable laws, regulations, and ordinances, and will pay all inspection fees. OPPD will not be responsible for inspection of wiring on the Customer's Premises but reserves the right to require inspection before connecting service. OPPD may postpone the actual construction of its facilities to a Customer until Customer's wiring has been approved by the proper inspection authorities, has met OPPD's requirements, and is ready for connection to OPPD's system.

Unless otherwise agreed in writing, OPPD will retain title to all property installed or supplied by OPPD on a Customer's Premises and said property may be removed by OPPD at any time. The Customer will safeguard and provide adequate protection for OPPD's property (including poles, transformers and metering equipment) located on Customer's Premises and will maintain clear and safe access at all reasonable times. The Customer must keep the area around OPPD's equipment free of obstacles to facilitate OPPD operations and maintenance. This cleared area is to extend at least three (3) feet from each piece of equipment unless otherwise noted on the individual

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component.

Redundant Service

Customers taking Electric Service under any of OPPD's Rate Schedules will not receive redundant Electric Service at the Point of Delivery unless they are applicable and choose to take service under Rider Schedule No. 484 – Supplemental Distribution Capacity Rider.

Power Factor Equipment

OPPD reserves the right to measure the Customer's Power Factor. If the resulting measurement is less than the ratio specified in the Customer's applicable Rate Schedule, OPPD may require the Customer to provide facilities for OPPD to install kilovolt ampere metering. OPPD may increase the Customer's kilowatt Demand for billing purposes under the Customer's applicable Rate Schedule.

Customers with equipment or facilities having inherently low Power Factor characteristics should consider installing additional equipment to improve the Power Factor to avoid an increase in their bills and minimize losses on their electrical system.

Electrical Problems Caused by the Customer

The electricity usage or equipment operations of any Customer shall not cause electrical disturbances or problems for other Customers. Disturbances or problems include but are not limited to: steady-state voltage excursions beyond recognized limits (the latest revision of ANSI C84.1), transient disturbances, magnetic field interference, stray current/voltage, radio frequency interference, and Customer-G~~g~~enerated harmonics exceeding recognized limits (the latest revision of IEEE 519). It is the Customer's responsibility to take corrective action to comply with all applicable standards or pay the costs incurred by OPPD to take appropriate corrective action as a result of an electrical disturbance or problem. Failure, inability or refusal to remedy or rectify OPPD's concerns to conform to such limits, within a commercially reasonable amount of time, may result in disconnection of service.

OPPD Responsibility

OPPD will supply Electric Service consistent with prudent utility practice and will endeavor to provide, but does not guarantee, uninterrupted service and is not responsible for any loss or damages sustained by a Customer as a result of outages on the system, including but not limited to service disruptions that are caused, contributed to, or exacerbated by:

- Weather
- Repairs or maintenance
- Alterations
- Unavailability of supply
- Conditions of Customer's Premises are dangerous to persons, property, or service to others
- Nonpayment by the Customer for amounts due
- Customer's failure to provide means of access for obtaining regularly scheduled readings of the Meter or for testing OPPD's equipment
- Customer' failure to protect OPPD's equipment from theft, abuse, or vandalism
- OPPD's actions to prevent fraud or abuse of OPPD property

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- Outages caused by third parties or animal interfer

Customer waives claim for, and hereby releases and discharges OPPD from claims for, and shall indemnify and save harmless OPPD from, any and all loss and damage arising from an interruption of service, including loss or damage caused by the negligence of OPPD. Customer further waives claim for, and hereby releases and discharges OPPD from claims for, and shall indemnify and save harmless OPPD from, any and all loss and damage arising from or on account of injury to persons (including death), or damage to property on the Premises of a Customer or under a Customer's control, unless such loss, damage, or injury is the natural, probable and reasonably foreseeable consequence of OPPD's negligence, and such negligence is the sole and proximate cause thereof.

Charge for Service

When a Customer applies for service which necessitates an extension of OPPD's electric facilities to serve the Customer, OPPD reserves the right to collect from the Customer, in advance, part or all of the cost of such extension when:

- The anticipated revenue to OPPD is not in proportion with the cost of such extension
- The extension is required because of abnormal operating characteristics of the equipment to be operated by the Customer
- The extension is required for emergency or special services
- The extension is not the least cost means of providing such services

A charge will occur for each temporary overhead or underground single-phase service connection, consisting of Service Wires and a Meter. When more than Service Wires and a Meter are required, the Customer will pay for the work done by OPPD on a contract basis.

Charge for Re-Establishing Service

The charge for service and the reconnection charge required by OPPD's Service Regulations will not apply to the re-establishment of service after the destruction of the Customer's Premises resulting from explosion, fire, flood or storm. In such cases, the equivalent service will be re-established at the Customer's option at a temporary or permanent location. If the damaged Premises are repaired within a reasonable time, not to exceed two years, the charges defined will not apply when the Customer moves back to the Customer's original location.

Transfer of Service

Contracts or service with OPPD will not be assignable or transferable by the Customer without the written consent of OPPD.

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RESALE, REDISTRIBUTION, OR EXTENSION OF ELECTRIC SERVICE

The resale, redistribution or extension of Electric Service will not be allowed in OPPD's service territory except under conditions identified in these Service Regulations.

The redistribution of electricity by a Customer from electric vehicle charging, truck stop, campground, or other similar plug-in power equipment will not be considered the resale of electricity as long as the charge for the plug-in service is not sold on a metered kilowatt-hour or kilowatt basis. The Customer is not prohibited from recovering the cost of the electric vehicle charging equipment or plug-in power equipment and related infrastructure.

If the Customer is qualified to redistribute electricity to individual tenants, the Customer must ensure that the total electricity revenue recovered is no more than the total cost of electricity as billed by OPPD to the Customer.

This regulation does not apply to municipalities purchasing wholesale energy under power contracts.

TRANSFER OF DEMAND

Historical actual Demand will remain in effect on accounts where a rate change has been executed. All aspects of the new rate will be applied using the historical actual Demand data.

Historical actual Demand will remain in effect on accounts where a name change has been requested, and the Customer's tax identification number remains the same.

COMBINED RESIDENTIAL AND GENERAL SERVICE

A Customer in a single-family dwelling, parts of which are used for business purposes, may purchase service under a Residential Rate Schedule when the floor area of the part used for General Service purposes does not exceed 25% of the combined Residential and General Service floor area.

EXCEPTIONS TO "ALL SERVICE" REQUIREMENTS

Customers with a Rate Schedule that requires one Meter for all the Customer's services may maintain separate Meters in the following situations:

- When a Customer is required by law to provide separate wiring circuits for emergency lighting service, sprinklers or alarm systems, and this separate service cannot feasibly be metered with the remainder of the Customer's service

- When a Customer operates X-ray, welder or other equipment producing abnormal voltage fluctuations or other power quality issues, OPPD may require metering that equipment separately.

- When a Customer occupies two (2) or more spaces within the same building, where these spaces are separated by firewalls or intervening spaces, or are on different floors, and are not interconnected by private doors, passages, or stairways, separate Meters, as allowed by law, may be used for each space.

In each of the above cases, the separately metered special service shall be billed under an

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applicable Rate Schedule.

DISTRIBUTED ENERGY RESOURCE (DER) / DISTRIBUTED GENERATION (DG)

To ensure the safety of OPPD personnel and the public, and to protect the service of other Customers, a Customer who operates their own electric generating equipment and/or Energy Storage system is required to comply with all OPPD safety, metering, interconnection, and operation requirements. No connection will be made between generation and/or Energy Storage equipment and the service lines of OPPD without specific inspection and approval by OPPD. Any unapproved installation shall be grounds for immediate disconnection of OPPD's service.

OPPD will make its requirements for DER/DG compliance available upon request. OPPD requirements for compliant DER/DG interconnections are subject to change by OPPD.

Energy Storage systems can be applied and utilized by a Customer in a variety of ways. Depending upon how Energy Storage systems are installed and operated by a Customer, OPPD may interpret and consider Customer Energy Storage systems to be equivalent to generating units, or equivalent to other OPPD regulated equipment or activities, for all purposes in the application of OPPD Service Regulations. OPPD will also consider the operation of Energy Storage and the originating source of energy stored in determining Customer eligibility (or ineligibility) to participate in various OPPD rate programs.

Unless otherwise specified in the applicable Rate Schedule, the Customer will provide or reimburse OPPD for necessary grid or service modifications for the interconnection of generation or Energy Storage.

A Customer's failure to notify OPPD of the operations of units within the Customer's facility that meet the conditions of Rider Schedule No. 464 will result in:

- Application of the Excess Demand Charge as specified in Rider Schedule No. 464 to the combined nameplate rating of the units and,
- Retroactive billing of the Excess Demand Charge for the entire period such units were in operation.

METERING

Metering equipment must be located on the exterior of new and rewired construction. OPPD may grant exceptions under certain circumstances.

Separate Billing for Each Meter

When a Customer requests OPPD to supply service to their Premises at more than one Point of Delivery, the service measured by the Meter at each Point of Delivery will be considered a separate service, and Meter readings will not be combined for billing purposes.

When it is impractical, uneconomical, or undesirable to a Customer to accept the standard OPPD single Point of Delivery service, then at the option of OPPD, multiple service(s) may be allowed. The Customer is required to compensate OPPD for the additional construction cost.

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Master Metering

Master metering is one Meter that measures consumption to more than one Premise and meets each of the following criteria:

- The Customer is responsible for the installation and maintenance of all distribution equipment required to serve the facility on the Customer's side of the master Meter
- Premises must be owned by the same person or entity. If commercial or industrial, the business must operate as one integral unit under the same name
- Services must be "single building" or "adjacent buildings"
- Service must feed all buildings at the same voltage

A "single building," as used in this regulation, refers to a freestanding facility. Buildings that are connected by a walkway that includes space used for offices or other retail service facilities are considered a single building. Buildings connected by walkways for pedestrian traffic only are not considered part of a single building.

"Adjacent buildings," as used in this regulation, includes directly adjoining buildings or buildings directly across a street, alley or other public way, but does not include buildings separated from the Customer's places of business by intervening structures. The adjacent buildings must be used to carry on parts of the same commercial or industrial business, and the business must operate as one integral unit under the same name. All such service is to be used by the Customer and served through one Meter.

The Customer will also be billed on the appropriate General Service Rate Schedule.

Totalization of Meters

For Commercial and Industrial Customers who have multiple electrical Points of Delivery serving the Customer's facility, a Meter will be installed at each Point of Delivery. Totalizing across Meters to a Customer's facility to calculate the Customer's service costs will be allowed if the Customer's service design meets the following criteria:

- Customers requesting the totalizing of their Loads at multiple Points of Delivery must have the same Federal Tax ID #
- Service must be three-phase
- Service must serve building(s) at the same voltage
- Service must be a single building, or buildings that are directly next to each other on the same side of the street, with no other structures between them.

"Totalized" metering, as used in this regulation, involves the interconnection of all Customer Point-of-Delivery Meters through wiring, electronic communication, or merging of Meter readings in software to effectively create one metering system and one combined Customer account for billing purposes. The resulting metering system would read consumption, simultaneous peak Demand, and other characteristics for all Points of Delivery as a combined whole.

Customers who totalize their Load will be required to pay for the installed costs of the second service. For additional information regarding the totalization of individual Meters, please contact OPPD's Customer Service Department.

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Unmetered Service

Unmetered service is supplied only under the Rate Schedules providing municipal service for street lighting, traffic signals and signs, and private outdoor lighting.

Exceptions:

- *Emergency Sirens*: At OPPD's discretion, unmetered service may be supplied to governmental agencies for emergency sirens. The Customer will be billed monthly for the minimum charge under the applicable General Service Rate Schedules.

- *Other*: At OPPD's discretion, where the installation of metering equipment is impractical or uneconomical, and with the agreement of the Customer, unmetered service may be provided to Customers with fixed, permanently installed Loads. The monthly bills will be computed based on estimated kilowatt-hour use.

BILLING

Billing and Meter Reading

OPPD will normally read the Customer's Meter monthly. Bills will be generated using the applicable Rate Schedule at approximately one-month intervals based on the actual or estimated Meter reading. For all Customer's, the monthly billing period will usually be between 25 and 35 days. First and final bills for a service location or bills with less than 25 days or greater than 35 days will be prorated to reflect the number of days in that billing period.

When OPPD does not read the Meter, OPPD will issue an estimated bill. The Customer may be contacted to arrange a time for OPPD to read their Meter if there have been three (3) consecutive months of estimated Meter readings. All Meters will be read at least once every twelve (12) months.

Taxes

OPPD is required to collect and remit sales tax per applicable law. The total of all charges for service under the Rate Schedules will include applicable existing state and municipal taxes, any new or additional taxes, or increases in the rates of existing taxes.

Billing Terms and Conditions

The Customer's bill payment must be received on or before the due date designated on the bill or a late payment charge will be assessed. The late payment charge will be calculated as 4% of the billing components and any applicable taxes. Failure to receive a bill does not entitle the Customer to have the late payment charge waived. If a Customer's account becomes delinquent, the Customer is subject to OPPD's disconnection of service process, based on Nebraska Revised Statute 70-1605 or its successor, and all applicable fees; outlined in Rate Schedule No. 470 – General – Customer Service Charges.

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OPPD has the right to transfer any delinquent bill balance to any other Premises or OPPD account for which the Customer is or becomes responsible in any manner, or any other Premises or OPPD account at or from which the Customer receives Electric Service. If a balance due for service at any previous address of a Customer is not paid within 15 days after ending service at such address, the balance will become delinquent, and service at the current address covered by the account may be disconnected.

Service disconnected for delinquency will not be reconnected until all delinquent charges are paid or, at the discretion of OPPD, acceptable payment or account security arrangements are made.

Customer Disconnect and Reconnect at a given Premises within a 12-Month Period

In the event a Customer's service has been disconnected and has been reconnected within twelve (12) months of the service termination, the Customer will be charged the minimum monthly charge for the preceding twelve (12) months, or any part thereof.

Owner/Landlord Responsibilities

The Owner will be responsible for interim service at Premises when the Owner fails to disconnect utility service between tenancies. OPPD will bill the Owner for any unbilled usage. If the Owner wants the Electric Service disconnected automatically in the event an occupant or tenant terminates the Electric Service, the Owner must complete a Service Disconnection Form or a Landlord Contract Form and file it with OPPD.

Billing and Payment Options

Payment Options: Please see OPPD.com for billing and payment options. OPPD will accept bank card payments for several Rate Schedules. OPPD will not accept bank card payments for Customers on General Service Rate Schedules other than No. 226 and 230.

Level Payment: OPPD's Level Payment Plan will be made available to Customers receiving service on Rate Schedules Nos. 110, 115, 230 and 231 who have an acceptable payment history with the OPPD. The Customer must comply with the conditions of the regular Rate Schedule and any applicable rate riders. Customers served under Rate Schedules Nos. 230 and 231 are required to be an OPPD Customer for at least one year to qualify.

OPPD does not pay interest on Level Payment Plan accounts with credit balances. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current month's level payment amount.

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Determination of Billing Non-Demand or Demand

OPPD will utilize information provided by the Customer or obtained from the Customer's usage history or Meter to determine whether a Customer will be billed on a non-Demand or a Demand Rate Schedule. If Demand history is available for Customers moving from a non-Demand Rate Schedule to a Demand Rate Schedule, this Demand history will be used in determining the Customer's Billing Demand for future billing periods. If the Customer provides to OPPD, in writing, information that shows permanent changes in the type of electrical service required, at OPPD's discretion, the Customer may be moved to a non-Demand Rate Schedule for future billings.

Billing Adjustments

OPPD makes reasonable efforts to bill all utility accounts accurately. If errors occur, the error may result in over- or under-billing a Customer's account. Upon discovery of such an error, OPPD will begin the process of either billing the Customer for undercharges or crediting the Customer's account for overcharges, without interest. OPPD will back-bill a Customer or credit a Customer's account for no more than a four~~ (4) ~~year period.

OPPD will not adjust inaccurate Customer billing resulting from mislabeled Meter sockets or cross-wiring to a service within the building's electrical system. At OPPD's discretion, administrative costs associated with mislabeled Meter sockets or cross-wiring to a service may be charged to the Premises Owner.

RATE SCHEDULES

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RATE SCHEDULE NO. 110

Standard Residential Service

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area who meet the criteria to be a Residential Customer as defined in the Service Regulations.

Customers taking Electric Service as single-phase alternating current will be supplied at OPPD's standard voltages of 240 volts or less, for Residential uses, when ~~a~~All-Electric Service furnished under this Schedule is measured by one Meter unless otherwise specified in the Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $30.00 per month

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
0 –- 100 kWh	~~10.48~~10.95 cents/kWh	~~8.63~~9.55 cents/kWh
101 –- 1,000 kWh	~~10.48~~10.95 cents/kWh	~~7.46~~8.85 cents/kWh
1,001+ kWh	~~10.48~~10.95 cents/kWh	~~6.90~~8.74 cents/kWh

A credit of $2.07 per month will be applied to summer monthly kWh consumption of more than 100 kWh and less than 401 kWh.

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $32.07

The minimum monthly bill is calculated as the monthly service charge and the summer energy credit. Any energy usage by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 115

Residential Conservation Service

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area who meet the criteria to be a Residential Customer as defined in the Service Regulations. To qualify for this Rate Schedule, the Customer must meet each of the following:

- Have an electric heat pump in operation that has a Seasonal Energy Efficiency Rating of 14 or higher, with the heat pump installation passing ~~the~~ OPPD's size and efficiency tests, and
- Supply at least 50% of the space-conditioning requirements using the electric heat pump.

Customers taking Electric Service as single-phase alternating current will be supplied at OPPD's standard voltages of 240 volts or less, for Residential uses, when ~~a~~All-Electric Service furnished under this Rate Schedule is measured by one Meter unless otherwise specified in the Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $30.00 per month plus,

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
0 - 100 kWh	~~9.36~~9.61 cents/kWh	~~9.02~~9.50 cents/kWh
101 - 880 kWh	~~9.36~~9.61 cents/kWh	~~7.85~~8.80 cents/kWh
881+ kWh	~~9.36~~9.61 cents/kWh	~~5.68~~7.11 cents/kWh

A credit of $2.07 per month will be applied to summer monthly kWh consumption of more than 100 kWh and less than 401 kWh.

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $32.07

The minimum monthly bill is calculated as the monthly service charge and the summer energy credit. Any energy usage by the Customer during a billing period is charged in addition to the minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Schedule Period

This Rate Schedule will be available for a minimum of five (5) years. Availability beyond five (5) years will continue until the termination of the heat pump program and the last Customer to qualify for this Rate Schedule completes the minimum five (5) year availability.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 226

Irrigation Service

APPLICABILITY

This Rate Schedule is applicable to Owners of farms, or renters with the Owner's guarantee, in rural areas.

Customers taking Electric Service as single-phase ~~(~~or three-phase~~, if available)~~ alternating current will be supplied at OPPD's standard voltages for the operation of pumping equipment and~~, in conjunction with,~~ any crop-drying or grinding equipment for farm purposes. Not applicable to commercial, domestic, or other farm uses, shared or resale service.

OPPD reserves the right to collect from the Customer in advance, part or all of the cost of the additional investment if OPPD's estimated additional investment in lines, transformers, Meter and accessory equipment to serve a pumping location exceeds $75.00 per horsepower of connected Load for single-phase service or $105.00 per horsepower for three-phase service.

BILLING COMPONENTS

Annual Connected Load Charge:

Annual Charge	Single-Phase	Three-Phase
Per horsepower (HP)	$~~21.36~~23.32	$~~27.48~~29.44

Energy Charge:

Energy Usage	Single-Phase	Three-Phase
Per kWh	11.07 cents/kWh	11.07 cents/kWh

~~Energy Charge:~~

~~Energy Usage~~	~~Single-Phase~~	~~Three-Phase~~
~~Per kWh~~	~~11.07 cents/kWh~~	~~11.07 cents/kWh~~

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Annual Connected Load Charge:

$~~213.60~~233.20 for Single-Phase

$~~274.80~~294.40 for Three-Phase

Minimum Annual Connected Load Charge is calculated as the 10 HP minimum ~~a~~Annual ~~c~~Connected Load ~~c~~Charge requirement~~ of $213.60 for single-phase, or $274.80 for three-phase~~.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Billing Procedure

The annual billing period for Rate Schedule No. 226 – Irrigation Service, begins in May and ends the following April. Customers will be billed one-third of the annual connected load charge during May, June, and July of each of the contract years, plus any charges for energy. During the remaining months, the Customer will be billed for the energy used each month. If a Customer starts service before or after May 1st, the prorated connected load charge will be billed in May, June, or July depending on the start date for the Customer. When a Customer discontinues service, the prorated connected load charge will be billed or credited the following month.

ADMINISTRATIVE

Definitions

Connected Load: The total full Load continuous ratings in horsepower, as prescribed by the standards of the National Electrical Manufacturers Association in effect at the time of purchase from the manufacturer of motors and other current-consuming equipment, installed by the Customer.

Equivalent Electrical Load: The electrical power required to operate mechanical Load at the nameplate horsepower. One horsepower will be converted to an equivalent electrical Load using an 85% efficiency. (One horsepower mechanical equals 877 watts electrical.)

Contract Period

Five years, or longer, at OPPD's discretion. Each contract, at the expiration date, will automatically be renewed for an additional one-year period, unless cancelled by written notice by either party at least 60 days before the expiration date.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230

General Service Non-Demand

APPLICABILITY

This Rate Schedule is applicable to all Customers throughout OPPD's Service Area that have monthly Billing Demands less than 50 kilowatts during each of the four (4) Summer billing months, June through September.

Customers taking Electric Service as single-phase ~~(~~or three-phase~~, if available)~~ alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location are measured by one Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 ~~-~~– Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $33.00 per month

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
0 –~~-~~ 1,000 kWh	~~9.81~~10.62 cents/kWh	~~7.89~~8.40 cents/kWh
1,001 –~~-~~ 3,000 kWh	~~9.81~~10.62 cents/kWh	~~7.89~~8.40 cents/kWh
3,001+ kWh	~~9.81~~10.62 cents/kWh	~~5.24~~7.19 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $33.00

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231

General Service ~~-~~ – Small Demand

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that meet or exceed a Billing Demand of 50 kilowatts during one of the four (4) ~~summer~~ Summer billing months, June through September.

Customers taking Electric Service as single-phase ~~(~~or three-phase~~, if available)~~ alternating current will be supplied at OPPD's standard voltages, for all uses, when all Electric Service at one location is measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This Rate Schedule is not available to those Customers taking service under Rate Schedule No. 226 ~~-~~ – Irrigation Service.

BILLING COMPONENTS

Monthly Service Charge: $19.86 per month

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~7.08~~7.89

Minimum Billing Demand of 18 kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
First 300 kWh per kW of demand	7.38 cents/kWh	5.92 cents/kWh
All additional kWh	5.81 cents/kWh	4.56 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $~~147.30~~161.88

The minimum monthly bill is calculated as the 18-kilowatt minimum Demand requirements of $~~127.44~~142.02, plus the monthly service charge of $19.86. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date. For Customers on OPPD's Level Payment Plan, the Late Payment Charge will be calculated as 4% of the current level payment amount.

Determination of Demand
Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 18 kilowatts

ADMINISTRATIVE
Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 232

General Service ~~-~~- Large Demand

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as single-phase ~~(~~or three-phase~~, if available)~~ alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or
resale service.

BILLING COMPONENTS

Monthly Service Charge: $115.31 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~13.35~~14.36

Minimum Billing Demand of 1,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	~~4.49~~4.83 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $~~13,465.31~~14,475.31

The minimum monthly bill is calculated as the 1,000-kilowatt minimum Demand requirements of $~~13,350~~14,360, plus the monthly service charge of $115.31. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between

85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 1,000 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 245

Large Power ~~-~~- Contract

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as three-phase alternating current will be supplied at an OPPD standard voltage above 11,000 volts provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage. Also, all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $465.28 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~15.17~~16.49

Minimum Billing Demand of 10,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	~~3.97~~4.32 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill: $~~152,165.28~~165,365.28

The minimum monthly bill is calculated as the 10,000-kilowatt minimum Demand requirements of $~~151,700~~164,900 plus the monthly service charge of $465.28. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 10,000 kilowatts

ADMINISTRATIVE

Contract Period

A minimum of five (5) years, with automatic renewal for additional five-year periods, unless cancelled by written notice by either party at least one (1) year prior to the expiration date.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 250

Large Power

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as three-phase alternating current will be supplied at an OPPD standard voltage above 11,000 volts provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage. Also, all the Electric Services at one location are measured by one Demand Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

BILLING COMPONENTS

Monthly Service Charge: $511.73 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~15.17~~16.49

Minimum Billing Demand of 20,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	~~3.91~~4.14 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill: $~~303,911.73~~330,311.73

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirements of $~~303,400~~329,800, plus the monthly service charge of $511.73. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 90% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 75% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 20,000 kilowatts

ADMINISTRATIVE

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 261M

Large Power – High-Voltage Transmission Level – Market Energy

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area.

Customers taking Electric Service as three-phase service will be supplied radially from OPPD's system at a nominal standard voltage of 161,000 volts or 345,000 volts, where the Customer owns its electric substation for the delivery of the service.

The minimum Demand for service under this Rate Schedule is 20,000 kilowatts for service at 161,000 volts or a minimum Demand of 200,000 kilowatts for service at 345,000 volts each month.

Customers must substantiate to OPPD's satisfaction that their Demand requirements will meet the minimum Demand requirements of this Rate Schedule within 18 months of establishing service under this Rate Schedule.

The Customer's high voltage Electric Service will be measured by one Demand Meter, unless a Customer takes emergency or special service as required by OPPD's Service Regulations.

BILLING COMPONENTS

Monthly Service Charge: $10,000.00 per month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~18.36~~19.51

Minimum Billing Demand of 20,000 kilowatts per month for interconnection at 161,000 volts~~,~~ or 200,000 kilowatts per month for interconnection at 345,000 volts.

Energy Charge

An Energy Charge will be assessed based on the number of kilowatt-hours consumed in any given hour multiplied by the appropriate cost to purchase energy from the Southwest Power Pool (SPP) for that hour. OPPD will notify the Customer of the SPP node used to price the hourly energy and all applicable SPP charges. The billing notice will be enforceable under this Rate Schedule and OPPD's Service Regulations.

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Minimum Monthly Bill:

$~~377,200~~400,200 for Customers taking service at 161,000 volts

or

~~$3,682,000~~$3,912,000 for Customers taking service at 345,000 volts

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirement of $367,200 for interconnection at 161,000 volts, or 200,000 kilowatt minimum Demand requirement of $3,672,000 for interconnection at 345,000 volts, plus the monthly service charge of $10,000. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Gross Revenue Charge:

The Charges under this rate shall be subject to the 5% Gross Revenue Charge to recover the payment in lieu of taxes as established in Neb, Const. art. VIII, sec. 11 OPPD will submit this payment to the appropriate political subdivision(s) as provided by the law.

Determination of Demand

Demand, for any billing period during the initial 18 months of service, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's greatest use during the same billing period.

For billing periods of 18 months or after the initial service date, Demand will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of Customer's highest use during the same billing period.

If, after month 17 of the initial service date, the Demand is less than 95% leading or lagging of the Customer's highest 15-minute kilovolt ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 95% of the kilovolt ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 90% of the highest 15-minute Power Factor-adjusted Demand during the Summer billing months of the preceding eleven (11) months, or
- 75% of the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 20,000 kilowatts for Customers receiving service at 161,000 volts, or
- 200,000 kilowatts for Customers receiving service at 345,000 volts

~~or~~

~~200,000 kilowatts for Customers receiving service at 345,000 volts~~

ADMINISTRATIVE

Special Conditions

Customers taking service under this Rate Schedule must provide written notice twelve (12) months before switching between the Market Energy Base Option and the Non-Market Energy Base Option.

Customers taking service under this Rate Schedule will be required to execute and comply with operational policies and any other requirements as determined by OPPD.

OPPD assumes no liability for Customer-O~~o~~wned facilities.

OPPD will determine the Point(s) of Delivery using the information provided by the Customer regarding the Customer's requirements. The Point of Delivery will be based on the needs and requirements of OPPD's systems and facilities.

Due to the nature of service provided under this Rate Schedule, OPPD and the Customer will jointly agree upon a metering point that adequately and safely meets OPPD's requirements. If OPPD determines it is necessary to place Meters in a location away from the Point of Delivery, OPPD reserves the right to adjust its Meter readings and billings to account for delivery line losses.

Customers receiving service from more than one high voltage transmission source are restricted from tying or paralleling the sources at any time or for any duration. All transfers between sources must be performed as open transition transfers.

For planning purposes, the Customer will notify OPPD of their expected monthly Demand (in kilowatts) at least one week before the start of each month. In the event the Customer's actual monthly Demand varies by five (5) or more megawatts, OPPD reserves the right to request more frequent notifications regarding expected Loading conditions.

Under OPPD's Service Regulations, the resale, redistribution, marketing or extension of Electric Service received by the Customer, including in any wholesale or other markets, is prohibited. Customers are prohibited from taking wholesale transmission services to serve their Demand.

Customers served under this Rate Schedule shall not export power on OPPD's electrical system.

Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 236

Dusk-to-Dawn Lighting

APPLICABILITY

This Rate Schedule is applicable to all Customers, for private outdoor lighting service, when such lighting facilities are operated as an extension of OPPD's distribution system, except for:

- Installations on public or semi-public thoroughfares including public parks, where such installations would conflict with a legally constituted public authority having jurisdiction, and
- ~~(1)~~ Athletic fields covered by other Rate Schedules.

Customers taking Electric Service as single-phase alternating current, 120 volts, will be supplied by OPPD for the operation of outdoor-type light fixtures using mercury vapor or high-pressure sodium lamps mounted on OPPD-owned wood poles on which overhead secondary conductors exist, or to which such secondary conductors can be extended, except where the extension of such secondary conductors is impractical.

This service will be unmetered, and the light fixtures will operate each night automatically from dusk to dawn. All facilities necessary for service under this Rate Schedule will be installed, owned and maintained by OPPD. This service is for the exclusive use of the Customer for private outdoor lighting as specified and cannot be resold to others.

Availability of the 175-watt and the 400-watt mercury vapor light fixture is restricted to existing units. As existing 175-watt and 400-watt mercury vapor units require maintenance, OPPD will replace them with 100-watt and 200-watt high-pressure sodium units, respectively.

BILLING COMPONENTS

Monthly Rate:

For an installation on an existing wood pole and connected to existing overhead secondary conductors on such pole:

Lamp Size (watts)	Lamp Type	Per Unit Charge
100	7,200 lumen high-pressure sodium light fixture	$~~13.70~~ 14.06
175	7,000 lumen mercury-vapor light fixture*	$~~13.70~~ 15.48
200	22,000 lumen high-pressure sodium light fixture	$18.69
400*	20,000 lumen mercury-vapor light fixture*	$~~18.69~~ 20.52
33	LED	$13.02
108	LED	$17.76

Where an extension of overhead secondary facilities is required, and where such extension is acceptable to OPPD, the monthly rate will be increased by:

Charges as Required	Per Unit Charge
Additional transformer installed*	$~~5.02~~6.68
Additional pole installed	$~~1.38~~1.67
Additional span of secondary conductors installed	$~~0.75~~0.85

**Restricted to existing Customers.*

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

ADMINISTRATIVE

Contract Period

On initial installation of a light at a given location, the term of contract for service under this Rate Schedule will be for a period of two (2) years. After the two (2) year period, the service will continue until the customer contacts OPPD to request to have the light removed.

Special Conditions

Resolution No. 5733 states OPPD's Management has been authorized to add, delete, or restrict lighting rates in Rate Schedule No. 236 – Dusk to Dawn Lighting and Rate Schedule No. 350 – Municipal Service Street Lighting at any time, provided that any changes will be:

- Based on generally accepted cost-of-service ratemaking principles,
- Reviewed by the Board of Directors' rate consultant, and
- Approved by the Board of Directors during the next meeting at which the Board considers any rate action.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 350

Municipal Service Street Lighting

APPLICABILITY

This Rate Schedule is applicable to the State of Nebraska, and all Counties, Cities, Villages and Sanitary Improvement District's throughout OPPD's Service Area. The single-phase alternating current Electric Service will be supplied at OPPD's standard voltages for the operation of street lighting systems for public highways, streets, and thoroughfares.

Units of street lighting not priced in Parts 1 or 2 will be priced explicitly in the street lighting contract.

Each Customer shall enter into a contract with OPPD for street lighting service. Such a contract shall be for a period of one year, or longer, at OPPD's option, and shall include a reference to this street lighting Schedule and the Service Regulations of OPPD.

OPPD, at its discretion, may replace decorative units with like decorative units if the original decorative unit is no longer available or is not available at a reasonable cost.

BILLING COMPONENTS

Billing Procedure: Annual rates will be billed in 12 equal monthly installments.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule. The adjustment will be applied to the monthly energy usage for each lighting method based on the relevant light source and lamp size for such method.

Municipal Service Street Lighting:

Part 1 – OPPD Owned and Maintained System

Category No. 1: Standard Utility Style Lighting Methods Annual Rate: H.P. Sodium Light Source

Overhead Wiring: OPPD-Owned Pole

			Wood Pole		***Metal Pole***	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61*	25	100	$~~168.48~~ 182.04	N/A	$~~214.18~~ 231.36	$~~260.37~~ 281.28
65**	40	400	$~~321.42~~ 347.16	N/A	$~~386.65~~ 417.60	N/A
66*	30	200	$~~212.87~~ 229.92	N/A	$~~262.36~~ 283.32	$~~342.08~~ 369.60
67*	40	200	$~~237.98~~ 257.04	N/A	$~~299.76~~ 323.76	N/A
68**	30	400	$~~289.94~~ 313.20	N/A	$~~364.57~~ 393.84	N/A

*Restricted

Underground Wiring: OPPD-Owned Pole

			Wood Pole		***Metal Pole***	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61*	25	100	$~~177.90~~ 192.12	N/A	$~~224.47~~ 242.52	$~~270.67~~ 292.44
65**	40	400	$~~346.89~~ 374.76	N/A	$~~404.50~~ 436.92	$~~580.02~~ 626.52
66*	30	200	$~~229.76~~ 248.28	N/A	$~~277.37~~ 299.52	$~~355.58~~ 384.12
67*	40	200	$~~276.76~~ 298.92	N/A	$~~334.06~~ 360.84	$~~403.20~~ 435.48
68**	30	400	N/A	N/A	$~~378.08~~ 408.48	$~~519.74~~ 561.36

*Restricted

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
61*	25	100	$~~142.37~~ 153.72	$~~256.34~~ 276.84
66*	30	200	$~~180.43~~	$~~300.64~~

			195.00	324.72

*Restricted

Category No. 2: Standard Decorative Lighting Methods Annual Rate

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Twin Lamps
51	30	200	H.P. Sodium	$~~412.27~~ 445.32	-$~~540.45~~ 583.80
52	25	100	H.P. Sodium	$~~370.88~~ 382.80	-$~~448.78~~ 484.80
53	30	400	H.P. Sodium	-$~~510.21~~ 551.16	-$~~784.59~~ 847.44
57	30	400	Metal Halide	$~~513.83~~ 555.00	N/A
58	40	400	H.P. Sodium	-$~~526.45~~ 568.56	-$~~873.38~~ 943.32
59	40	400	Metal Halide	-$~~558.81~~ 603.60	-$~~725.47~~ 783.60

Category No. 3: Restricted Lighting Methods Annual Rate

Overhead Wiring: OPPD-Owned Pole

				Wood Pole	*Metal Pole*	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Single Lamp	Twin Lamps

14	30	400	Mercury Vapor	$~~253.58~~ 273.96	$~~298.46~~ 322.32	$~~506.53~~ 547.08
15	25	175	Mercury Vapor	$~~165.34~~ 178.68	$~~201.62~~ 217.80	N/A
16	25	100	Mercury Vapor	$~~137.24~~ 148.32	$~~173.52~~ 187.44	N/A
17	25	250	Mercury Vapor	$~~190.41~~ 205.68	$~~226.69~~ 244.92	N/A
44	40	400	Mercury Vapor	$~~277.06~~ 299.28	$~~342.29~~ 369.72	N/A
48	40	700	Mercury Vapor	$~~382.95~~ 413.64	N/A	N/A
49	40	1,000	Mercury Vapor	$~~486.13~~ 525.12	$~~551.36~~ 595.56	N/A
63	30	250	H.P. Sodium	$~~206.35~~ 222.96	$~~280.99~~ 303.60	N/A

Underground Wiring: OPPD-Owned Pole

				Wood Pole	*Metal Pole*	
Method	Approx. Mounting Height (feet)	*Lamp Size* (watts)	Light Source	Single Lamp	Single Lamp	Twin Lamps
14	30	400	Mercury Vapor	$~~268.38~~ 289.80	$~~311.98~~ 336.96	$~~519.27~~ 560.88
15	25	175	Mercury Vapor	$~~184.93~~ 199.80	$~~211.92~~ 228.96	$~~312.19~~ 337.32
16	25	100	Mercury Vapor	N/A	$~~183.81~~ 198.60	N/A
17	25	250	Mercury Vapor	$~~210.00~~ 226.80	$~~236.98~~ 255.96	$~~380.88~~ 411.36
44	40	400	Mercury Vapor	N/A	$~~359.82~~ 388.56	N/A
49	40	1,000	Mercury Vapor	N/A	$~~531.26~~ 573.84	N/A
62	30	400	H.P. Sodium	N/A	N/A	$~~593.65~~ 641.16
63	30	250	H.P. Sodium	$~~229.15~~ 247.56	$~~294.50~~ 318.12	N/A
64	40	250	H.P. Sodium	N/A	$~~320.60~~ 346.32	N/A

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Single Lamp	Twin Lamps
14	30	400	Mercury Vapor	-$~~253.65~~ 274.08	N/A
15	25	175	Mercury Vapor	-$~~150.76~~ 162.84	N/A

Category No. 4: Optional Decorative Lighting Methods Annual Rate

Decorative Method without Base: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90*	A	16	70	H.P. Sodium	Acorn	-$~~284.55~~ 307.32
90	E	12	39	LED	Acorn	$~~348.64~~ 376.56
90	H	16	39	LED	Acorn	$~~346.62~~ 374.52
91*	A	16	70	H.P. Sodium	Globe	-$~~444.15~~ 479.76
91*	E	16	39	LED	Globe	$513.53
93*	A	20	100	H.P. Sodium	Lantern	-$~~246.87~~ 266.64
93*	E	20	51	LED	Lantern	$~~266.08~~ 287.40

*Restricted

Decorative Method Base and Ring: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90*	C	16	70	H.P. Sodium	Acorn	-$~~303.63~~ 327.96
90	F	12	39	LED	Acorn	$~~379.31~~ 407.40
90	I	16	39	LED	Acorn	$~~377.29~~ 407.52
91*	C	16	70	H.P. Sodium	Globe	-$~~463.22~~ 500.28
91*	F	16	39	LED	Globe	$544.20
92*	C	20	100	H.P. Sodium	Top Hat	-$~~258.69~~ 279.48

*Restricted

Decorative Method Base and Ring and Outlet: OPPD-Owned Pole

Method	Option	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
90	G	12	39	LED	Acorn	~~-~~$~~488.68~~ 498.84
90	J	16	39	LED	Acorn	~~-~~$~~458.69~~ 481.80

Decorative Method Pay Up Front: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Light Source	Fixture	Single Lamp
07L	12 or 16	51	LED	Top Hat or Lantern	$~~208.75~~ 217.56
08L	12 or 16	39	LED	Acorn or Globe	$~~206.20~~ 211.44
09	14	66	LED	Bounce	~~-~~$~~211.70~~ 225.12
12*	12	70	H.P. Sodium	Acorn	~~-~~$~~206.57~~ 223.08
13*	16	70	H.P. Sodium	Twin Acorn	$~~292.29~~ 315.72
13L*	16	39	LED	Twin LED Acorn	$~~256.07~~ 276.60
94*	16	70	H.P. Sodium	Acorn	~~-~~$~~206.57~~ 223.08
95*	16	70	H.P. Sodium	Globe	~~-~~$~~216.38~~ 233.76

96*	20	100	H.P. Sodium	Top Hat	-$~~224.47~~ 242.52
97*	20	100	H.P. Sodium	Lantern	-$~~224.47~~ 242.52
98*	14	150	Metal Halide	Bounce	-$~~214.02~~ 231.24

*Restricted

Category No. 5: LED Lighting Methods Annual Rate

Overhead Wiring: OPPD-Owned Pole

			Wood Pole		***Metal Pole***	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
61L	25	54	-$~~107.81~~ 116.76	-$~~165.48~~ 178.80	-$~~150.28~~ 162.84	-$~~208.13~~ 224.76
65L	40	207	-$~~234.73~~ 253.56	N/A	-$~~279.99~~ 302.40	N/A
66L	30	108	-$~~135.10~~ 146.04	-$~~222.59~~ 240.48	-$~~195.45~~ 211.20	-$~~249.48~~ 269.52
67L	40	108	-$~~153.06~~ 165.48	N/A	-$~~198.96~~ 214.92	N/A
68L	30	207	-$~~230.86~~ 249.36	N/A	$~~275.52~~ 297.60	N/A

Underground Wiring: OPPD-Owned Pole

			Wood Pole		***Metal Pole***	
Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps	Single Lamp	Twin Lamps
51L	30	89	N/A	N/A	-$~~324.50~~ 350.52	-$~~448.46~~ 484.32
52L	25	46	N/A	N/A	-$~~298.40~~ 322.32	-$~~407.33~~ 439.92
53L	30	89	N/A	N/A	-$~~383.65~~	-$~~636.79~~

					414.36	666.84
58L	40	232	N/A	N/A	-$~~390.70~~ 422.04	$~~687.18~~ 722.52
61L	25	54	-$~~127.54~~ 137.76	-$~~185.39~~ 200.28	-$~~173.91~~ 188.40	-$~~222.71~~ 240.60
65L	40	207	-$~~266.25~~ 287.64	N/A	-$~~311.50~~ 336.48	-$~~470.75~~ 508.44
66L	30	108	-$~~161.56~~ 174.48	-$~~236.62~~ 255.60	-$~~225.67~~ 243.84	-$~~263.51~~ 284.64
67L	40	108	-$~~196.16~~ 211.92	-$~~292.74~~ 316.32	-$~~236.94~~ 255.84	-$~~333.52~~ 360.24
68L	30	207	N/A	N/A	$~~305.37~~ 329.88	$~~456.18~~ 492.84

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
51L	30	89	-$~~206.87~~ 223.44	N/A
53L	30	89	-$~~259.49~~ 280.20	N/A
58L	40	232	-$~~260.66~~ 281.52	N/A
61L	25	54	-$~~106.98~~ 115.68	N/A
65L	40	207	-$~~226.98~~ 245.16	-$~~386.22~~ 417.12
66L	30	108	-$~~132.47~~ 143.16	-$~~219.96~~ 237.60
67L	40	108	-$~~160.73~~ 173.64	-$~~257.30~~ 277.92
68L	30	207	-$~~227.30~~ 245.52	N/A

Category No. 5: LED Lighting Methods Annual Rate with Additional Agreements Required

Overhead Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Wood Pole	Metal Pole
29	30	100	-$~~92.81~~ 100.20	N/A
30	30	200	-$~~107.63~~ 116.28	N/A
31	40	200	-$~~131.90~~ 142.44	N/A

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Wood Pole	Metal Pole
28	25	100	~~-~~$~~93.24~~ 100.80	~~-~~$~~143.41~~ 154.92
30	30	200	N/A	$~~192.86~~ 198.96
31	40	200	N/A	~~-~~$~~218.52~~ 236.04

Part 2 – Customer-Owned System Operated by OPPD Annual Method

Method	Lamp Size (watts)	Light Source	Dusk to Dawn
20	100	Mercury Vapor	~~-~~$~~68.87~~ 74.40
22	250	Mercury Vapor	~~-~~$~~113.29~~ 122.40
23	400	Mercury Vapor	~~-~~$~~164.98~~ 178.20
23L	207	LED	~~-~~$~~88.85~~ 96.00
24	700	Mercury Vapor	~~-~~$~~263.95~~ 285.12
25	1,000	Mercury Vapor	~~-~~$~~360.11~~ 389.04
25L	529	LED	~~-~~$~~177.76~~ 192.00
27	150	Incandescent	~~-~~$~~73.86~~ 79.80
40	54	LED	~~-~~$~~48.64~~

			52.56
41	86	LED	$~~69.25~~ 74.88
42	48	LED	~~-~~$~~44.82~~ 48.36
43	168	LED	~~-~~$~~81.15~~ 87.72
71	100	H.P. Sodium	~~-~~$~~73.46~~ 79.32
71L	58	LED	~~-~~$~~52.90~~ 57.24
72	150	H.P. Sodium	~~-~~$~~89.66~~ 96.84
73	250	H.P. Sodium	~~-~~$~~118.50~~ 128.16
74	400	H.P. Sodium	~~-~~$~~171.49~~ 185.28
74L	207	LED	~~-~~$~~88.85~~ 96.00
76	200	H.P. Sodium	~~-~~$~~102.32~~ 110.64
76T	200	Twin H.P. Sodium	$~~176.38~~ 190.56
76L	108	LED	~~-~~$~~63.09~~ 68.28
76LT	108	Twin LED	$~~91.34~~ 98.64
77	50	H.P. Sodium	~~-~~$~~51.55~~ 55.80
77L	25	LED	~~-~~$~~45.52~~ 49.20
78	70	H.P. Sodium	~~-~~$~~57.63~~ 62.28
79	1,000	H.P. Sodium	~~-~~$~~368.53~~ 398.04
80	100	Metal Halide	~~-~~$~~66.72~~ 72.12
80L	65	LED	~~-~~$~~54.46~~ 58.92
81	175	Metal Halide	~~-~~$~~89.56~~ 96.72
81L	48	LED	~~-~~$~~50.66~~ 54.72
81LT	48	Twin LED	$~~61.40~~ 66.36
82	250	Metal Halide	~~-~~$~~113.77~~ 122.88

82L	100	LED	-$~~62.29~~ 67.32
83	400	Metal Halide	-$~~159.42~~ 172.20
87	50	Metal Halide	-$~~50.55~~ 54.60

OPPD has the option of furnishing maintenance service to Part 2 streetlights on a reimbursable basis. The terms and conditions of such service will be set forth in individual contracts.

Part 3 –~~-~~ Rate for Customer's providing poles to OPPD for 5G pole attachments.

Method	Lamp Size (watts)	Light Source	Dusk to Dawn
75	100	Metal Halide	-$~~67.43~~ 72.84
75L	54	LED	-$~~49.22~~ 53.16
75LT	108	Twin LED	-$~~63.46~~ 68.64

ADMINISTRATIVE

Definitions

Method: Identifies the specific combination of features (light source, mounting height, lamp size, and the number of lamps) that comprise an individual streetlight.

Customer-Owned Poles and Fixtures: Poles and fixtures, provided by the Customer, to which OPPD adds OPPD-owned streetlight equipment and separate service wiring.

Units: One or more components, including the fixture, lamp, photocell, and pole, ~~that~~ which comprise a streetlight.

Special Conditions

Resolution No. 5733 states OPPD's Management has been authorized to add, delete, or restrict lighting rates in Rate Schedule No. 236 – Dusk to Dawn Lighting and Rate Schedule No. 350 – Municipal Service Street Lighting at any time, provided that any changes will be:

- Based on generally accepted cost-of-service ratemaking principles,
- Reviewed by the Board of Directors' rate consultant, and
- Approved by the Board of Directors during the next meeting at which the Board considers

any rate action.

Service Regulations
Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 351

Municipal Services Traffic Signals and Signs

APPLICABILITY

This Rate Schedule is applicable to all governmental agencies throughout OPPD's Service Area where service for such purpose is reasonably available, and the use of service can reasonably be controlled and calculated without metering.

Governmental agencies taking Electric Service as single-phase alternating current will be supplied at OPPD's standard voltages for the operation of Traffic Signals, Signs, Flashers, Counters or other devices used in the general control of thoroughfare traffic.

BILLING COMPONENTS

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	~~8.88~~9.63 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: $3.01 per location.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Energy

When service at a location is used continuously, day and night, the average watts in use will be multiplied by 730 hours and divided by 1000.

When service at a location is not used during daylight hours and is disconnected by a control device during such hours, the average watts in use from dusk to dawn will be multiplied by 360 hours and divided by 1000.

Gaseous tube lighting or other low Power Factor devices will be corrected to not less than 90 percent Power Factor.

ADMINISTRATIVE

Special Conditions

Customers taking service under this Rate Schedule agree to:

- Furnish OPPD all information necessary to calculate the monthly kilowatt-hour use
- Notify OPPD immediately of any permanent change in their Load that will affect the kilowatt-hours used
- Cooperate with OPPD to periodically verify Load

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 357

Municipal Service

APPLICABILITY

This Rate Schedule is applicable to all Municipal Utilities throughout OPPD's Service Area.

Municipalities taking Electric Service as three-phase alternating current will be supplied by OPPD at a voltage not less than 2400 volts for use through a ~~municipally owned~~municipally owned and maintained distribution system.

BILLING COMPONENTS

Monthly Service Charge: $143.90 per month

plus, Demand Charge:

Billing Demand	Per kW Month
Per kW	$12.03

Energy Charge:

Energy Usage	Three-Phase
Per kWh	~~4.15~~4.71 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Minimum Monthly Bill: The minimum monthly bill will be the monthly service charge plus the charge for the currently effective Demand.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's kilowatt-hour Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor adjusted-Demand during the Summer billing months of the preceding eleven (11) months, or
- 60% of the highest 15-minute Power Factor adjusted-Demand during the Non-Summer billing months of the preceding eleven (11) months.

ADMINISTRATIVE

Special Conditions

Special Conditions will be included in the contract and will be mutually agreed upon by both parties. This Rate Schedule will be included as part of the contract.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 230M

General Service Non-Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that have monthly Billing Demands less than 50 kilowatts during each of the four (4) ~~s~~Summer billing months.

Customers taking Electric Service as single-phase ~~(~~or three-phase~~, if available)~~ alternating current will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location is measured by one Meter, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This rate is not available to those Customers taking service under Rate Schedule No. 226 –~~-~~ Irrigation Service.

The charges as determined under Rate Schedule No. 230 – General Service – Non-Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $33.00 per month plus,

Energy Charge:

Energy Usage	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
0 – 1,000 kWh	~~9.81~~10.62 ~~₵~~cents/kWh	~~7.89~~8.40 ~~₵~~cents/kWh
1,001~~-~~ – 3,000 kWh	~~9.81~~10.62 ~~₵~~cents/kWh	~~7.89~~8.40 ~~₵~~cents/kWh
3,001+ kWh	10.62~~9.81~~ ~~₵~~cents/kWh	~~5.24~~7.19 ~~₵~~cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 230 – ~~-~~General Service Non-Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 230 – General Service~~-~~ Non Demand.

The minimum Monthly Bill: $33.00

The minimum monthly bill is the monthly service charge. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

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RATE SCHEDULE NO. 231M

General Service – Demand – Offutt Housing Adjustment Rider

APPLICABILITY

This Rate Schedule is applicable to all non-Residential Customers within the designated privatized housing areas at Offutt Air Force Base (Offutt AFB) that meet or exceed a Billing Demand of 50 kilowatts during one of the four (4) S~~s~~ummer billing months, June through September.

Customers taking Electric Service as single-phase (or three-phase, if available) alternating current, will be supplied at OPPD's standard voltages, for all uses, when all the Electric Services at one location is measured by one Meter with a Demand register, unless the Customer takes emergency or special service as required by OPPD's Service Regulations. Not applicable to shared or resale service.

This rate is not available to those Customers taking service under Rate Schedule No. 226 –~~-~~ Irrigation Service.

The charges as determined under Rate Schedule No. 231 – General Service – Demand will apply to this Rate Schedule.

BILLING COMPONENTS

Monthly Service Charge: $19.86 per ~~m~~month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~7.08~~ ~~8.01~~7.89

Minimum Billing Demand of 18 kW per month.

Energy Charge:

Energy Usage	Summer (June 1 – Sept.30)	Non-Summer (Oct. 1 – May 31)
First 300 kWh per kW of demand	7.38 cents/kWh	5.92 cents/kWh
All additional kWh	5.81 cents/kWh	4.56 cents/kWh

Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.
~~Rider Schedule No. 461 – Fuel and Purchased Power Adjustment applies to this Rate Schedule.~~

Offutt Adjustment

A credit adjustment will be applied per kilowatt-hour to all energy billed during the current billing period. The adjustment will be capped so that Customers will not have a rate higher than Rate Schedule No. 231 – ~~-~~General Service ~~-~~– Small Demand. The adjustment will be based on the production cost differential determined by OPPD as follows:

OPPD Cost of Production less WAPA Cost of Production, determined on a cents per kWh basis, applicable to Rate Schedule No. 231 – General Service – ~~-~~Small Demand.

Minimum Monthly Bill: $~~147.30~~161.88

The minimum monthly bill is calculated as the 18-kilowatt minimum Demand requirements of $~~127.44~~142.02, plus the monthly service charge of $19.86. Any energy used by the Customer during a billing period is charged in addition to a minimum bill.

Late Payment Charge:

A Late Payment Charge in the amount of 4% of the Billing Components and applicable taxes will be assessed if the current month's bill payment is not received by OPPD on or before the due date.

Determination of Demand

Demand, for any billing period, will be the kilowatts computed from the readings of OPPD's Meter for the 15-minute interval of the Customer's highest use during the same billing period.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt-ampere Demand, the kilowatt Demand will be increased under this Schedule by 50% of the difference between 85% of the kilovolt-ampere Demand and the Demand as determined above.

The Customer's Demand must be equal to or greater than the larger of the following:

- 85% of the highest 15-minute Power Factor-adjusted Demand during the summer billing months of the preceding eleven (11) months, or
- 60% for the highest 15-minute Power Factor-adjusted Demand during the Non-Summer billing months of the preceding eleven (11) months, or
- 18 kilowatts

ADMINISTRATIVE

Definitions

OPPD's Cost of Production: Costs related to the capacity and amount of electricity produced at each of OPPD's generating plants, purchased power for use by OPPD's Customers, and credits for interchange sales through OPPD's system.

Western Area Power Authority (WAPA) Cost of Production: Actual cost of generation provided by WAPA and assigned to OPPD for delivery to Offutt AFB.

Service Regulations

Customers under this Rate Schedule must comply with all OPPD Service Regulations.

RIDER SCHEDULES

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RIDER SCHEDULE NO. 355

Electric Energy Purchased from Cogenerating and Small Power Producing Facilities

APPLICABILITY

This Rider Schedule is applicable to all Customers who have qualified cogenerating or Small Power Producing Facilities that have the appropriate metering to measure the delivery of electric energy to OPPD.

BILLING COMPONENTS

For facilities with less than 1000 kW of generating capacity:

Service Charge: $4.00 per Meter per month

Energy Credit:
OPPD will pay the Customer based on the type of metering installed as follows:

No Meter: No Rate

	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
All Hours	4.00 cents/kWh	3.52 cents/kWh

Time of Day	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
On-Peak Hours: 6:00A~~.~~M~~.~~ – ~~-~~10:00P~~.~~M~~.~~ M – ~~-~~F	5.40 cents/kWh	4.39 cents/kWh
Off-Peak Hours: All Other Hours	2.73 cents/kWh	2.73 cents/kWh

For facilities with 1000 kilowatts or more of generating capacity, the rate will be based on OPPD's avoided costs and will be established for each facility.

ADMINISTRATIVE

Special Conditions

A written agreement between the Customer and OPPD is required. OPPD will not operate in parallel without a contract.

The Customer will pay for the additional equipment required for parallel operation and installation costs, as outlined in the agreement, before the initiation of parallel operation.

The interconnection of this equipment with OPPD's system must meet the standards specified in the OPPD policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 461

Fuel and Purchased Power Adjustment

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area that take electrical service under OPPD's Rate Schedule Nos. 110, 115, 226, 230, 231, 232, 236, 245, 250, 350, 351, or 357.

This Schedule applies an adjustment per kilowatt-hour to all retail and municipal service energy sales to reflect changes in fuel and purchased power expenses that are above, or below, the Fuel and Purchased Power Base Rate.

BILLING COMPONENTS

FPPA Charge:

The Customer's monthly bill will reflect a Fuel and Purchased Power Adjustment (FPPA) applied to the monthly kilowatt-hour usage.

FPPA Annual Calculation

The FPPA is calculated as follows:

$$FPPA = \frac{NEC - O}{S} - F$$

Where:

NEC = Annual Budgeted Net Energy Costs = (FC +C +PP –OSSR)

- FC = Fuel Costs: These are the costs incurred to support the generation of electricity
- C = Consumables: Materials that are used or depleted as part of the generating process and vary with each kilowatt-hour produced
- PP = Purchased Power Costs: Costs from Southwest Power Pool transactions associated with purchase of power
- OSSR = Off-System Sales Revenue: Revenues from Southwest Power Pool transactions associated with off-system sales

O = Over/Under Balance: For any given period, the Over/Under variance is the difference between the actual net energy costs and the revenue generated by the FPPA Base Rate plus the FPPA in effect during the period

S = Actual Budgeted Energy Sales: Budgeted kilowatt-hour sales to retail and municipal service customers

F = Fuel and Purchase Power Base Rate: The portion of the energy charge component of the applicable OPPD Rate Schedules that recovers the net costs of fuel, purchased power, off-system sales and related consumable costs. For all applicable Rate Schedules, the Fuel and Purchased Power Base Rate is 1.951 cents per kilowatt-hour

OPPD will adjust the FPPA annually on January 1st of each year and will calculate the FPPA before that date. To facilitate that calculation, OPPD will establish its fuel and purchased power budget for the year in advance of January 1st of that year. The Over/Under Balance to be included in the FPPA will be the amount approximately three (3) months before January 1 of the upcoming year, plus the projected amounts for the remainder of the calendar year. The amount will be transferred from the Over/Under Balance to the FPPA. Accordingly, the Over/Under Balance will be adjusted by the amount to be included in the FPPA.

ADMINISTRATIVE

Special Conditions
OPPD reserves the right to modify the FPPA at any time, with approval of the Board of Directors.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 462

Primary Service Discount

APPLICABILITY

This Rider Schedule is applicable to Customers taking single-phase or three-phase service from OPPD at a standard available voltage above 11,000 volts, provided there is only one transformation involved from an OPPD transmission voltage (above 60,000 volts) to the service voltage.

This Rider Schedule is not available to those Customers taking service under Rate Schedule Nos. 245, 250, ~~and~~ or 261M.

BILLING COMPONENT

The monthly credit will be calculated as a percent of the monthly bill as determined by the applicable Rate Schedule:

Delivery Voltage	Discount
4,000 to 60,000	3%
60,001+	5%

ADMINISTRATIVE

Special Conditions

OPPD may change its standard delivery voltage to any affected Customer receiving a discount after advanced written notice. The Customer has the option to change their system to receive service at the new standard delivery voltage or to accept service without the Primary Service Discount after the change in delivery voltage through transformers owned by OPPD.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 464

Standby Service

APPLICABILITY

This Rider Schedule is applicable to all Customers normally serving all or a portion of their own electrical or mechanical Load from Customer-O~~o~~wned equipment when the sum of the combined nameplate rating of the primary generator(s) and the combined nameplate rating of the mechanical Load converted to Equivalent Electrical Load in excess of 25 kW. (The primary generator(s) and the Equivalent Electrical Load shall be referred to as "Units.")

This Rider Schedule does not apply to Units operated for emergency purposes, to Emergency Generating Unit(s), Auxiliary Generating Unit(s) operated as standby to the Customer's Units, or for Load not requiring Standby Service (Load is permanently isolated from OPPD's System), for shared service, or as leased capacity to OPPD under Rate Schedule No. 467L. This Rider Schedule is not mandatory for Customer-O~~o~~wned renewable energy equipment.

BILLING COMPONENTS

Standby Service Option No. 1 –~~–~~ Standby Service for the Customer's Units
Standby Service Option No. 2 ~~–~~– Standby Service with separate status (on/off) metering of the primary, auxiliary, and mechanical generating unit(s):

Monthly Service Charge:

Standby Service Option	Monthly Rate
Standby Option 1:	No Rate
Standby Option 2:	$45.45

Standby Charge:

Electric Service Level	*Standby Option 1*:	*Standby Option 2*:
Primary Level	$5.08/kW of Contract Demand	$5.08/kW of Contract Demand
Secondary Level	$5.55/kW of Contract Demand	$5.55/kW of Contract Demand

Rider Schedule No. 462 – Primary Service Discount does not apply to this Rider Schedule.

Determination of Contract Demand (Applies to Options 1 and 2)
Where OPPD is required to stand ready to supply Standby Service, the Contract Demand shall be equal to:

(1) the Load normally isolated from OPPD's System by a throw-over switch and normally served by the Customer's equipment, and/or

(2) the nameplate rating of the Customer's Primary Generating Unit(s) normally operated in parallel with OPPD's System if the nameplate rating of the Primary Generating Unit(s) is less than the maximum 15-minute peak Demand of the Customer's facility, or

(3) the maximum 15-minute peak Demand of the Customer's facility if the nameplate rating of the Primary Generating Unit(s) normally operated in parallel with OPPD's system is greater than the maximum 15-minute peak Demand of the Customer's facility, whichever is applicable.

The Customer may arrange for OPPD to supply Standby Service for a portion of the Load normally isolated from OPPD's System with a throw-over switch and normally served by the Customer's equipment. The Customer will furnish and install suitable switchgear to reduce Demand to the Contract Demand level when the Customer's Demand exceeds the Contract Demand during an outage of the Customer's equipment. The switchgear furnished by the Customer shall be approved by OPPD and will be under exclusive OPPD control.

Demand and Energy Charges (Applies to Options 1 and 2)

The charges, as determined under the regular Rate Schedule, apply to the service rendered.

However, if an increase in Billing Demand occurs in the current billing period as a result of a total outage of one or more of the Customer's primary or mechanical generating unit(s) and the failure of the auxiliary unit(s) to operate as back-up to the primary unit(s) or the Equivalent Electrical Load, the current month's Standby Charge will be reduced. The reduction will be based on the difference between the Billing Demand, as determined from the highest actual Meter reading occurring during such outage interval, and the Billing Demand, as determined from the Reference Demand.

The Reference Demand is the highest Demand resulting from any 15-minute Meter reading occurring during the current billing period being reduced by any portion of the Customer's Contract Demand not served by the Customer's equipment during such 15- minute period. The resulting Reference Demand will not be established higher than the original 15-minute Meter reading.

If, in the current billing period, the actual metered Demand during such outage interval is greater than the maximum metered Demand during any non-outage period, the Reference Demand will be used in the determination of charges for the next 11 months.

Standby Service Option No. 3 –– Waiver of Standby Charge by designation of a Firm Demand:

Standby Charge:

Electric Service Level	Standby Option 3:
Excess Demand Charge	Applies

Rate Schedule No. 462 – Primary Service Discount does not apply to this Rate Schedule.

Demand and Energy Charges (Applies to Option 3)

The charges as determined under the regular Rate Schedule applicable to the service rendered with the exception that the Demand used to calculate the monthly bill will be determined as outlined in the "Determination of Billing Demand" clause within this Rate Schedule.

Excess Demand Charge (Applies to Option 3)

The current levelized cost of a combustion turbine peaking unit, including fixed capital and operation and maintenance cost. This charge will be increased by 23% to recover costs associated with the reserve margin and Demand losses on the transmission and distribution system. The resultant charge will be applied to the Customer's Excess Demand.

Designation of Demand (Applies to Option 3)

The Customer must (1) designate a Firm Demand for the facility to be served under this Rate Schedule and (2) declare the nameplate rating of the Customer's Units.

If the maximum potential Demand of a Customer's facility exceeds the supply capability of OPPD's electrical network at that location, the Customer will furnish and install suitable switchgear to limit Demand to a level determined by OPPD. This level will be no less than the Firm Demand level.

Determination of Billing Demand (Applies to Option 3)

The Customer's monthly Billing Demand will be determined by (a) the Power Factor-adjusted Demand, as calculated in the "Determination of Demand" clause in the applicable Rate Schedule subject to Demand minimums, or (b) the Firm Demand, whichever is greater.

Determination of Excess Demand Charges (Applies to Option 3)

If the Customer's Power Factor adjusted Demand exceeds the Firm Demand during the On-Peak Periods of any calendar year, the Customer will be assessed the Excess Demand Charge for the difference between the Firm Demand and the Power Factor adjusted Demand in the current month. The Excess Demand Charge will be assessed only once for each kW for which the Power Factor ~~a~~Adjusted-Demand exceeds the Firm Demand during the On-Peak Periods in any calendar year.

Minimum Monthly Bill

The minimum monthly bill from the regular Rate Schedule, applicable to the service rendered, plus the charges for the applicable Standby Service Option.

ADMINISTRATIVE

Schedule Duration:

A minimum of three years, pursuant to a written agreement. Said agreements, at their expiration dates, will automatically be renewed for additional two-year periods unless cancelled by written notice by either party at least six months before the expiration dates.

Customers may elect to take service under a different Standby Service Option only after the current option has been in effect for at least 12 months. The Customer will provide written notice to OPPD of their intention to change options sixty (60) days before the proposed effective date of such change.

For those Customers whose Contract Demand is determined according to Condition No. 1 or Condition No. 3 in the "Determination of Contract Demand" clause within this Rate Schedule, the level of the Contract Demand will be reviewed annually.

For Standby Service Option No. 3, the Firm Demand may be decreased only after the current Firm Demand has been in place for at least 12 months. The Customer will provide written notice to OPPD of their intention to decrease the Firm Demand 30 days before the proposed effective date of such decrease.

The Firm Demand may be increased according to the following conditions:

1. For increases in the Firm Demand that are greater than 20 MW, the Customer will provide written notice to OPPD of their intention to increase the Firm Demand at least six months before the proposed effective date of the increase.

2. For increases in the Firm Demand that are less than or equal to 20 MW, the Customer will provide written notice to OPPD of their intention to increase the Firm Demand at least three months before the proposed effective date of the increase.

Definitions

Contract Demand: The nameplate capacity of the Customer's Primary Generating Unit(s) or the Equivalent Electrical Load normally isolated from OPPD's System and served by a Customer's generating equipment.

Equivalent Electrical Load: The electrical power required to operate mechanical Load at the nameplate horsepower. One horsepower will be converted to Equivalent Electrical Load using an 85% efficiency. (One horsepower mechanical equals 877 watts electrical.)

On-Peak Periods: Monday through Friday between the hours of 12:00 P.M. ~~Noon~~ and 10:00 P.M. during the months of June, July, August, and from September 1 through September 15, excluding Federal Holidays.

Firm Demand: The Demand to be served by OPPD that the Customer expects to be served by OPPD in normal operation during the On-Peak Periods.

Excess Demand: The amount of the Customer's Demand served by OPPD that exceeds the Firm Demand during the On-Peak Periods.

Special Conditions

OPPD will not be required to furnish more than one Standby Service Option for a Customer taking service at one location.

OPPD will not be required to furnish duplicate service hereunder.

The Customer shall reimburse OPPD for all metering and switchgear equipment and the maintenance of such equipment necessary to administer this Rate Schedule.

Any metering and switchgear equipment installed, for purposes of this Rate Schedule, on the Customer's side of the Meter by the Customer must be approved by OPPD and must be installed and maintained to provide a safe environment for OPPD's and Customer's personnel.

Any metering and switchgear located on the Customer's side of the Meter must be inspected by OPPD and tested before being energized and tested once a year after that with the results of the tests reviewed and approved by OPPD.

All installations must be in conformance with the National Electrical Safety Code.

OPPD will not be liable for any damage to a Customer's equipment due to the failure of any metering or switchgear installed by the Customer on the Customer's side of the Meter.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467 & 467H

General Service/Large General Service – Curtailable
(Currently Unavailable for New Customers)

APPLICABILITY

This Rider Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that are capable and willing to curtail a minimum of 100 kilowatts of Curtailable Demand (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions) during Curtailment Periods specified by OPPD, subject to the terms of this Rider Schedule and any applicable Curtailment Agreement.

The Customer must agree to reduce the Load served by OPPD during a Curtailment Period, upon request by OPPD, to the Firm Demand. The Customer must enter into a Curtailment Agreement with OPPD, and the decision to enter into a Curtailment Agreement with any Customer under this Rider Schedule is at the discretion of OPPD and is based on operational and market conditions.

This Rider Schedule is not available to those Customer accounts served under Rider Schedule Nos. 355, 464, ~~355,~~ or 467L.

BILLING COMPONENTS

Monthly Service Charge: $84.70 per month

Curtailment Credit:

Option	467	467H
Minimum Demand	100 kW – 9,999 kW	10,000+ kW
Capacity Curtailment Only (Max. 100 hours per year)	$4.67 per kW	$4.96 per kW

Determination of Firm Demand and Curtailable Demand

For purposes of determining the Firm Demand and Curtailable Demand, before December 1 of each year, OPPD will review the Customer's recent historical Load at the time of OPPD's system peak to determine the Customer's average Load for those hours in which OPPD's Load was within 90% of OPPD's annual system peak. Periods during which the Customer provided a Demand reduction in response to a curtailment request will be excluded from this calculation.

Prior to January 1, the Customer may elect to adjust the Firm Demand amount provided the resulting Curtailable Demand is at least 100 kilowatts (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions).

An adjustment will be made to the Curtailable Demand if the annual review of the Customer's historical Load characteristics indicates a smaller amount of Curtailable Load is appropriate. If the annual review indicates that the Customer is unable to provide a minimum of 100 kilowatts of Curtailable Demand (consisting of a minimum of 20% of Customer Load) or 500 kilowatts of Curtailable Demand (without restrictions), the Customer will be notified that service will no longer be provided under this Rider Schedule and any applicable Curtailment Agreement will be terminated.

If Demand history is not available, OPPD will review the operation of the facility with the Customer and determine reasonable Curtailable and Firm Demands.

Non-Compliance Charge for Failure to Reduce Load to the Firm Demand

For a July or August billing period, loss of credit for four (4) times the monthly credit per kilowatt of Curtailable Demand for all Demand exceeding the Firm Demand during any Curtailment Period. For a June or September billing period, loss of credit for two (2) times the monthly credit per kilowatt of Curtailable Demand for all Demand exceeding the Firm Demand during any Curtailment Period.

In the event of multiple failures to reduce Load within the same billing period:

- The loss of credit penalty will be applied once per kilowatt to the Customer's highest Demand recorded for all Demand exceeding the Firm Demand during the billing period; and
- For any monthly billing period, 50 cents per kilowatt-hour for all energy exceeding the Firm Demand level taken during each Curtailment Period.

If a Customer's failure to curtail to the Firm Demand when requested results in an OPPD purchase of capacity, the Customer will also reimburse OPPD for a proportionate share of this capacity cost. This reimbursement will be based on the current levelized cost of a combustion turbine peaking unit, including fixed capital and operation and maintenance costs. This charge will be increased by 23% to recover costs associated with the reserve margin and Demand losses on the transmission and distribution system. The resultant charge will be applied to the Customer's highest Demand recorded for all Demand exceeding the Firm Demand during a Curtailment Period. These charges will be assessed only once during the June 1 through September 15 period.

If the capacity purchase is less than the amount of Load not curtailed by the Customer, a pro-rated share of the capacity charge will be assessed to the Customer.

ADMINISTRATIVE

Definitions

Curtailable Demand: The Demand the Customer agrees to have available for curtailment within a four-hour notification period. The Demand is either at least 100 kilowatts consisting of a minimum of 20% of Customer Load or 500 kilowatts without restrictions. This Load can be curtailed and/or served by the Customer's Emergency Generating Units.

Curtailment Period:

Capacity Curtailment: May only occur when OPPD's projected Load is within 95% of the Deficit Load Condition, as determined by OPPD, or as directed by the Southwest Power Pool (SPP) by the Reliability Coordinator or Balancing Coordinator for OPPD, to reduce Load from June 1 through September 15, 12 P.M. to 10 P.M., Monday through Friday, excluding NERC Holidays. There is a maximum of 100 hours of Capacity Curtailment during a contract year.

Firm Demand: The Demand the Customer agrees not to exceed during a Curtailment Period. The Firm Demand is the Customer's Load that is not subject to curtailment.

Deficit Load Condition: The point at which OPPD's Load exceeds available capability, less net reserve capacity obligation, plus firm purchases, less firm sales.

Duration of Curtailment Period: The Curtailment Period will not exceed ten (10) hours.

Curtailment Notification: The Customer will be notified at least four (4) hours in advance of the time the Customer's Load must be curtailed. OPPD will specify that the Customer must not exceed the Firm Demand level during the Curtailment Period. Notification will be given to the Customer by at least 3 P.M. on the day of a curtailment.

Notice of a Curtailment Period will be by email.

OPPD will also follow-up the email with a telephone call to the Customer's designated official contact. The Customer will provide OPPD with the name, telephone number, and email address of the primary and secondary contacts. The inability of OPPD to reach the primary or secondary contacts by telephone will not relieve the Customer of the obligation of curtailing Load when an email notification is sent by OPPD.

Option to Change Curtailment Agreement

Annually, the Customer may make changes to the Curtailment Agreement, if agreed to by OPPD and incorporated into a new or amended Curtailment Agreement. The Customer must notify OPPD before January 1 to make a change for the following calendar year. If the Customer does not notify OPPD by December 31, the Customer will continue to be subject to the same curtailment for the following calendar year.

Rider Schedule Period

This Rider Schedule Duration is three (3) years. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.~~The Rider Schedule Duration, and the term of any Curtailment Agreement hereunder, will be three (3) years. The applicable Curtailment Agreement, at its expiration date, will automatically be renewed for an additional three (3) years, unless cancelled by written notice by either party at least six (6) months before the expiration date.~~

Mandatory Testing
OPPD will, at its discretion, conduct one curtailment test day (maximum 10 hours) per year between June 1 and September 15 for testing and compliance with the Rider Schedule.
The curtailment test day can be requested without regard to the Capacity Curtailment provision that the curtailment may only occur when OPPD’s projected Load is within 95 percent of the Deficit Load Condition. The hours tested during the curtailment test day will count toward the maximum hours of Capacity Curtailment during a contract year.

Non-Compliance Charge
If a Customer fails to reduce their Load to the Firm Demand level when requested to do so during more than one billing month during the Rider Schedule Duration, including the curtailment test days, the Customer will be subject to the Non-Compliance Charge and:

- Will be removed from this Rider Schedule, or
- The Curtailable and/or Firm Demand level will be adjusted at the discretion of OPPD, provided the resulting Curtailable Demand is not less than 100 kilowatts (consisting of a minimum of 20% of Customer Load) or 500 kilowatts (without restrictions).

Metering
OPPD will provide the necessary Load profile metering equipment and telephone connection to this equipment to administer this Rider Schedule. OPPD will also provide Demand pulses at the metering location for Customer-Owned Demand metering within the Customer's facility.

Special Conditions
OPPD will not be required to accept a level of Curtailable Demand with a Customer greater than OPPD reasonably believes the Customer is capable of providing.

OPPD retains the discretion to limit total participation and total Curtailable Demand under this Rider Schedule.

If OPPD does not require all of the Customers on this Rider Schedule to curtail during a Capacity Curtailment, the Customers that are requested to curtail will be determined at the sole discretion of OPPD. OPPD will rotate these curtailments among all of the Customers on this Rider Schedule.

Customers will not be able to enter into a Curtailment Agreement under this rider for the current calendar year after January 1.

The terms and conditions of the appropriate standard Rate Schedule applicable to the service rendered form a part of this Rider Schedule.

If the Customer elects to operate Emergency Generating Units in parallel with OPPD rather than curtail Load, the interconnection of this equipment with OPPD's system must meet the standards specified in the policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467E ~~OPTIONS E~~ & 467V

General Service – Emergency/Volunteer Curtailable
(Currently Unavailable for New Customers)

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, 245, or 250 that may voluntarily curtail a minimum of 100 kilowatts of Demand at one service location when requested by OPPD.

A Customer can only take service under Option E or Option V, not both.

BILLING COMPONENTS

Curtailment Credit Per Event

Option	Amount
467E	$10.25 kW/day
467V	$5.12 kW/day

At the end of each billing period, including a Curtailment Period, OPPD will determine the amount of Curtailed Demand during that month.

ADMINISTRATIVE

Curtailment Period

OPPD has the option of declaring a Curtailment Period, whether Emergency or Voluntary, at OPPD's sole discretion during the period of June 1 through September 15.

The duration of any curtailment will not exceed eight (8) hours per day. Curtailment Periods will only occur from12 P.M. to 10 P.M.

Curtailed Demand

The Demand (a minimum of 100 kilowatts) the Customer agrees to have available for the Curtailment Period when provided with a one-hour notification. This Load can be curtailed and/or served by the Customer's Emergency Generating Units.

OPPD will determine the Customer's Curtailed Demand during each billing period. This will be based on a comparison of the Load that would normally be placed on OPPD's system by the Customer during peak conditions with the Customer's Load observed during the Curtailment Period(s). A review of the Customer's actual Load profiles will be used for this comparison.

Curtailment Notification

Customers will be requested to curtail Demand with not less than one (1) hour notice from OPPD. Curtailment requests are at the sole discretion of OPPD.

OPPD will provide official notification of a curtailment request by email and will follow up on the email notification with a telephone call to the Customer's designated official contact. The Customer will provide OPPD with the name, telephone number, and email address of the Customer's primary and secondary contacts.

The Customer's primary or secondary contacts will indicate acceptance of OPPD's curtailment request by email. This acceptance will be regarded as notification by the Customer of intent to curtail a minimum of 100 kilowatts of Demand for the duration of the Curtailment Period at the price per the applicable Curtailment Credit section of this Rider. The Customer's failure to respond to OPPD's curtailment request before the start of the Curtailment Period will be regarded as an indication by the Customer that they will not curtail.

Schedule Period

This Rider Schedule Duration is one year. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.

~~This Rider Schedule duration is one year. Curtailment Agreements, at their expiration dates, will automatically be renewed for one year unless cancelled by written notice by either party at least sixty (60) days before the expiration dates.~~

Non-Compliance Penalties

Customers failing to curtail a minimum of 100 kilowatts of Demand for the duration of the Curtailment Period after notifying OPPD of their intention to curtail will forfeit any credits and may be removed from the Voluntary Curtailable Rider at the sole discretion of OPPD. For Emergency Curtailable Customers, failure to execute a request to curtail will also be considered non-compliance.

Metering

OPPD will provide the necessary Load profile metering equipment to administer this Rider Schedule.

Special Conditions

The terms and conditions of the appropriate standard Rate Schedule apply to the service rendered and form a part of this Rider Schedule.

If the Customer elects to operate Emergency Generating Units in parallel with OPPD rather than curtail Load, the interconnection of this equipment with OPPD's system must meet the standards specified in the policy for "Parallel Operation of Customer-Owned Generation Equipment." All required policies can be found at https://www.oppd.com.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 467L

General Service – ~~-~~ Curtailable – ~~-~~ Leased Capacity Option
(Currently Unavailable for New Customers)

APPLICABILITY

This Rider Schedule is applicable to all non-Residential Customers throughout OPPD's Service Area that own and operate electric generating facilities that are interconnected with OPPD's distribution facilities, subject to the terms of this Rider Schedule and applicable Leased Capacity Agreement. The Customer's facilities may normally be used to serve part or all of the Customer's electrical Load. The Customer must be capable of providing a minimum of 100 kilowatts to OPPD.

The decision to enter into a Leased Capacity Agreement with any Customer under this Rider Schedule is at the discretion of OPPD based on operational and market conditions. A Customer desiring to provide curtailable capacity to OPPD by utilizing Emergency Generating Units or by reducing Load may be served on Rate Schedule No. 467, but not this Rider Schedule.

This Rider Schedule is not available to those Customer accounts served under Rate Schedule Nos. 355 or 464~~, 355~~.

BILLING COMPONENTS

Monthly Credit:

Capacity Credit:

$4.60 per kW of Leased Capacity

Energy Credit:

25.00 cents/kWh

Reimbursement for energy generated is applicable only when requested by OPPD during the current billing period or during the performance of test procedures when requested by OPPD.

ADMINISTRATIVE

Definitions

Leased Capacity: Amount of capacity, in kilowatts, of the Customer's generating facilities made available to OPPD, as agreed to under a Leased Capacity Agreement. This amount will be determined through test procedures, as discussed below. This amount will not exceed the Customer's Billing Demand as defined under the regular Rate Schedule, applicable to the service rendered by OPPD, unless the Customer has Nebraska Power Review Board approval for these generating facilities.

Metering

OPPD will determine whether the Customer's generating facility metering is sufficient to monitor energy production. If it is determined that new and/or additional metering is required, OPPD will provide and install this metering at the Customer's cost.

Duration of Generating Facility Operation

The duration of any requested generating facility operation will be for a minimum of four (4) hours and a maximum of ten (10) hours, unless otherwise mutually agreed. These requests will occur year-round from 12 P.M. to 10 P.M., Monday through Friday, excluding NERC Holidays.

Curtailment Notification

The Customer will be notified at least four (4) hours in advance of the time the Customer must operate its generating facility. Notification will be given to the Customer by at least 3 P.M. on the day of a request to operate.

Notice of a request to operate will be by email.

OPPD will also follow-up the email with a telephone call to the Customer's designated telephone contact. The Customer will provide OPPD with the name, telephone number, and email address of the primary and secondary contact. The inability of OPPD to reach the primary or secondary contact by telephone will not relieve the Customer of the obligation of operating the Leased Capacity when an email notification is sent by OPPD.

Rider Schedule Period

This Rider Schedule Duration is three (3) years. The terms of any Curtailment Agreements hereunder will expire at their expiration dates.~~The Rider Schedule Duration, and the term of any Leased Capacity Agreement hereunder, will be three (3) years. The applicable Leased Capacity Agreement, at its expiration date, will automatically be renewed for an additional three (3) year periods unless cancelled by written notice by either party at least six (6) months before the expiration date.~~

Test Procedures

The tests to determine the Leased Capacity will be conducted jointly by OPPD and the Customer. The tests will be performed periodically at the request of either the Customer or OPPD and will be one-hour tests. The Customer will provide the personnel and equipment to perform the tests, and the Customer will record and document the tests. If a change in Leased Capacity is indicated it will be revised accordingly on the first day of the subsequent billing period, and the Customer and OPPD either will enter into a new Leased Capacity Agreement or amend the existing Agreement.

Increase in Leased Capacity

The Customer may install or enlarge its generating facilities, and subject to the approval of OPPD, add to the Leased Capacity made available to OPPD. OPPD will recognize the Leased Capacity as determined by the test procedures specified above, and the Customer and OPPD either will enter into a new Leased Capacity Agreement or amend the existing Agreement.

Non-Compliance Actions

If all, or part, of the Leased Capacity is not available to OPPD during any month, OPPD will have the right to suspend credit for that part of the Leased Capacity which is not available for that month or any subsequent month(s). Upon Customer's demonstration in accordance with the test procedures that all or part of the previously unavailable Leased Capacity is available, OPPD will resume the monthly credit for this capacity during the following month.

Absent this demonstration, OPPD may reduce the amount of Leased Capacity for the remainder of the term of the Leased Capacity Agreement.

In the event all or part of the Leased Capacity, excluding any scheduled maintenance, is not available when OPPD requests that power be generated, OPPD will provide written notice to the Customer of this non-compliance. If two of these notices are sent to the Customer in a two year period, OPPD will have the right to reduce the amount of the Leased Capacity for the remainder of the term of the applicable Leased Capacity Agreement. OPPD will provide the Customer with not less than fifteen (15) days written notice before exercising this right.

Scheduled Maintenance

The Customer will not schedule maintenance of the generating facilities between June 1 and September 15 of any calendar year. The Customer will provide 60-day prior notice of any scheduled maintenance to OPPD. The unavailability of generating facilities for scheduled maintenance will not exceed thirty (30) days.

Special Conditions

OPPD retains the right at its sole discretion to limit participation and the total amount of Leased Capacity it purchases through this Rider Schedule.

The terms and conditions of the appropriate standard Rate Schedule applicable to the service rendered form a part of this Rider Schedule.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 469 ~~AND OPTION~~& 469S

General Service – Time-of-Use

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, 245, or 250.

This Rider Schedule cannot be combined with Rider Schedule Nos. 464, 467, or 467L.

Option 469S is not available to Customers with a Billing Demand exceeding 150 kilowatts.

BILLING COMPONENTS

Monthly Rate: $56.40

Determination of Billing Demand

The Billing Demand for the applicable Rate Schedule will be adjusted as specified by the Determination of Billing Demand section of this Rider Schedule.

For the summer months, defined as the billing months of June through September 15, will be the greater of:

- The highest On-Peak Demand during the current month or the preceding eleven (11) months, or
- 33% of the highest Off-Peak Demand of the current month, or
- The Demand minimum of the applicable Rate Schedule.

For the non-summer months, defined as the billing months of September 16 through May, will be the greater of:

- The highest On-Peak Demand occurring during the preceding June through September 15 time period, or
- 33% of the highest Off-Peak Demand of the current month or preceding 11 months, or
- The Demand minimum of the applicable Rate Schedule.

If the Demand is less than 85% of the Customer's highest 15-minute kilovolt ampere Demand, OPPD will increase the Demand under this Schedule by 50% of the difference between 85% of the kilovolt ampere Demand and the Demand as determined above.

ADMINISTRATIVE

Definitions

On-Peak Demand: The kilowatts of Demand as determined from OPPD's Meter for the 15-–minute interval of the Customer's highest use during the billing period. The On-Peak Demand is set only between the hours of 12 Noon and 10:00 PM, Monday through Friday, from June to September, excluding Federal Holidays.

Option 469S –- *On-Peak Demand*: The kilowatts of Demand as determined from OPPD's Meter for the 15-minute interval of the Customer's highest use during the billing period. The On-Peak Demand is set only between the hours of 2:00 PM and 7:00 PM, Monday through Friday, from June to September, excluding Federal Holidays.

Off-Peak Demand: The kilowatts of Demand as determined from OPPD's Meter for the 15- minute interval of the Customer's highest use during the Off-Peak hours of the billing period. The Off-Peak hours are defined as all hours of the year not defined as on-peak hours.

Special Conditions

OPPD reserves the right to limit total participation and total On-Peak Demand on this Rate Schedule.

Customers taking service on this Rider Schedule are not eligible to be on OPPD's level payment plan.

For a Customer requesting to start on this Rider Schedule during an Off-Peak billing period, October to May, without a previously established On-Peak Demand, the Billing Demand will be determined by OPPD until such time that an actual On-Peak Demand is established. Once an actual On-Peak Demand has been established, the criteria defined in the determination of Billing Demand will apply.

Option 469S: Any Customer that exceeds an On-Peak Demand of 150 kilowatts or an Off-Peak Demand of 457 kilowatts during two billing periods within a twelve (12) month period will not be eligible for this Rider Schedule and will not be able to take service under this Rider Schedule again for a period of twelve (12) months. At the end of the twelve (12) months and OPPD's discretion, if OPPD's annual review of the historical Load indicates the Customer can maintain a maximum Billing Demand of no greater than 150 kilowatts, the Customer may be allowed take service under this Rider Schedule.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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SCHEDULE NO. 470

General – Customer Service Charges

APPLICABILITY

This Rider Schedule is applicable to all Customers, Contractors, and Developers for miscellaneous service operations.

BILLING COMPONENTS

Rates:

(470A): Activation Fee	
Non-landlords	$ 22.50
Landlords	$ 15.00
(470B): Reconnect Service after ~~d~~Delinquent B~~b~~ill D~~d~~isconnect	$ 75.00
(470C): Disconnect following U~~u~~nauthorized ~~r~~Reconnect – ~~-~~ ~~e~~Each O~~o~~ccurrence	$115.00
(470D): Field ~~c~~Collection ~~c~~Call – ~~-~~ ~~n~~No ~~d~~Disconnect	$ 30.00
(470E): Returned P~~p~~ayment ~~f~~Fee	$ 30.00

(470F): Line Extension ~~(Residential) C~~charges (Residential)

Underground service to new apartment complexes will be $30.00 per dwelling unit. All conduit and pull boxes are to be installed by the Customer.

200 Amp, 120/240 volt, 3-wire underground service in overhead areas will be billed at $1,050.00 each. The Customer is required to install a secondary conduit from the overhead service pole or pedestal to the Meter.

320 Amp, 120/240 volt, 3-wire underground service in overhead areas will be billed at $1,050.00 each. The Customer is required to install a secondary conduit from the overhead service pole or pedestal to the Meter.

Costs for underground dips exceeding 320 Amperes will be based on actual costs, plus overheads.

There is no charge to extend underground service to the closest Point of Entrance in Residential developments. Extensions beyond that point will be billed at $8.25 per foot.

Underground service to new subdivisions of normal configuration will be $1,500.00 per lot, where such lot is less than one acre, non-refundable. The Customer is required to install a secondary conduit from OPPD's service pedestal stub-out to the Meter. Effective, January 1, 2017, all underground services to new subdivision lots of normal configuration, where such lot is less than one acre and signed under an Underground Service Agreement before December 31, 2013, the Customer is required to install secondary conduit from OPPD service pedestal stub-out to the Meter.

The charge for temporary single-phase overhead service will be $326.00, including the activation fee.

The charge for temporary single-phase underground service will be $130.00, including the activation fee.

Rerouting an existing underground service to accommodate homeowner property changes will be charged at $19.62 per foot, with a $200 minimum charge.

(470G): Farm T~~t~~ransfer ~~s~~Switch C~~c~~harges to be ~~a~~Actual C~~c~~ost ~~p~~Plus O~~o~~verhead (ACPO)

200 A~~a~~mp T~~t~~ransfer ~~s~~Switch ~~–~~– ACPO

400 ~~a~~Amp T~~t~~ransfer S~~s~~witch ~~–~~– ACPO

(470H): Line ~~e~~Extensions and T~~t~~emporary S~~s~~ervice ~~d~~Disconnects ~~(General Service)~~ C~~c~~harges (General Service)

The underground service charge for new commercial or industrial developments for a primary backbone is $4,060.00 per acre.

200 Amp – ~~-~~ ~~a~~All standard voltages, commercial underground dip for single-phase service will be billed at $1,975.00 each.

320 Amp ~~-~~– ~~a~~All standard voltages, commercial underground dip for single-phase service will be billed at $1,975.00 each.

All ~~3~~three-phase underground commercial dips will be charged based on the estimated difference between underground costs vs. overhead costs.

The charge for temporary single-phase overhead service will be $326.00, including the activation fee.

The charge for temporary single-phase underground service will be $130.00, including the activation fee.

The charges for temporary service disconnects at the Customer's request will be as follows:

Guaranteed Start Time:

$250 per hour on Saturdays.

$375 per hour after 4:00 P.M. and before 9:00 A.M. on Monday through Friday.

$500 per hour on Sundays and OPPD designated holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and the day after Thanksgiving, Christmas Eve and Christmas Day or the days these holidays are observed by OPPD.

There is no charge during all remaining hours.

(470I): The Tenant Attachment Fee~~The tenant attachment fee~~

The annual tenant attachment fee for ~~the~~ joint use of OPPD's poles is $~~13.70~~16.00 per attachment~~ per year~~.

(470K): Miscellaneous Charges

Many of OPPD's Customer service charges are based on actual expenses incurred by OPPD. Examples of these charges include raising power lines for house moves, service reroutes, temporary relocations of systems during construction, emergency repairs of Customer-O~~o~~wned equipment and, at OPPD's discretion, information requests that require extensive research. All of these charges will be billed at the utility's costs plus overhead.

(470L): Overhead Costs

All charges that are based on actual costs will include the current transmission and distribution overhead rate.

(470M): Special Meter Reading d~~D~~ue to ~~an~~ Inaccessible Meter / Non-Automated Meter Read~~ (AMR)~~ Meter~~s~~

The charge for S~~s~~pecial Meter reading outside of the normal, automated Meter reading route due to an inaccessible or non-AMR (per reading) is $50.00

<u>ADMINISTRATIVE</u>

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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~~RIDER SCHEDULE NO. 480~~

~~Residential Surge Guard~~

~~APPLICABILITY~~

~~This Rider Schedule is applicable to Residential Customers having a 200 Amp service and a Meter Socket attached to their Premises, excluding apartments, flats or multi family units. This Rider Schedule provides Customers with protection against electrical surges at the Premises' wired entryways: OPPD Meter, phone box and cable box.~~

~~BILLING COMPONENTS~~

~~Monthly Service Charge: $6.99 per month~~

~~Additional Line Charge:~~

Line Type	Amount
Phone	$1.50 per line
Cable	$1.50 per line

~~Customers having equipment located outside of the Premises or needing additional special Arresters will be assessed additional fees based on actual costs and overhead.~~

~~Installation Charge:~~

~~Installation Type~~	~~Amount~~
~~Standard~~	~~$20.00~~

~~Additional charges may be assessed for installations requiring an electrician or other expenses.~~

~~ADMINISTRATIVE~~

~~Definitions~~

~~*Arrester*: Device to protect electrical equipment from over voltage transients caused by external (e.g. lightning) or internal (e.g. switching) events.~~

~~*Meter Socket*: Housing for electrical watt-hour Meter in Residential and commercial buildings.~~

~~Service Provided~~

~~OPPD will install three items on the Customer's Premises:~~

- ~~One Meter Socket Arrester~~
- ~~One cable TV line Arrester~~
- ~~One phone line Arrester~~

~~OPPD will provide up to $500 in warranty coverage for a Customer's electronic equipment, in the Customer's Premises and down line from OPPD's Arresters, against damage caused by direct electrical surges that do not pass through OPPD's Arresters (e.g., due to a direct lightning strike) up to a maximum of $500 per occurrence. The Customer must provide proof of surge damage in writing from the insurance carrier covering the Premises or from an electronics repair company designated by OPPD.~~

~~Service Regulations~~

~~The Customer under this Rider Schedule must comply with all OPPD Service Regulations.~~

Return to Rates and Riders List

~~RIDER SCHEDULE NO. 481~~

~~Commercial Surge Guard~~

~~APPLICABILITY~~

~~This Rider Schedule is applicable to all non Residential Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 230, 231, and 232.~~

~~BILLING COMPONENTS~~

~~Monthly Rate:~~

~~Service~~	~~Apparent Power~~	~~Amount~~
~~Single-phase~~	~~40 kVA~~	~~$9.95~~
~~Three-phase~~	~~40 kVA~~	~~$12.95~~
~~Three-phase~~	~~160 KVA~~	~~$16.95~~

~~$1.50 per line for any additional phone or cable lines for OPPD approved applications.~~

~~Customers having equipment located outside of the place of business or needing additional special arresters will be assessed additional fees based on actual costs plus overheads.~~

~~Installation Charge:~~

~~Single Phase~~	~~$125.00~~
~~Three Phase~~	~~$275.00~~

~~Additional charges may be assessed for installations requiring an electrician and/or other charges.~~

~~ADMINISTRATIVE~~

~~Schedule Period~~

~~The Schedule period is 2 Years. Termination of service within two years does not eliminate the monthly rate. The Customer may be responsible for unbilled charges.~~

~~Service Regulations~~

~~Customers under this Rider Schedule must comply with all OPPD Service Regulations.~~

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RIDER SCHEDULE NO. 483

Net Metering Service

APPLICABILITY

This Rider Schedule is applicable to all Customers in OPPD's Service Area with a Qualified Generator not taking service for the same Qualified Generator under Rider Schedule No. 355. This Rider Schedule is also not available to Customers taking service under Rate Schedule No. 357 – Municipal Service. Energy Storage systems capable of storing OPPD-supplied energy and exports that energy back to OPPD's system do not qualify.

DG Systems qualifying for Rider Schedule No. 483 shall not exceed 100kW in the aggregate system AC nameplate capacity, as determined by OPPD during the DG application and approval process.

BILLING COMPONENTS

Net Excess Generation Credit:

Excess Generation	Summer (June 1 – Sept. 30)	Non-Summer (Oct. 1 – May 31)
Per kWh	4.00 cents/kWh	3.52 cents/kWh

Determination of Customer Bill

The Customer can use Qualified Generator electrical output to supply all or a portion of the Customer's Demand and deliver the surplus to OPPD. At the end of the billing period, the net flow of the energy between the Customer and OPPD will be calculated, and the Customer's bill will be based on the net energy flow as follows:

- *Net flow from OPPD to the Customer:* The Customer will be billed for the net use at the monthly rate and based on the provisions included in the Customer's applicable Rate Schedule.
- *Net flow from the Customer to OPPD:* The Customer will be billed for the non-energy charges based on the provisions included in the Customer's applicable Rate Schedule and will receive a bill credit for the Net Excess Generation. If the bill credit is greater than the current month's billing, the Customer will carry an account credit balance for use in future months. At the end of the calendar year, any excess bill credits associated with Net Excess Generation will be paid to the Customer.

ADMINISTRATIVE

Definitions

Net Excess Generation: Production of more electrical energy than is consumed by the Customer during a billing period.

Special Conditions

Customers are responsible for Qualified Generator equipment and services required for interconnection. If desired, Customers are responsible for metering to measure the energy produced by the Customer's Qualified Generator. The Customer will maintain ownership of renewable energy credits associated with a Qualified Generator.

Customers taking service on this Rider Schedule are not eligible for OPPD's Level Payment Plan.

OPPD will provide, at no additional cost to the Customer, metering that is capable of measuring the flow of electricity in both directions. This equipment may be a single bidirectional Meter, smart Meter, two Meters, or another Meter configuration that provides the necessary information for service under this Rider Schedule.

Service Regulations

Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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RIDER SCHEDULE NO. 484

Supplemental Distribution Capacity

APPLICABILITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 231, 232, 245, 250 or 357.

BILLING COMPONENTS

A monthly charge based on the style of switch required to serve the Customer's Load:

Switch Style Charge*	Amount
PMH style ATO	$665.00
Upright Gear Non-Split Bus	$645.00
Upright Gear Split Bus-2 Sources	$1,885.00

**If applicable, this can be divided among multiple Customers. Please refer to Special Conditions for more information.*

Distribution System Capacity Charge of $1.41 per kilowatt of Demand

Demand will be determined from the "Determination of Demand" section of the applicable Rate Schedule.

OPPD will adjust the Demand when OPPD is requested to provide an additional source(s) of distribution capacity for partial Customer Load.

Minimum Monthly Bill

The Minimum Bill from the regular Rate Schedule applicable to the service rendered, plus the charges for the ATO Switch Charge and the Distribution System Capacity Charge, as applicable.

ADMINISTRATIVE

Rider Schedule Period

This agreement remains in place five years, with automatic renewal for additional one-year periods, as long as OPPD continues to provide the service as requested by the Customer under this Rider Schedule.

Service Provided

The Customer may request OPPD to provide an additional source(s) of distribution capacity to serve all or part of the Customer's Load as a contingency service when the normal distribution capacity is unavailable. OPPD may provide a manual throw-over switch for this service, or OPPD will provide an automatic throw-over (ATO) switch if the Customer requests the ATO. The ATO Switch Charge will not apply if a manual throw-over switch is provided.

Such additional source(s) of distribution capacity will be provided at OPPD's sole discretion if practical and safe, as determined by OPPD. Such service will not be provided if it would create an unusual hazard or interfere with the service provided to other Customers.

Disconnect Charge
Termination of service by a Customer at any time within the initial period under this Rider Schedule will not suspend or eliminate the ATO Switch Charge or the Distribution System Capacity Charge, specified above, for the months for which this service is terminated and will be applied to the final bill.

Special Conditions
All ATO switches for Customers will be supplied, installed, and maintained by OPPD.

If an ATO switch serves more than one Customer that has requested such service, the ATO Switch Charge will be divided equally among the Customers based on the number of Customers receiving such service. This calculation will be adjusted monthly if existing Customers discontinue service or if new Customers initiate service through this ATO switch.

Any investment required to connect the switch to the alternative distribution capacity source will be charged in accordance with OPPD's internal policies, including investments for new connections or upgrades to existing connections.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

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~~RIDER SCHEDULE NO. 490~~

~~Economic Development (*currently unavailable*)~~

~~APPLICABILITY~~

~~Electric Service under this Economic Development Rider Schedule (ECD) is available to Customers who:~~

- ~~Have agreed to locate new facilities or expand existing facilities in OPPD's Service Area,~~
- ~~Are receiving economic development benefits under the Nebraska Advantage Act, and~~
- ~~Meet the requirements specified in this Rider Schedule.~~

~~Service under this ECD Rider Schedule is available subject to the Nebraska Revised Statutes Section 70-655(2).~~

~~This Rider Schedule applies to a new Load associated with permanent service to new facilities or expanded Load related to the expansion of existing facilities. New or expanded Load at existing facilities must be demonstrated to serve new facilities and equipment and must be incremental to the facility's most recent historical Demand and energy at the time the Customer submits an application for service under this Rider Schedule.~~

~~This Rider Schedule does not apply to Loads associated with:~~

- ~~New or expanded facilities that are under construction or otherwise committed to operation before the effective date of this Rider Schedule, or~~
- ~~Which have been shifted from one existing Point of Delivery on OPPD's system to another Point of Delivery, or~~
- ~~That existed before the Customer entering into an Economic Development Service Agreement (ECDSA) as outlined in this Rider Schedule with OPPD.~~

~~Qualifications~~

~~The Customer's new or expanded Load must:~~

- ~~Qualify for and be delivered under Rate Schedules Nos. 232, 245, or 250, and~~
- ~~Have 2,500 kilowatts of Demand or greater during each monthly billing period, and~~
- ~~Have a minimum monthly billing period Load Factor of 60% for the new or expanded Load.~~

~~BILLING COMPONENTS~~

~~Economic Development Discount Calculation~~

~~OPPD will calculate an ECD discount percentage annually by February 1. This discount will be applied to all service agreements entered into after this date.~~

~~The discount percentage will be calculated for each applicable Rate Schedule for the discount period as follows:~~

- ~~The lowest resulting Rate Schedule discount percentage will be applied to Customers served under this Rider Schedule, regardless of Rate Schedule. In the event the resulting ECD discount percentage on a levelized basis is less than 2%, OPPD will not enter into new ECDSAs.~~
- ~~During the discount period, the minimum monthly Billing Demand will equal at least 75 percent of the maximum Demand specified in the ECDSA.~~
- ~~Upon completion of the discount term, the Customer will be required to pay for a minimum monthly bill during the non-discounted period as outlined in the ECDSA. Minimum Billing Demand will be 100 percent of the Customer's average monthly Billing Demand occurring in the last twelve (12) months of the discount period.~~

~~Application of the ECD Discount~~

~~The ECD Discount will be applied as a percentage discount to the portion of the bill associated with the general rates for the Customer's new or expanded Load, up to the maximum Load specified in the ECDSA, and will not apply to the FPPA (Rate 461), other Rate Schedules, and/or optional service charges.~~

~~If, in any given monthly billing period, the Customer does not meet the minimum Load and energy requirements as outlined in the ECDSA, the Customer will be billed at the rates shown on the applicable general Rate Schedule and this Rider Schedule will not apply.~~

~~The discount will not apply to a Customer's Load exceeding the maximum monthly Load specified in the ECDSA. Monthly Billing Demands above the maximum Billing Demand specified in the ECDSA will be billed at the full Demand charge associated with the applicable Rate Schedule. The ratio of undiscounted Billing Demand to total Billing Demand in the associated monthly billing period will be applied to total energy taken by the Customer in that billing period to determine the amount of energy that will not be discounted.~~

~~Available Capacity and Discount Availability~~

~~The capacity available to Customers under this Rider Schedule is limited to surplus capacity that OPPD projects will be available. The available capacity will be updated annually before June 1 and will be recalculated throughout the following twelve- (12) month period to reflect capacity committed to new ECD Customers under this Rider Schedule. If and when OPPD no longer has surplus capacity, service to new Customers under this Rider Schedule will not be available and OPPD will not enter into new ECDSAs.~~

~~Service under this Rider Schedule is based on the discount percentage, calculated annually under this Rider Schedule, equaling or exceeding 2%.~~

~~ADMINISTRATIVE~~

~~Definitions~~

~~*Load Factor*: The Customer's new or expanded energy use for the current billing period, divided by the quantity of the Customer's new or expanded Power Factor corrected Demand during the current billing period, multiplied by the number of days in the current billing period, multiplied by 24 hours.~~

~~Economic Development Application and Service Agreement~~

~~To be considered for service under this Rider Schedule, Customers must submit an ECD Application. Depending on OPPD's projected surplus capacity, and OPPD's then-current discount calculation as provided for in this Rider Schedule, OPPD may accept all or a portion of the proposed Load for service under this Rider Schedule or may reject the Application.~~

~~If the Application is accepted, the Customer and OPPD must enter into an Economic Development Service Agreement (ECDSA) for service under this Rider Schedule. The ECDSA will include but not be limited to the following:~~

- ~~Terms of the agreement,~~
- ~~Maximum and minimum monthly Demand and energy requirements under this Rider Schedule,~~
- ~~Discount percentage(s),~~
- ~~Billing and metering requirements and procedures and~~
- ~~Minimum bill requirements~~

~~Schedule Period~~

~~The term of service under this Rider Schedule will be a minimum of three (3) years and a maximum of five (5) years and is based on the Customer agreeing to take service at a non-discounted rate for an additional number of years equal to the term of discounted service under this Rider Schedule.~~

~~Ramp up provisions~~

~~Discounts under this Rider Schedule will begin no sooner than when the Customer's new or expanded Load reaches the minimum Demand and energy requirements as outlined in the ECDSA.~~

~~If the Customer fails to meet the minimum Demand and energy requirements within 18 months of the date of initiating permanent service:~~

- ~~The term of the respective discount and non-discount periods specified in the ECDSA will each be reduced by one month for each month between 18 and 24 months that the Customer's Load and energy requirements have not been met, and~~
- ~~The ECD Discount for the remaining term of the ECDSA will be subject to change to the lower of the then-current discount (for any new ECDSAs) or the discount included in the original ECDSA between the Customer and OPPD.~~

~~Termination~~

~~If the Customer's new or expanded Load has not reached the minimum Demand and energy requirements as outlined in the ECDSA within 24 months of the date of the signed agreement, the Customer will no longer be eligible for a discount under this Rider Schedule.~~

~~If, over the course of any 12 months, the Customer does not maintain the minimum annual average Demand and energy requirements as outlined in the ECDSA, the Customer will no longer be eligible for service under this Rider Schedule. For each of the remaining months of the ECDSA, the Customer's minimum monthly Billing Demand will equal 100 percent of the maximum Demand specified in the ECDSA.~~

~~Limitations~~

~~At any time during the discount period when, in OPPD's sole discretion, there has been a significant generation and/or market event that significantly impacts OPPD's production costs such that the ECD Discount included in the ECDSA is determined to no longer comply with the production cost provisions of the Nebraska Revised Statutes, OPPD reserves the right to recalculate the Economic Development Discount rate and reestablish the recalculated discount as the discount in the ECDSA. In this case, upon the Customer's request, the ECDSA may be revised to reflect a shortened term. In any case, the Customer will take and be required to pay for non-discounted service for the same amount of time the Customer took discounted service under this Rider Schedule.~~

~~If, in OPPD's opinion, the ECD discount will not significantly influence the Customer's decision to create or add Load in OPPD's Service Area, OPPD reserves the right to reject the ECD Application.~~

~~Special Conditions~~

~~This Rider Schedule is not available to a new Customer resulting from a change in Ownership of a new or existing facility. However, at OPPD's sole discretion, if a change in Ownership occurs after the Customer enters into an ECDSA for service to such facility, the successor Customer may have the option to fulfill the balance of the agreement as long as the subsequent Customer is receiving benefits under the Nebraska Advantage Act and has Load characteristics that are similar to the existing Customer's Load. In this case, the subsequent Customer will be obligated to fulfill both the remaining discount and non-discount terms of the original ECDSA.~~

~~Service Regulations~~

~~Customers under this Rider Schedule must comply with all OPPD Service Regulations.~~

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~~RIDER SCHEDULE NO. 499~~

~~Green Sponsorship - GSP~~

~~APPLICABILITY~~

~~This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under Rate Schedule Nos. 232, 245, or 250 and who adequately demonstrate that they will purchase a minimum 10,000,000 kilowatt-hours of energy annually from OPPD.~~

~~Customers will be eligible to participate in the process to purchase Environmental Attributes (EAs) for amounts of not less than 10,000,000 kilowatt-hours and not more than the Customer's annual energy usage.~~

~~This Rider Schedule applies to Customers who wish to achieve environmental sustainability goals by purchasing from OPPD exclusive EAs associated with renewable energy that is either from facilities owned by OPPD or procured by OPPD through a Purchased Power Agreement (PPA).~~

~~BILLING COMPONENTS~~

~~Green Sponsorship Charge (GSP Charge):~~

~~The monthly GSP Charge will be determined as follows: *Monthly*~~

~~*GSP Charge = (kWh * AWP) – (kWh * SPP$)* Where:~~

~~*AWP =* Gross EA price per kilowatt-hour. The AWP will include all costs associated with the additional renewable resources. In addition to the cost of renewable generation, the AWP will include all new transmission costs needed to transmit the renewable energy to market, integration costs, and administration costs. The price will have escalation terms that will cover future variable cost escalation (e.g., increase in PPA costs or operating costs.)~~

~~*kWh =* The monthly kilowatt-hour equivalent produced by generator for which the Customer has contracted.~~

~~*SPP$=* The average monthly net of all revenues and costs assessed by the Southwest Power Pool Integrated Market at the Contracted Renewable Facility settlement locations divided by the total kilowatt hours to determine average SPP$ per kilowatt-hour. All revenues and charges will be allocated by settlement date and will include but will not be limited to the day ahead, real time, and distribution charges such as losses, revenue neutrality and make-whole payments.~~

~~Monthly GSP Charge may be a charge or credit depending on the monthly net of all revenues and costs assessed by the SPP Integrated Market.~~

~~Determination of the GSP Bills~~
~~The monthly GSP charges and credits are independent and will not affect the calculation of any bills received for services from OPPD.~~

~~ADMINISTRATIVE~~
~~Definitions~~
~~*Environmental Attributes (EAs)*: All current and future attributes of an environmental nature, including but not limited to allowances, certificates, emission credits and all other credits, offsets, green tags and all other tags, and all similar rights issued, recognized, created or otherwise resulting from the generation of energy using wind, sunlight, water, biological processes or geothermal heat sources. EA's include, but are not limited to, those attributes that are created or recognized by regulations, statutes, or other action by a governmental authority and include, but are not limited to, those attributes that can be used to:~~

- ~~Claim responsibility for the reduction of emissions and/or pollutants.~~
- ~~Claim Ownership of emission and/or pollutant reduction rights.~~
- ~~Claim reduction or avoidance of emissions or pollutants.~~
- ~~Claim compliance with a renewable energy standard or renewable portfolio standard.~~

~~Special Conditions~~
~~The terms and conditions of the appropriate Rate Schedule apply to the service rendered.~~

~~Customers taking service under this Rider Schedule are purchasing EA's. Rights and/or claims to capacity, energy, and /or Production Tax Credits from renewable energy facilities are not being transferred or sold under this Rider Schedule.~~

~~OPPD reserves the right to maintain a renewable portfolio based on market conditions and its ability to integrate the renewable energy into its portfolio on an economic basis.~~

~~Any renewable energy facilities developed to meet the Customer's requests under this Rider Schedule will be located in Nebraska, unless OPPD and the Customer requesting EA's mutually agree to negotiate a power purchase agreement for a renewable energy facility in another state located within the SPP territory.~~

~~Available Renewable Energy Credits~~
~~OPPD will determine the need to acquire new resources to meet the obligation to serve retail Customers. The evaluation will include the determination of the amount of additional renewable resources required to meet its own portfolio needs and EA Customer sponsorship requests. Customer sponsorship requests will be determined by an application process for Customer interest in purchasing EAs.~~

~~In acquiring new resources, OPPD will determine the capacity to provide renewable resources to meet Customer requests beyond OPPD's renewable needs. OPPD would then seek applications from Customers to register for the purchase of EAs associated with such resources.~~

~~At that point, OPPD would negotiate with qualifying Customers that apply for the service to arrange a long term Green Sponsorship Sales Agreement (GSSA) with the Customer that is in the best interest of all parties and conforms with all current regulations required to purchase, build and/or contract for attributes in Nebraska and/or within the Southwest Power Pool (SPP). If, in the end, aggregate Demand for the EAs exceeds availability, the EAs will be apportioned on a fair and reasonable basis among parties meeting the requirements of this Rider Schedule.~~

~~EAs are not available for OPPD's existing renewable resources or those to which OPPD has previously contracted for renewable energy. OPPD does not guarantee the availability of renewable energy facilities or approval of any projects by OPPD's Board of Directors or any regulatory authority.~~

~~Service Regulations~~
~~A Customer under this Rider Schedule must comply with all OPPD Service Regulations.~~

Return to Rates and Riders List

RIDER SCHEDULE NO. 500

Community Solar

APPLICAIBLITY

This Rider Schedule is applicable to all Customers throughout OPPD's Service Area taking service under any Retail Rate Schedule.

BILLING COMPONENTS

Refundable Enrollment Deposit:

Residential Customers on Rate Schedules 110 and 115 will be charged a $100 refundable enrollment deposit to begin participation under this rate Rider Schedule. All other Customer rates will be assessed a refundable enrollment deposit based on the greater of $100 or a combination of the average usage of the rate class and the Community Solar subscription level as agreed upon in the Community Solar Service Agreement.

OPPD will refund this deposit if the Customer participates in this rate Rider Schedule for:

- Five (5) consecutive years for Rate Schedules 110 and 115
- Ten (10) consecutive years for Rate Schedules 226, 230, and 231
- Twenty (20) consecutive years for Rate Schedules 232, 245, 250 and 261M

If a Customer elects to end participation under this rate Rider Schedule before the above requirements, the refundable enrollment deposit will be forfeited.

Community Solar Charge:

Community Solar Charge = Market Based Value of Solar * Subscription Level

ADMINISTRATIVE

Definitions

Subscription Level: Quantity of Community Solar Share(s).

Community Solar Share: 100 kWh per month.

Market-Based Value of Solar: Calculated on a per-share cost and is defined as the interconnected cost of the community solar Purchased Power Agreement (PPA), less the actual hourly community solar production from the prior year valued at the corresponding Southwest Power Pool (SPP) day-ahead hourly prices, less the accredited capacity assigned by SPP to the community solar facility(s) valued at the annual levelized value of OPPD's next marginal generation capacity.

Special Conditions

Service under this Rider will be limited to the aggregate amount of generation available by all community solar PPAs.

The Community Solar Service Agreement may be revised periodically by OPPD.

The Community Solar kWh Charge will be updated annually, as stated in the Community Solar Service Agreement.

Service Regulations
Customers under this Rider Schedule must comply with all OPPD Service Regulations.

Your Energy Partner®

OPPD

Omaha Public Power District

Action Item

BOARD OF DIRECTORS

December 17, 2024

ITEM

2025 Corporate Operating Plan and Rate Action

PURPOSE

Submittal of the 2025 Corporate Operating Plan and rate action for approval by the Board of Directors.

FACTS

a. The Corporate Operating Plan includes a total average rate impact across all customers classes of 6.3%.

- The Fuel and Purchased Power Adjustment (FPPA) accounts for 0.4% of the rate impact. The current FPPA factor is 0.413 cents per kWh. Due to an under-collection in 2024 mainly from winter storm Gerri, management will propose to increase the Fuel and Purchase Power factor to 0.457 cents per kWh.
- A 1.0% rate impact for replenishment of the Rate Stabilization Reserve is included in the average general rate increase across all customer classes of 5.9%. The Rate Stabilization Reserve will be used in 2024 to meet 2.0 debt service coverage, whose usage is currently projected at $13.3 million and will be updated with actual results through December 2024. Usage of the Rate Stabilization Reserve was primarily driven by generation outages and storm restoration costs.

b. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used as a baseline to determine the appropriate rate increase for each class.

Customer Class	FPPA Rate	General Rate	Average
Residential	0.4%	8.0%	8.4%
Commercial	0.5%	4.0%	4.5%
Industrial	0.3%	5.1%	5.4%
Lighting	0.1%	8.0%	8.1%
Wholesale Towns	0.6%	8.0%	8.6%
Average	0.4%	5.9%	6.3%

The proposed increases are detailed on Exhibit A (attached).

c. Miscellaneous wording and rate changes to various rate schedules are also proposed. These proposed changes are detailed in Exhibit B (attached).

d. Total energy sales are budgeted to be 18,879 GWh which represents an 8.5% increase from the budgeted 2024 sales amount.

- Retail sales are budgeted to be 15,355 GWh which represents a 12.5% increase from the budgeted 2024 amount.
- Wholesale revenues, excluding Nebraska City Station Unit 2 (NC2) participation sales, are budgeted to be 1,629 GWh which represents a 1.5% decrease from the budgeted 2024 amount.
    - NC2 participation sales for 2025 are budgeted to be 1,895 GWh, a 9.6% decrease from the budgeted 2024 amount.

e. Total operating revenues are budgeted to be $1,671.2 million. Total budgeted operating revenues are 16.7% higher than the 2024 budget.

- Retail revenues are budgeted to be $1,434.4 million, which is an increase of $208.7 million or 17.0% above the 2024 budget.
- Wholesale revenues, excluding NC2 participation revenues, are budgeted to be $119.6 million, which is 18.5% higher than 2024 budgeted revenues.
    - NC2 participation revenues for 2025 are budgeted to be $70.5 million, a 10.9% increase from the budgeted 2024 amount.

f. Total operations and maintenance expenditures are budgeted to be $1,149.9 million. Total operations and maintenance expenditures are $128.8 million or 12.6% higher than the 2024 budgeted amount.

- Operations and maintenance expenditures (excluding fuel and purchased power) are budgeted to be $582.7 million, which is $54.4 million or 10.3% higher than the amount budgeted for 2024.
- Fuel expenses are budgeted to be $187.4 million which is $7.3 million or 4.0% higher than the amount budgeted for 2024.
- Purchased power expenses are budgeted to be $379.7 million which is $67.2 million or 21.5% higher than the amount budgeted for 2024. The purchased power expenses include 1,272 megawatts of wind capability and 86 megawatts of solar capability, to support the District's renewable energy goal.

g. Capital expenditures are budgeted at $788.0 million for 2025 compared to $727.0 million budgeted for 2024.

The 2025 capital expenditure plan provides for expansion and improvements to the existing production, transmission and distribution systems. Expenditures by classification include both approved and pending capital projects. Actual expenditures by classification will vary based on final project designs, corporate priorities, and pending project approvals.

Production	$ 330.6 million
Transmission and Distribution	338.6 million
General	118.8 million
TOTAL	$788.0 million

h. In 2025, funding for Nuclear Decommissioning is budgeted at $10.7 million, consisting of investment earnings on trust balances.

i. Net income for 2025 is budgeted to be $203.1 million compared to $161.4 million budgeted for 2024.

j. The 2025 Corporate Operating Plan total expenditure amount equals $2,323.6 million.

k. Total debt service coverage is anticipated to be 2.0 times for 2025.

ACTION

Approval of the 2025 Corporate Operating Plan and rate changes.

RECOMMENDED:

Signed by:
Jeffrey M. Bishop
65F902772CFE45A...

Jeffrey M. Bishop
Vice President and Chief Financial Officer

APPROVED FOR BOARD CONSIDERATION:

Signed by:
L. Javier Fernandez
AC399FDCE56247E...

L. Javier Fernandez
President and Chief Executive Officer

Attachments: 2025 Corporate Operating Plan
Letter from The Brattle Group – Financial Review
Letter from The Brattle Group – Rates Review
Exhibit A – Proposed Rate Adjustments
Exhibit B – Proposed Service Regulations and Schedules Revisions
Red-line of full Service Regulations and Schedules
Resolution