Board Action

Spurgeon/Bishop

RESOLUTION NO. 6621

WHEREAS, the Board of Directors has reviewed the Omaha Public Power District's 2024 Corporate Operating Plan, which includes projected revenues and expenses for the District's operations in 2024, all phases of the District's 2024 Capital Expenditure Plan, and the District's fuel needs and expenditures for 2024; and

WHEREAS, the 2024 Corporate Operating Plan expenditures total $2,107.7 million; and

WHEREAS, the proposed 2024 Corporate Operating Plan reflects the need for the District to increase its rates by an average of 2.5% 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 Omaha Public Power District includes a revision to the FPPA base rate from 1.606 cents per kWh to 1.951 cents per kWh. The FPPA factor will decrease to 0.413 cents per kWh from 0.480 cents per kWh. The net results of the resetting of the FPPA base and impact on FPPA factor is a -0.6% average rate impact. The 2024 Corporate Operating Plan includes a one-time 100% exclusion of under-collected FPPA revenue due to favorable financial results, which is currently projected to be $6.8 million and will be updated with actual results through December 2023; and

WHEREAS, District Management prepared a Cost of Service Study for each customer class and applied this analysis to establish the proposed 3.1% 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, the District's rate consultant, The Brattle Group, has reviewed the 2024 Corporate Operating Plan and 2024 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:

1. The 2024 Corporate Operating Plan is hereby approved.

2. The rate changes described in Exhibit A and as set forth in the Rate Schedules attached in Exhibit B are herby approved, effective January 1, 2024.

3. As described in Exhibit B, the following definition is revised: Qualified Generator.

BOARD OF DIRECTORS

4. As described in Exhibit B, the following District Rate Schedule is repealed, effective January 1, 2024: Rate Schedule 261 Large Power – High-Voltage Transmission Level.

5. As described in Exhibit B, the revisions to the following Rate Schedules and Riders are hereby approved: Rate Schedules 350 (Municipal Service – Street Lighting); Rider Schedule 461 (Fuel and Purchased Power Adjustment), Rider Schedule 470A (Activation Fee Non-landlords and Landlords), 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 herby approved.

2024 Corporate Operating Plan

OPPD
Omaha Public Power District

ILLUMINATE OUR FUTURE

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Omaha Public Power District

Management Letter

Management Letter

2023 will be a year that is long remembered at Omaha Public Power District. We are seeing unprecedented load growth across our service territory; our board of directors made a historic generation decision, and we have continued to execute the work outlined in our Powering the Future to 2050 vision. This work will power our customers and their evolving needs for decades to come.

OPPD's service territory is growing at an unprecedented rate. We estimate the demand for energy will increase at approximately 100 megawatts (MW) each year for the next decade. That level of growth is considerably higher than the 4 MW-per-year rate we traditionally experience.

This growth is creating opportunity and challenges for OPPD as we navigate serving customers' changing needs. In August, the OPPD Board of Directors approved additional generation totaling approximately 2.5 gigawatts (GW), nearly doubling our current generation output. This additional energy will power our growing customer classes, including data centers and residential growth.

As our economy continues to digitize, data centers are a growing segment of our vibrant economy and also a growing segment of our customer base, consuming considerable amounts of energy. These centers are powering the ever-changing lives of the residents of our service territory, who rely on electricity more than ever to power the technology in their homes and daily lives for decades to come.

Our 2024 Corporate Operating Plan includes a modest rate increase with an average impact of 2.5% across all customer classes. Driving the rate increase is net power costs and a growing capital portfolio. Net power costs are growing as the average price per megawatt to serve load is increasing within the marketplace. Capital costs are increasing due to the District's efforts to expand and modernize the electrical grid to maintain reliability while meeting the needs of a growing community. While we do have a rate increase, using the most current 2022 data from the Energy Information Administration, OPPD's average retail rate is still 26.5% below the national average.

Speaking of the future, we continue to move forward to meet our "north star" vision, called Powering the Future to 2050. This vision is guiding and prioritizing work across the utility. One piece of this vision is our advanced metering infrastructure (AMI) work, which will modernize our electrical system and enable customers to have a more detailed view of their energy usage. The improvements will also tell us when a customer is without power without the customer needing to notify us. This project involves extensive upgrades to our infrastructure and data management systems.

Besides new generation and a modernized system, we are also working towards solutions as part of our Master Facilities Plan, including the future expansion of existing facilities that are critical to our operations.

It's an exciting time at OPPD, where we are seeing many of the same challenges as our public power peers nationwide. The energy landscape is moving at a rapid pace, and we are charging forward to meet the challenge.

L. Javier Fernandez
President and Chief Executive Officer

Omaha Public Power District

Strategic Planning and Enterprise Risk Management

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 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.

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
	Equivalent Availability	Maintaining steam unit equivalent availability factor at or above 90% on a three-year rolling average	90%
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 Zero Carbon	By year end 2027, achieve an approximate 3,500,000 ton annual reduction in CO2 emissions at the North Omaha Station site relative to OPPD's 2013 benchmark of 3,960,179 tons at the station	3.5 million tons/year *
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

** Metrics will be revisited in Q1 2024*

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.

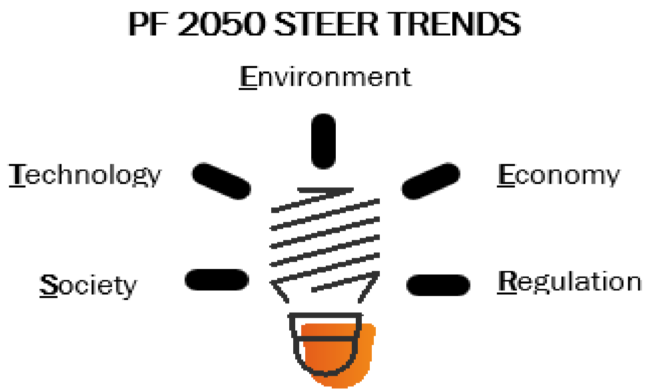
The Board of Directors established SD-7 (Environmental Stewardship) with the goal to conduct all operations in a manner that strives for the goal of net-zero-carbon production by 2050. In consideration of this revision, other SD policies, and transformational changes within and outside the industry, 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 five-year 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 2024-2028 enterprise priorities (listed in priority order) 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 & Investment
3. Two-way Communication & Engagement
4. Master Facilities Plan

OPPD leveraged PF2050 and the five-year enterprise priorities to guide planning, prioritization, and resourcing decisions for this Corporate Operating Plan. 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

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 this year. 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 2024 corporate planning efforts, OPPD leveraged risk assessments and mitigation plans to help prioritize resource allocation. The ELT has initiated and 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.

Omaha Public Power District

Assumptions

Assumptions

2024 Proposed Rate Action

OPPD's 2024 Corporate Operating Plan assumes an average total rate increase of 2.5% across all customer classes, composed of a 3.1% average general rate increase and a 0.6% decrease in the Fuel and Purchased Power Adjustment (FPPA) factor effective January 1, 2024.

General

2023 Projected

Revenues, operations and maintenance, capital and deferred expenditures reflect the 2023 actual values and forecast submitted through September 30, 2023.

Financing/Investing

Financing

Revenue bonds with net proceeds of $424.0 million are included in the 2024 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 2024 is 4.1% which is an increase of 0.7% from the prior year's rate of 3.4%.

Energy Sales/Revenues

Load Forecast

The plan assumes a 9.5% increase in retail energy sales (MWh) and a 1.1% increase in the number of customers in 2024, as compared to the 2023 projection.

Assumptions

Generation and Purchased Power

Outages have been scheduled for the following base-load units in 2024:

1. Nebraska City Station Unit Number 1
2. North Omaha Station Unit 5

Additionally, there are several shorter outages scheduled for other units. The purchased power budget includes generation supplied from 972 megawatts of wind capability, 80 megawatts of hydropower from the Western Area Power Administration, as well as 5 megawatts of Fort Calhoun Community Solar capability. In addition to the existing facilities, multiple generating stations are expected to be operational in 2024. Platteview Solar, an 81-megawatt utility-scale solar generation facility, as well as two natural gas peaking stations, Turtle Creek and Standing Bear Lake, will add to OPPD's generation fleet.

Department Operations and Maintenance Budget

Department and division level budgets were proposed in August 2023 during the Resource Optimization Sessions. These plans were reviewed with the Executive Leadership Team for alignment with the strategic and operational objectives before submitting them in the 2024 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 2024 Budget

The total 2024 Budget is $2.1 billion.

BUDGET SUMMARY
(DOLLARS IN THOUSANDS)

Total Budget

	BUDGET 2023	BUDGET 2024	INCREASE / (DECREASE)	% CHANGE
Fuel Costs and Purchased Power	$462,867	$492,691	$29,824	6.4
Non-Fuel Operations & Maintenance	481,800	528,335	46,535	9.7
Total Debt Service and Other Expenses	164,149	189,242	25,093	15.3
Payments in Lieu of Taxes	42,065	45,599	3,534	8.4
Capital Expenditures*	640,000	727,000	87,000	13.6
Contributions to Decommissioning & Benefit Reserve	0	11,939	11,939	100.0
Regulatory Amortization	13,602	0	(13,602)	(100.0)
Decommissioning Expenditures**	115,301	112,918	(2,383)	(2.1)
TOTAL BUDGET	**$1,919,784**	**$2,107,724**	**$187,940**	**9.8**

*Capital Expenditures are shown net of Contributions in Aid of Construction
**Decommissioning Expenditures represent expenditures related to Decommissioning activity, which differs from Decommissioning Funding ($15.3 million) which is an expense and is reflected on the income statement.

Budget Component Comparison

	BUDGET 2023	BUDGET 2024	CHANGE
Fuel Costs and Purchased Power	24.1%	23.4%	(0.7)
Non-Fuel Operations & Maintenance	25.1%	25.1%	0.0
Total Debt Service and Other Expenses	8.6%	9.0%	0.4
Payments in Lieu of Taxes	2.2%	2.2%	0.0
Capital Expenditures*	33.3%	34.5%	1.2
Contributions to Decommissioning & Benefit Reserve	0.0%	0.6%	0.6
Regulatory Amortization	0.7%	0.0%	(0.7)
Decommissioning Expenditures**	6.0%	5.4%	(0.6)
TOTAL BUDGET	100%	100%	0.2

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

Fuel and Purchased Power Budget

	BUDGET 2023	BUDGET 2024	INCREASE / (DECREASE)	% CHANGE
Fuel Cost	$165,301	$180,164	$14,863	9.0
Purchased Power	297,566	312,527	14,961	5.0
TOTAL BUDGET	**$462,867**	**$492,691**	**$29,824**	**6.4**

Non-Fuel O&M Budget

	BUDGET 2023	BUDGET 2024	INCREASE / (DECREASE)	% CHANGE
Production	$131,925	$147,748	$15,823	12.0
Transmission and Distribution	150,401	166,553	16,152	10.7
Customer Accounting and Services	47,881	47,096	(785)	(1.6)
Administrative and General	151,593	166,938	15,345	10.1
TOTAL BUDGET	**$481,800**	**$528,335**	**$46,535**	**9.7**

Debt Service/Other Expenses

	BUDGET 2023	BUDGET 2024	INCREASE / (DECREASE)	% CHANGE
Bonds	$169,510	$194,308	$24,798	14.6
Commercial Paper	8,750	10,000	1,250	14.3
Other	(14,111)	(15,066)	(955)	6.8
TOTAL BUDGET	**$164,149**	**$189,242**	**$25,093**	**15.3**

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

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Income Statement

Projected net income for 2023 is $145.5 million, which is $49.0 million over budget. Higher net income is primarily driven by decreased decommissioning and depreciation expense, partially offset by lower retail revenue and elevated operations and maintenance expense. It should be noted that OPPD does not set budgets and other forward looking plans on the basis of net income. 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.

Net income for 2024 is budgeted to be $161.4 million, which is $15.9 million higher than the 2023 projected net income. When compared to the 2023 budget, net income for 2024 is $65.0 million or 67.3% higher.

Major factors contributing to the change in 2024 operating and net income are:

1. Operating revenues are budgeted to be $23.0 million higher than 2023 projections and $31.1 million higher than the 2023 budget. Retail revenues are expected to increase $67.5 million from 2023 projections and increase $61.2 million when compared to the 2023 budget, which is related to growth in the Industrial and Commercial customer classes. The increases in retail sales were partially offset by a decrease in wholesale revenues of $42.7 million compared to 2023 budget and $32.6 million compared to 2023 projection, primarily driven by decreased congestion hedging revenues.

2. Operations and maintenance expense is budgeted to be $0.6 million lower than the 2023 projected amount and $76.4 million higher than the 2023 budgeted amount. The 2024 budget is consistent with the 2023 projection due to elevated purchased power and production expenses in 2023 related to operating interruptions, as well as an unplanned pension contribution.

3. Other income for 2024 is $5.5 million higher than the 2023 projected amount. Other income budgeted for 2024 is $27.1 million higher than the 2023 budget amount primarily due to increased investment income resulting from higher cash balances and higher average earnings rates.

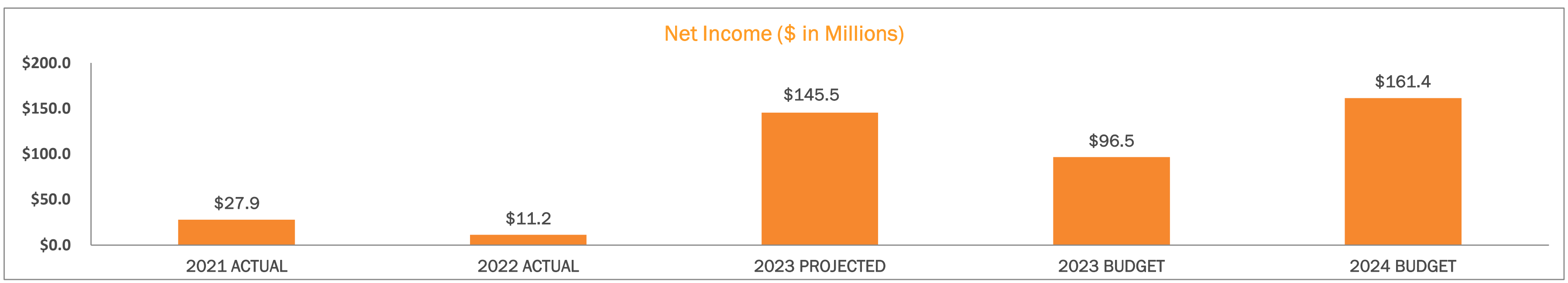
4. Total decommissioning funding, which is recognized as an expense of $15.3 million in 2024, is $19.4 million lower than 2023 projected and $79.9 million lower than 2023 budget due to discontinuing contributions as the decommissioning trust is fully funded.

5. Depreciation expense, which does not impact the Debt Service Coverage metric, is $138.4 million in 2024, which is $13.6 million greater than 2023 projection and $18.3 million lower than 2023 budget. Recently, a depreciation study was conducted which greatly reduced projected 2023 annual depreciation expense compared to budget. The increase in 2024 budgeted depreciation expense is the result of a growing asset base.

INCOME STATEMENT
(DOLLARS IN THOUSANDS)

Income Statement

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
OPERATING REVENUES	$1,496,920	$1,400,784	$1,409,309	$1,401,221	$8,088	$1,432,358	$23,049	1.6
OPERATING EXPENSES								
O&M EXPENSE	1,093,592	962,458	1,021,587	944,666	76,920	1,021,028	(559)	(0.1)
PAYMENTS IN LIEU OF TAXES	38,555	40,462	42,643	42,065	578	45,599	2,955	6.9
DECOMMISSIONING EXPENSE	132,543	141,918	34,703	95,168	(60,465)	15,298	(19,406)	(55.9)
REGULATORY AMORTIZATION	14,836	14,835	13,600	13,602	(2)	0	(13,600)	(100.0)
DEPRECIATION EXPENSE	142,156	150,074	124,878	156,567	(31,688)	138,448	13,570	10.9
TOTAL OPERATING EXPENSE	$1,421,682	$1,309,747	$1,237,411	$1,252,068	($14,657)	$1,220,373	($17,039)	(1.4)
OPERATING INCOME	$75,238	$91,037	$171,897	$149,153	$22,745	$211,985	$40,088	23.3
INTEREST INCOME*	19,439	20,481	33,322	27,152	6,171	54,211	20,889	62.7
MARK TO MARKET	(22,725)	(60,693)	9,080	0	9,080	0	(9,080)	(100.0)
ALLOWANCE FOR FUNDS USED	9,772	16,427	31,028	25,369	5,660	26,332	(4,696)	(15.1)
PRODUCTS AND SERVICES - NET	1,830	2,868	2,121	3,400	(1,279)	2,484	362	17.1
MISC. NON OPERATING INCOME	12,931	25,917	4,990	3,000	1,990	3,000	(1,990)	(39.9)
TOTAL OTHER INCOME	$21,246	$5,000	$80,542	$58,921	$21,621	$86,027	$5,485	6.8
TOTAL INCOME LESS OPERATING EXPENSE	$96,485	$96,037	$252,439	$208,073	$44,366	$298,012	$45,573	18.1
INCOME DEDUCT. & INT. CHARGES								
INTEREST EXPENSE	78,800	97,739	119,951	125,671	(5,720)	151,720	31,769	26.5
AMORTIZATION	(12,210)	(14,694)	(15,616)	(15,316)	(299)	(16,271)	(655)	4.2
OTHER INCOME DEDUCTIONS	1,947	1,787	2,634	1,205	1,429	1,205	(1,429)	(54.2)
TOTAL INCOME DEDUCT. & INT. CHARGES	$68,537	$84,832	$106,969	$111,560	($4,591)	$136,654	$29,685	27.8
NET INCOME	$27,948	$11,205	$145,470	$96,513	$48,957	$161,358	$15,888	10.9



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

Financial Statements

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 2024, as directed by SD-3 Access to Credit Markets.

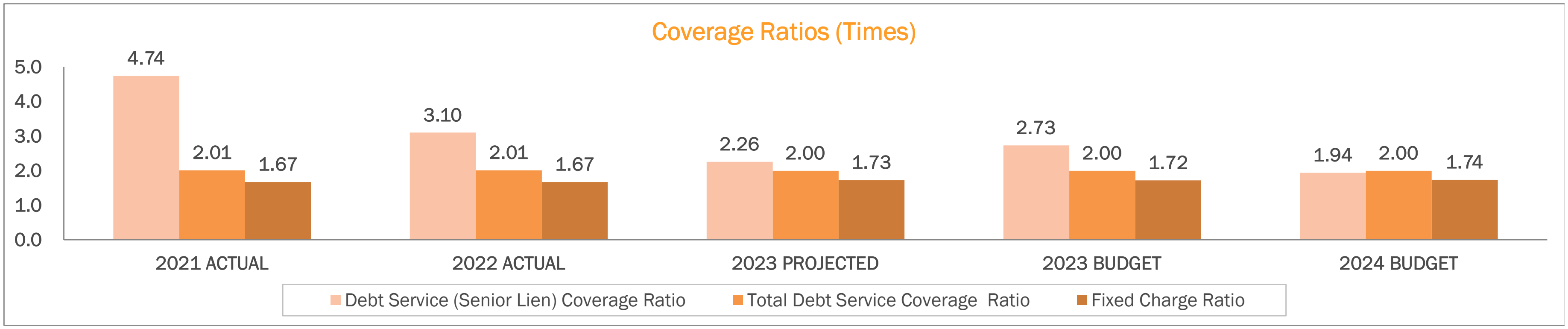
The Fixed Charge ratio is budgeted at 1.74 times in 2024, as compared to the projected 2023 of 1.73 times.

The Senior Lien Debt Service Coverage ratio is projected to be 2.26 times in 2023 and 1.94 times in 2024. The decrease is driven by an increase in senior lien debt service requirements, partially offset by an increase in net receipts. Net receipts for 2024 are expected to increase by $47.1 million or 15.0% from 2023 projected levels primarily due an increase in revenues and decreasing operations and maintenance expenses. Senior lien debt service requirements for 2024 are scheduled to increase by approximately $46.9 million over 2023 projections as a result of the 2023 and 2024 bond issues.

COVERAGE RATIOS
(DOLLARS IN THOUSANDS)

Coverage Ratios

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
OPERATING REVENUES (EXCL. NC2)	$1,426,672	$1,331,698	$1,340,625	$1,331,828	$8,797	$1,368,804	$28,179	2.1
INTEREST INCOME - BONDS RESERVE ACCOUNT	1,077	1,357	2,992	2,066	926	3,491	499	16.7
O&M EXPENSE (EXCL. NC2 PARTICIPANT SHARE)	(1,054,372)	(930,054)	(987,609)	(899,143)	(88,466)	(966,215)	21,394	(2.2)
PAYMENTS IN LIEU OF TAXES	(38,555)	(40,462)	(42,643)	(42,065)	(578)	(45,599)	(2,955)	6.9
NET RECEIPTS	$334,822	$362,539	$313,364	$392,686	($79,321)	$360,481	$47,117	15.0
DEBT SERVICE REQUIREMENTS (SENIOR LIEN)	$70,582	$116,947	$138,241	$143,690	($5,449)	$185,183	$46,942	34.0
DEBT SERVICE (SENIOR LIEN) COVERAGE RATIO	4.74	3.10	2.26	2.73		1.94		
MEMO: OTHER COVERAGE RATIOS:								
TOTAL DEBT SERVICE COVERAGE RATIO (DSC)	2.01	2.01	2.00	2.00		2.00		
FIXED CHARGE RATIO	1.67	1.67	1.73	1.72		1.74		



NOTES: 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 2024 are budgeted to equal $2,842.5 million. The 2024 budget anticipates the issuance of approximately $448.7 million of new senior lien revenue bonds and also includes senior lien revenue bond maturities and retirements of $45.9 million.

Total subordinated bonds outstanding at year-end 2024 are budgeted to equal $132.2 million and also includes subordinated bond maturities and retirements of $2.6 million. The 2024 budget does not anticipate the issuance of new subordinated bonds.

Total commercial paper outstanding at year-end 2024 is budgeted to equal $250.0 million. The 2024 budget does not anticipate the retirement or issuance of new commercial paper.

Total separate system (NC2) revenue bonds outstanding at year-end 2024 are budgeted to equal $189.5 million. The 2024 budget does not anticipate the issuance of new NC2 revenue bonds, but does have NC2 revenue bond maturities and retirements of $4.2 million.

The total average interest rate on existing debt will be 4.21% at the end of 2023 and 4.44% at the end of 2024. The debt to capitalization ratio is budgeted to be 66% for 2024.

DEBT AND FINANCING DATA
(DOLLARS IN THOUSANDS)

Debt and Financing Data

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
SENIOR LIEN REVENUE BONDS								
BALANCE - BEGINNING OF YEAR	$1,208,640	$1,524,630	$1,935,320	$1,935,320	$0	$2,439,775	$504,455	26.1
MATURITIES / RETIREMENTS	(122,945)	(9,875)	(45,305)	(45,305)	0	(45,895)	(590)	1.3
NEW ISSUES	438,935	420,565	549,760	504,000	45,760	448,657	(101,103)	(18.4)
BALANCE - END OF YEAR	**$1,524,630**	**$1,935,320**	**$2,439,775**	**$2,394,015**	**$45,760**	**$2,842,537**	**$402,762**	**16.5**
AVERAGE INTEREST RATE (END OF YEAR)	3.76%	3.85%	4.03%	4.09%		4.47%		
SUBORDINATED								
BALANCE - BEGINNING OF YEAR	$229,775	$229,775	$227,225	$227,225	$0	$134,745	($92,480)	(40.7)
MATURITIES / RETIREMENTS	0	(2,550)	(92,480)	(2,555)	(89,925)	(2,560)	89,920	(97.2)
NEW ISSUES	0	0	0	0	0	0	0	0.0
BALANCE - END OF YEAR	**$229,775**	**$227,225**	**$134,745**	**$224,670**	**($89,925)**	**$132,185**	**($2,560)**	**(1.9)**
AVERAGE INTEREST RATE (END OF YEAR)	4.24%	4.23%	4.24%	4.22%		4.01%		
MINIBONDS								
BALANCE - BEGINNING OF YEAR	$31,737	$0	$0	$0	$0	$0	$0	0.0
MATURITIES / RETIREMENTS	(32,344)	0	0	0	0	0	0	0.0
ACCRETED INTEREST	607	0	0	0	0	0	0	0.0
BALANCE - END OF YEAR	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**0.0**
AVERAGE INTEREST RATE (END OF YEAR)								
COMMERCIAL PAPER								
BALANCE - BEGINNING OF YEAR	$250,000	$325,000	$250,000	$250,000	$0	$250,000	$0	0.0
MATURITIES / RETIREMENTS	0	(75,000)	(100,000)	0	(100,000)	0	100,000	(100.0)
NEW ISSUES	75,000	0	100,000	0	100,000	0	(100,000)	(100.0)
BALANCE - END OF YEAR	**$325,000**	**$250,000**	**$250,000**	**$250,000**	**$0**	**$250,000**	**$0**	**0.0**
AVERAGE INTEREST RATE (END OF YEAR)	0.16%	1.50%	3.17%	3.50%		4.00%		
SEPARATE SYSTEM REVENUE BONDS (NC2)								
BALANCE - BEGINNING OF YEAR	$205,150	$201,495	$197,680	$197,680	$0	$193,680	($4,000)	(2.0)
MATURITIES / RETIREMENTS	(3,655)	(3,815)	(4,000)	(4,000)	0	(4,200)	(200)	5.0
NEW ISSUES	0	0	0	0	0	0	0	0.0
BALANCE - END OF YEAR	**$201,495**	**$197,680**	**$193,680**	**$193,680**	**$0**	**$189,480**	**($4,200)**	**(2.2)**
AVERAGE INTEREST RATE (END OF YEAR)	4.95%	4.95%	4.95%	4.95%		4.95%		
TOTAL AVERAGE INTEREST RATE (END OF YEAR)	3.45%	3.74%	4.21%	4.10%		4.44%		
TOTAL INTEREST EXPENSE (ON DEBT)	$68,537	$84,832	$106,969	$111,560	($4,591)	$136,654	$29,685	27.8
DEBT TO CAPITALIZATION RATIO	61%	64%	65%	67%		66%		

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

Financial Statements

Cash Flow Analysis

2023 Projection Compared to 2023 Budget

Cash Receipts

2023 projected cash receipts are $1,476.1 million, which is $40.7 million over budget. Total cash receipts were impacted by elevated wholesale revenues and investment income. Wholesale revenues were impacted by elevated congestion hedging revenues. Investment income performance was due to higher cash balances and higher average earnings rates.

Cash Disbursements

2023 cash disbursements are projected to be $1,952.8 million or $58.4 million over budget. Disbursements are over budget primarily due to an unplanned pension contribution as well as extended outages contributing to higher purchased power, partially offset by decreased decommissioning funding.

2024 Budget Compared to 2023 Projection

Cash Receipts

2024 cash receipts are budgeted to increase by $16.8 million to $1,492.9 million. This increase is primarily due to increased retail revenue from projected load growth and the general rate increase to retail customers, partially offset by decreased wholesale revenues as congestion hedging revenues are anticipated to decrease significantly from 2023 levels.

Cash Disbursements

2024 cash disbursements are budgeted to increase by $77.2 million to $2,029.9 million. Increases in cash disbursements primarily relate to capital expenditures and increased debt service to support the capital portfolio. Partially offsetting is decreased purchased power and production expense as unit availability returns to normal levels. Decommissioning funding is also expected to decrease due to discontinuing contributions as the decommissioning trust is fully funded.

The budgeted values of cash receipts and disbursements result in a projected year-end cash balance of $529.0 million in 2024.

CASH FLOW ANALYSIS
(DOLLARS IN THOUSANDS)

Cash Flow Analysis

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
CASH BEGINNING OF PERIOD	$366,157	$636,681	$667,880	$620,910	$46,970	$642,041	($25,839)	(3.9)
RECEIPTS								
RETAIL REVENUES	$1,034,029	$1,126,285	$1,161,913	$1,160,884	$1,029	$1,222,054	$60,142	5.2
WHOLESALE REVENUES (INCL. NC2)	310,228	248,490	218,371	201,247	17,123	168,881	(49,489)	(22.7)
OTHER ELECTRIC REVENUES	37,637	42,940	43,789	39,679	4,110	42,234	(1,555)	(3.6)
INTEREST INCOME	37,107	50,004	48,915	30,152	18,764	57,211	8,296	17.0
PRODUCTS & SERVICES	1,830	2,086	3,092	3,400	(308)	2,484	(609)	(19.7)
TOTAL RECEIPTS	$1,420,830	$1,469,805	$1,476,080	$1,435,362	$40,719	$1,492,865	$16,785	1.1
DISBURSEMENTS								
O&M EXPENSE (W/O FUEL & PURCHASED POWER)	$472,243	$409,119	$558,113	$491,668	$66,445	$540,396	($17,717)	(3.2)
DECOMMISSIONING EXPENSE	132,543	141,918	34,702	95,168	(60,466)	15,298	(19,404)	(55.9)
PAYMENTS IN LIEU OF TAXES	38,555	38,605	40,226	40,540	(314)	42,882	2,656	6.6
DEBT SERVICE	116,972	146,457	170,260	164,486	5,774	215,568	45,308	26.6
CAPITAL EXPENDITURES	281,122	551,032	652,100	640,000	12,100	727,000	74,900	11.5
FUEL	203,944	188,414	161,805	165,934	(4,129)	178,358	16,554	10.2
PURCHASED POWER	395,399	357,276	335,546	296,525	39,021	310,416	(25,130)	(7.5)
CHANGES IN OTHER NET ASSETS	15,476	(17,420)	0	0	0	0	0	0.0
TOTAL DISBURSEMENTS	$1,656,254	$1,815,401	$1,952,752	$1,894,321	$58,430	$2,029,918	$77,166	4.0
NET OPERATING CASH FLOW	($235,424)	($345,596)	($476,671)	($458,959)	($17,712)	($537,053)	($60,382)	12.7
FINANCING	$531,245	$474,385	$578,398	$504,000	$74,398	$448,657	($129,741)	(22.4)
FINANCING COST / RESERVE AMOUNT	(25,297)	(22,590)	(37,641)	(25,060)	(12,581)	(24,676)	12,965	(34.4)
COMMERCIAL PAPER - NET	0	(75,000)	0	0	0	0	0	0.0
OTHER	0	0	(89,925)	0	(89,925)	0	89,925	(100.0)
TOTAL FINANCING	$505,948	$376,795	$450,832	$478,940	($28,108)	$423,981	($26,851)	(6.0)
TOTAL CHANGE IN CASH	$270,524	$31,199	($25,839)	$19,981	($45,820)	($113,072)	($87,232)	337.6
CASH END OF PERIOD	$636,681	$667,880	$642,041	$640,890	$1,150	$528,969	($113,073)	(17.6)
DECOMMISSIONING FUND	$519,702	$534,901	$447,190	$591,073	($143,883)	$346,768	($100,422)	(22.5)

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

Omaha Public Power District

Energy Sales

Energy Sales

Electric Energy Sales & Electric Customers

Retail energy sales are budgeted to be 13,648,443 MWh or 9.5% greater than 2023 projections, driven by load growth across all customer classes, especially industrial customers. Wholesale energy sales (including NC2 participation sales) are budgeted to increase by 533,805 MWh or 16.6% from 2023 projected levels. Total electric energy sales are budgeted to be 17,398,684 MWh or 10.9% more than the 2023 projected energy sales due increased retail sales across all customer classes, particularly in the industrial class.

In 2024, the average number of retail customers is budgeted to increase by 4,350 or 1.1% above 2023 projections.

ELECTRIC ENERGY SALES AND CUSTOMERS

Energy Sales and Customers

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. MWh CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
ELECTRIC ENERGY SALES (MWh)								
RESIDENTIAL	3,868,322	3,937,046	3,944,441	3,841,839	102,602	3,995,295	50,854	1.3
COMMERCIAL	3,668,742	3,763,330	3,820,359	3,839,630	(19,271)	3,891,422	71,063	1.9
INDUSTRIAL	4,014,243	4,293,784	4,738,220	5,286,601	(548,381)	5,703,474	965,254	20.4
UNBILLED SALES	(43,517)	111,815	(35,808)	5,785	(41,593)	58,252	94,060	(262.7)
RETAIL ENERGY SALES	11,507,790	12,105,976	12,467,212	12,973,856	(506,644)	13,648,443	1,181,231	9.5
NC2 PARTICIPANT	1,937,894	1,867,157	1,740,794	2,024,921	(284,127)	2,096,963	356,169	20.5
OTHER	2,284,818	2,543,536	1,475,641	1,629,690	(154,049)	1,653,278	177,636	12.0
WHOLESALE ENERGY SALES	4,222,712	4,410,693	3,216,435	3,654,611	(438,176)	3,750,240	533,805	16.6
TOTAL MWh SALES	15,730,502	16,516,668	15,683,648	16,628,467	(944,819)	17,398,684	1,715,036	10.9
ELECTRIC CUSTOMERS (12 MONTH AVG.)								
RESIDENTIAL	346,503	351,712	357,393	355,847	1,546	361,464	4,071	1.1
COMMERCIAL	48,781	49,550	49,720	49,689	31	49,987	267	0.5
INDUSTRIAL	141	135	137	145	(8)	149	12	8.8
TOTAL RETAIL CUSTOMERS	395,425	401,397	407,250	405,681	1,569	411,600	4,350	1.1
kWh / CUSTOMER								
RESIDENTIAL	11,164	11,194	11,037	10,796	240	11,053	16	0.1
COMMERCIAL	75,209	75,950	76,837	77,273	(436)	77,849	1,011	1.3
INDUSTRIAL	28,537,271	31,805,809	34,585,550	36,459,317	(1,873,767)	38,278,351	3,692,801	10.7
AVERAGE kWh / CUSTOMER	29,212	29,881	30,701	31,966	(1,265)	33,018	2,317	7.5

NOTES: 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 2023 are projected to be $1,409.3 million, which is $8.1 million or less than 0.1% over the 2023 budget. Electric operating revenues are at budget due to offsetting impacts of wholesale revenues and retail revenues. Wholesale revenues are $10.2 million over budget for 2023 primarily due to elevated congestion hedging revenues. Retail revenues are $6.3 million under budget for 2023 largely due to delayed load ramp from industrial customers.

Total electric operating revenues for 2024 are budgeted to be $1,432.4 million, which is $23.0 million or 1.6% above the 2023 projected operating revenues. Retail revenues are $67.5 million greater than 2023 projection due to load growth across all customer classes, especially industrial customers, partially offset by a contribution to the Decommissioning and Benefits Reserve Account (DBRA). Wholesale revenues are $42.7 million below the 2023 projected amount primarily due to decreased congestion hedging revenue and retail load growth outpacing owned generation.

OPERATING REVENUES
(DOLLARS IN THOUSANDS)

Operating Revenues

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
ELECTRIC OPERATING REVENUES								
RESIDENTIAL	$439,609	$460,848	$476,115	$463,690	$12,425	$490,025	$13,910	2.9
COMMERCIAL	324,790	336,360	351,970	353,539	(1,569)	378,580	26,610	7.6
INDUSTRIAL	276,265	291,343	318,255	351,251	(32,996)	363,789	45,534	14.3
FPPA RECEIVABLE AMORTIZATION	7,616	7,400	(7,400)	(7,400)	(0)	0	7,400	(100.0)
PROVISION FOR DBRA	83,000	(6,000)	19,781	0	19,781	(11,939)	(31,720)	(160.4)
UNBILLED REVENUES/ADJUSTMENTS	(372)	10,556	(550)	3,396	(3,947)	5,185	5,735	(1,042.0)
TOTAL RETAIL SALES	$1,130,907	$1,100,507	$1,158,171	$1,164,477	($6,307)	$1,225,640	$67,470	5.8
NC2 PARTICIPANTS	$70,248	$69,086	$68,684	$69,393	($709)	$63,554	($5,130)	(7.5)
OTHER	258,128	187,392	138,536	127,671	10,864	100,930	(37,606)	(27.1)
TOTAL WHOLESALE REVENUES	$328,376	$256,478	$207,220	$197,064	$10,156	$164,484	($42,736)	(20.6)
TOTAL SALES OF ELECTRIC ENERGY	$1,459,283	$1,356,985	$1,365,391	$1,361,541	$3,849	$1,390,125	$24,734	1.8
OTHER ELECTRIC REVENUES	$37,637	$43,799	$43,918	$39,679	$4,239	$42,233	($1,685)	(3.8)
TOTAL ELECTRIC OPERATING REVENUES	$1,496,920	$1,400,784	$1,409,309	$1,401,221	$8,088	$1,432,358	$23,049	1.6

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

Energy Sales

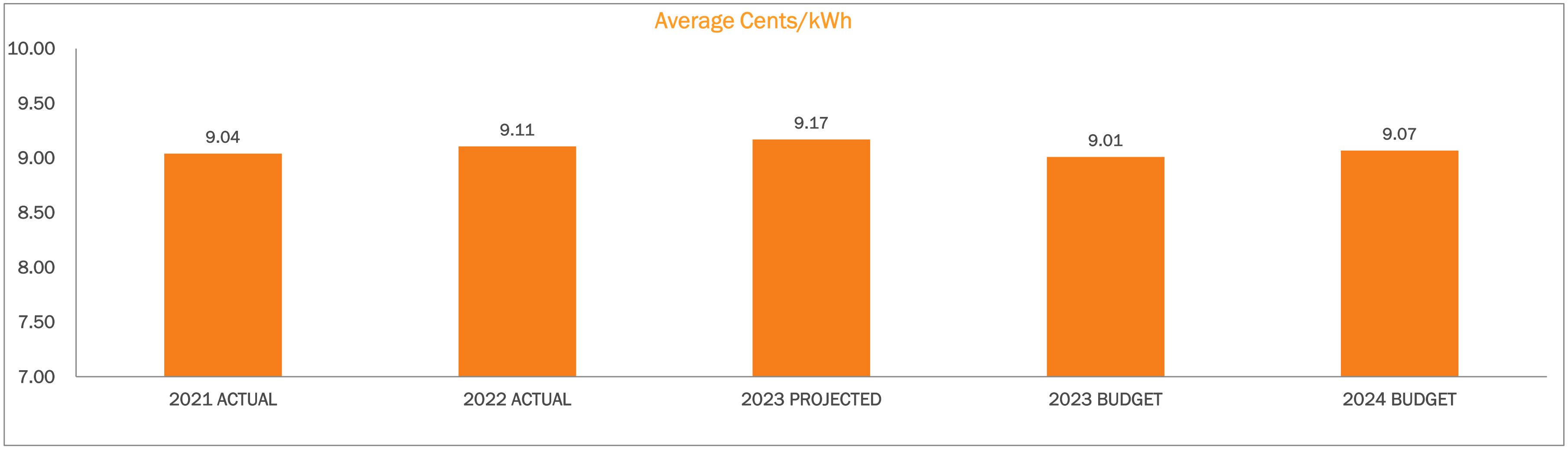
Average Cents/kWh

The 2023 average price per kWh for retail customers is projected to be 9.17 cents, which is 0.16 cents more than budget. The primary driver is due to higher than expected wholesale market energy prices, which is a component of the rate for the Large Power Transmission Level - Market Rate, Rate 261M. Consequently, the price per kWh variance is not the result of a rate change, rather, the result of the impacts of market prices and actual billings for our market rate offering.

The 2024 average price per kWh for retail customers is budgeted to be 9.07 cents. This is 0.10 cents, or a 1.1% decrease, from the 2023 projected amount. Both the residential and commercial classes will experience a modest increase mirroring the assumed retail rate adjustment. The industrial class is experiencing a slight decrease in average price per kWh as high load factor customers represent an increasing proportion of overall industrial load.

AVERAGE CENTS/kWh

Average Cents/kWh	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	% CHANGE
RESIDENTIAL	11.38	11.73	12.07	12.07	0.00	12.27	0.20	1.6
COMMERCIAL	8.86	8.95	9.21	9.21	0.00	9.73	0.52	5.6
INDUSTRIAL	6.97	6.88	6.72	6.64	0.08	6.38	(0.34)	(5.1)
RETAIL AVERAGE *	9.04	9.11	9.17	9.01	0.16	9.07	(0.10)	(1.1)



NOTES: 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 2024 are budgeted to be 14,365,568 MWh, an increase of 10.6% from the 2023 projected amount. The major components of net system requirements are below by sales and supply components.

Total sales are budgeted to increase 1,715,036 MWh or 10.9% from the 2023 projected amount. Retail sales are budgeted to increase 1,181,231 MWh from the 2023 projected amount. Wholesale energy sales, excluding NC2 participation sales, are budgeted to increase by 177,636 MWh or 12.0% from the 2023 projected amount.

Net generation is budgeted to increase 24.8% in 2024 to 10,147,180 MWh and firm/participation purchases are budgeted to increase 8.0% from the 2023 projected amount. Wholesale purchases are budgeted to decrease 410,917 MWh from the 2023 projected amount primarily due to fewer planned and unplanned outages. The increase in 2024 budgeted MWh sales for NC2 participation sales reflect longer than expected planned and unplanned outages of NC2 in 2023, but are commensurate with historic MWh sales.

Net System Requirements
Sales and Supply Components (MWh)

	PROJECTED 2023	BUDGET 2024	INCREASE / (DECREASE)	% CHANGE
Sales Components				
Retail Sales	12,467,212	13,648,443	1,181,231	9.5
NC2 Participation Sales	1,740,794	2,096,963	356,169	20.5
Wholesale Energy Sales	1,475,641	1,653,278	177,636	12.0
Total	15,683,648	17,398,684	1,715,036	10.9
Supply Components				
Net Generation	8,130,414	10,147,180	2,016,765	24.8
Firm/Participation Purchases	3,849,978	4,158,744	308,767	8.0
Wholesale Purchases	4,220,801	3,809,884	(410,917)	(9.7)
Lost or Unaccounted For	(517,546)	(717,124)	(199,579)	38.6
Total	15,683,648	17,398,684	1,715,036	10.9

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

NET SYSTEM REQUIREMENTS

Net System Requirements

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. MWh CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
NET GENERATION (MWh)								
TOTAL NET GENERATION	9,008,256	9,335,878	8,130,414	10,031,682	(1,901,267)	10,147,180	2,016,765	24.8
FIRM/PARTICIPATION PURCHASES	4,070,852	4,473,672	3,849,978	3,962,377	(112,399)	4,158,744	308,767	8.0
WHOLESALE PURCHASES	3,139,174	3,198,414	4,220,801	3,373,165	847,636	3,809,884	(410,917)	(9.7)
TOTAL PURCHASES	7,210,026	7,672,086	8,070,779	7,335,542	735,237	7,968,628	(102,151)	(1.3)
TOTAL INPUT	16,218,282	17,007,963	16,201,193	17,367,224	(1,166,030)	18,115,808	1,914,615	11.8
WHOLESALE ENERGY SALES								
NC2 PARTICIPANT	1,937,894	1,867,157	1,740,794	2,024,921	(284,127)	2,096,963	356,169	20.5
OTHER	2,284,818	2,543,536	1,475,641	1,629,690	(154,049)	1,653,278	177,636	12.0
TOTAL WHOLESALE ENERGY SALES	4,222,712	4,410,693	3,216,435	3,654,611	(438,176)	3,750,240	533,805	16.6
NET SYSTEM REQUIREMENTS	11,995,569	12,597,271	12,984,758	13,712,613	(727,855)	14,365,568	1,380,810	10.6
TOTAL RETAIL SALES	11,507,790	12,105,976	12,467,212	12,973,856	(506,644)	13,648,443	1,181,231	9.5
ENERGY LOST OR UNACCOUNTED FOR	487,780	491,295	517,546	738,757	(221,211)	717,124	199,579	38.6
TOTAL RETAIL SALES	11,995,569	12,597,271	12,984,758	13,712,613	(727,855)	14,365,568	1,380,810	10.6

PEAK LOAD (MW)								
PEAK LOAD EXCLUDING DEMAND RESPONSE	2,633	2,680	2,906	2,817	89	3,009	103	3.5
DEMAND RESPONSE*	124	126	127	134	(7)	140	13	10.2
PEAK LOAD INCLUDING DEMAND RESPONSE	2,509	2,554	2,779	2,683	96	2,869	90	3.2
LOAD FACTOR (%) - REFLECTS DEMAND RESPONSE	54.6	56.3	53.3	56.8	(3.5)	57.2	3.8	7.2

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

* Does not include voluntary demand response

Operations, Maintenance, and Decommissioning Expenses

Operations, Maintenance, and Decommissioning Expenses

The District's 2024 total budgeted operations and maintenance (O&M) expense is $1,021.0 million, which is $0.6 million or 0.1% lower than the 2023 projected amount. 2023 O&M has been greatly impacted by extended unplanned outages, driving up purchased power and production expenses, but causing savings in fuel expense. In addition, 2023 administrative and general expenses are elevated primarily due to an unplanned pension contribution.

2024 Budget Compared to 2023 Budget

Fuel expense is budgeted at $180.2 million, an increase of $14.9 million or 9.0% more than the 2023 budgeted amount primarily due to new generation from Power with Purpose projects.

Production expense is budgeted to be $147.7 million, which is $15.8 million or 12.0% above the 2023 budgeted amount. The primary driver is additional outage costs as well as additional headcount and expense to support the new generation that will be operational in 2024.

Purchased power, including wind purchases, represents 30.6% of total O&M expense and is budgeted at $312.5 million. This represents an increase of $15.0 million or 5.0% above the 2023 budget amount. The increase from the 2023 budget is primarily due to anticipated customer load growth, which outpaces owned generation.

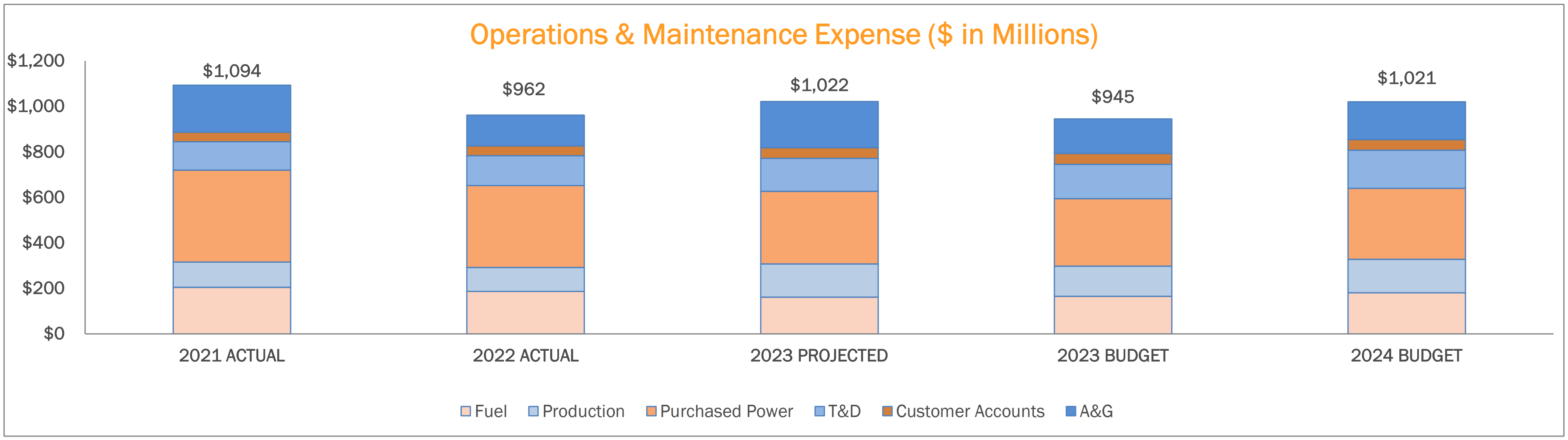
Transmission and distribution expense is budgeted at $166.6 million, which is $16.2 million or 10.7% more than the 2023 budgeted amount. The increase over the budget amount is due to additional cable locates as well as increased headcount and outside services in support of enterprise priorities such as Resource Adequacy and Two-Way Communication (AMI).

Administrative and general expense is budgeted at $166.9 million. This category reflects an increase of $15.3 million or 10.1% more than the 2023 budget. The increase in 2024 is primarily related to the increased headcount and benefit costs in support of a growing utility and expenses related to supporting enterprise priorities, such as Master Facilities Plan and Technology Transformation.

Decommissioning expense represents the annual funding of the decommissioning liability. Decommissioning funding for 2024 is budgeted to be $15.3 million, which is $79.9 million less than the 2023 budget due to the decommissioning trust being fully funded. Contributions to decommissioning represent investment earnings on balances in the decommissioning trust.

OPERATIONS, MAINTENANCE, AND DECOMMISSIONING EXPENSES
(DOLLARS IN THOUSANDS)

Operations, Maintenance, and Decommissioning Expenses	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
FUEL	$203,944	$186,359	$161,635	$165,301	($3,666)	$180,164	$18,529	11.5
PRODUCTION	111,332	105,534	145,595	131,925	13,670	147,748	2,153	1.5
PURCHASED POWER	404,426	360,420	318,999	297,566	21,433	312,527	(6,472)	(2.0)
TRANSMISSION AND DISTRIBUTION	125,305	130,856	145,835	150,401	(4,566)	166,553	20,718	14.2
CUSTOMER	41,175	43,887	46,101	47,881	(1,780)	47,096	995	2.2
ADMINISTRATIVE AND GENERAL	207,410	135,402	203,422	151,593	51,829	166,938	(36,484)	(17.9)
TOTAL O&M EXPENSE	$1,093,592	$962,458	$1,021,587	$944,666	$76,921	$1,021,028	($559)	(0.1)
DECOMMISSIONING EXPENSE	$132,543	$141,918	$34,703	$95,168	($60,465)	$15,298	($19,405)	(55.9)



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

Omaha Public Power District

Capital Expenditure Plan

Capital Expenditure Plan

Capital Expenditures

The 2024 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, Two-way Communication (AMI) and the Master Facilities Plan

Capital expenditures represent 34.5% of the total 2024 budget. Capital expenditures are budgeted at $727.0 million, which is $75.6 million more than the 2023 projection and $87.0 million more than the 2023 budget.

The year over year growth is related to both investments in District expansion and enterprise priorities, as well as increased investment in existing assets. Expand and enterprise priority projects are budgeted at $508.8 million, an increase of $56.0 million from the 2023 budget of $452.8 million. As the District's asset base grows, additional investment is required on existing infrastructure. The 2024 budget includes $218.2 million for projects that maintain and improve existing assets, which is an increase of $31.0 million from the 2023 budget.

Production Plant decreased to $261.3 million from the 2023 projected spend of $304.1 million. The decrease is primarily related to spending on the Power with Purpose projects decreasing as the project nears completion in 2024. The year over year decrease is partially offset by investments to support the Near Term Generation projects which were a result of a 2023 resolution.

Transmission and Distribution is budgeted at $356.2 million, an increase of $91.7 million from the 2023 projection. The increase represents the investments to support a growing community and utility and are aligned with the District's Near Term Generation, Power with Purpose, and Two-way Communication (AMI) efforts.

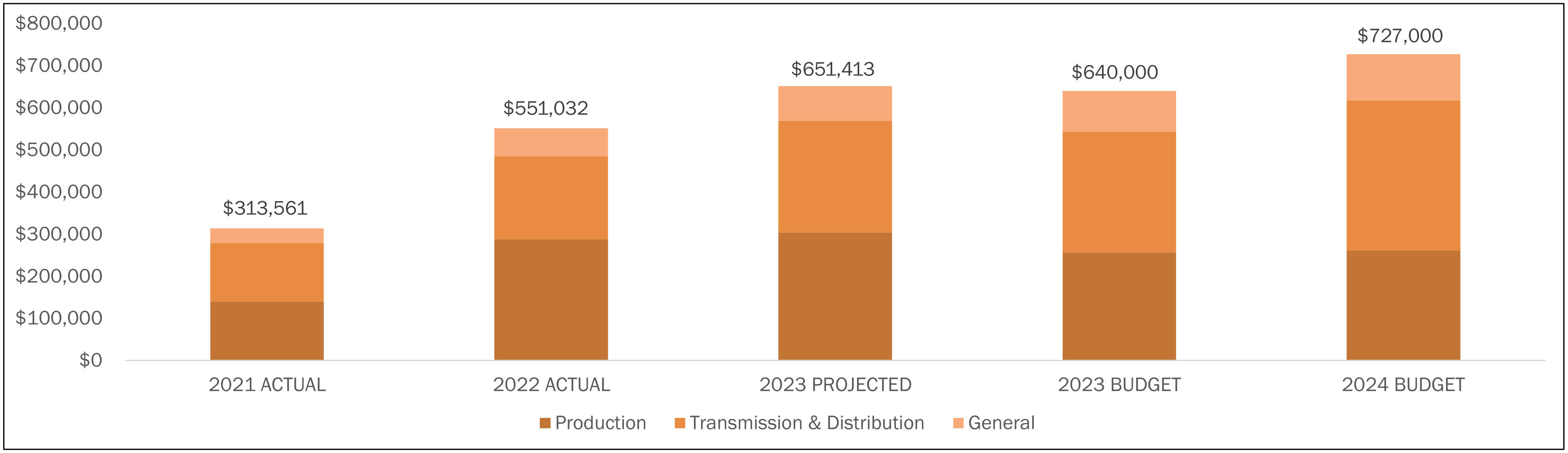
General Plant for 2024 is budgeted to be $109.6 million, which is $26.7 million or 32.2% higher than the 2023 projected expenditures, driven by business technology and facilities investments and upgrades, which are aligned with the District's enterprise priorities.

CAPITAL EXPENDITURES
(DOLLARS IN THOUSANDS)

Capital Expenditures

	ACTUAL 2021	ACTUAL 2022	PROJECTED 2023	BUDGET 2023	VARIANCE 2023	BUDGET 2024	24 BUDGET VS. 23 PROJ. $ CHANGE	24 BUDGET VS. 23 PROJ. % CHANGE
PRODUCTION	$139,240	$287,260	$304,082	$256,347	$47,735	$261,259	(42,823)	(14.1)
TRANSMISSION AND DISTRIBUTION	139,475	197,344	264,433	286,871	(22,438)	356,176	91,743	34.7
GENERAL	34,846	66,428	82,898	96,782	(13,884)	109,565	26,667	32.2
TOTAL	$313,561	$551,032	$651,413	$640,000	$11,413	$727,000	$75,587	11.6

NOTES: 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:	2021 Expenditures	2022 Expenditures	2023 Projection	2024 Budget
Near Term Generation Support generation and transmission & distribution for Board Resolution No. 6582 approved on August 15, 2023	$0	$0	$3,810	$149,022
Power with Purpose Support generation and transmission & distribution for Board Resolution No. 6351 approved on November 14, 2019	$110,752	$291,851	$286,000	$86,965
Master Facilities Plan Investment and upgrades to various OPPD facilities, which are all over 30 years old with only minor enhancements throughout their life	$997	$16,575	$21,428	$67,676
Circuit and Substation Upgrades Upgrade and replace multiple circuits and substations due to the expansion of our transmission and distribution infrastructure	$14,160	$27,601	$48,723	$53,862
AMI - Smart Grid Technology to support AMI	$0	$2,347	$8,310	$32,404
Transformer Purchases and Replacements Procure transformers to replace aging equipment and support load growth	$10,087	$15,509	$22,599	$28,060

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

RECOMMENDED PROJECTS:	2021 Expenditures	2022 Expenditures	2023 Projection	2024 Budget
Customer Service Residential Project Purchase and installation of underground or overhead infrastructure to new residential developments	$10,438	$14,012	$17,837	$18,934
North Omaha Station Conversion Supports continued operation of North Omaha station	$436	$4,605	$15,400	$17,040
Arbor Railroad Line Improvements Relocation of OPPD transmission and distribution facilities that are located in public road right-of-way	$0	$0	$6,539	$15,201
Transportation Fleet Replacement Routine replacement of OPPD-owned transportation equipment, including light, medium and heavy duty trucks and construction equipment	$4,891	$7,113	$16,361	$14,677
Transmission and Distribution Street & Highway Project Relocation of OPPD transmission and distribution facilities that are located in public road right-of-way	$10,006	$12,108	$11,533	$12,000
Customer Service Commercial and Industrial Projects Purchase and installation of underground or overhead infrastructure for commercial and industrial customers	$9,287	$9,775	$12,069	$11,745

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

RECOMMENDED PROJECTS:	2021 Expenditures	2022 Expenditures	2023 Projection	2024 Budget
Transmission Distribution Improvement Program-Cable Replacement Replace the worst performing underground distribution cable on a performance driven basis	$10,117	$11,264	$13,546	$11,298
Substations and Control Centers Security Upgrades Security modifications required to address identified threats and vulnerabilities at various substation and control centers	$1,455	$1,439	$7,797	$11,241
Geographic Information System (GIS) Create centralized geospatial platform to support many functions at OPPD	$0	$0	$0	$10,254
Nebraska City Unit 1 Air Preheater Baskets Replacement Replace of baskets and seals in both NC1 air preheaters during a scheduled maintenance outage	$0	$0	$284	$7,854
Ground Line Inspection and Treatment Pole Replacement Replace degraded wood poles and structures used for transmission and distribution	$8,150	$8,810	$9,031	$7,255
Downtown Fiber Redesign Relocate OPPD fiber network	$0	$0	$105	$5,911

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

RECOMMENDED PROJECTS:	2021 Expenditures	2022 Expenditures	2023 Projection	2024 Budget
Energy Marketing Trade System OPPD will migrate the Energy Marketing and Trading processes to an industry standard	$0	$0	$0	$5,323
Software Renewals Renew subscription based software used by the district to conduct business	$1,262	$2,968	$11,859	$5,138
Nebraska City 1 Intake Structure Environmental Upgrade Replace existing traveling screens (circulating water intake structure) at Nebraska City Fossil location for renewal of the environmental permit	$0	$100	$1,428	$5,127
Microwave Network Upgrades Upgrade outdated microwave network	$0	$0	$0	$5,005
Transmission Distribution Improvement Program-Conductors Replace conductors on a performance driven basis	$2,227	$4,230	$5,750	$4,893

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

RECOMMENDED PROJECTS:	2021 Expenditures	2022 Expenditures	2023 Projection	2024 Budget
Nebraska City Landfill Purchase new landfill to transition to after the current landfill reaches capacity	$18	$106	$5,115	$4,144
Partnership Solar OPPD will be developing partnerships with our commercial and agricultural customers to build solar PV products on rooftops and in corners of farm fields.	$0	$0	$0	$4,110

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 2024 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 2024.

In performing our review, we evaluated the 2024 COP for consistency with prudent utility practices and the reasonableness of the budget estimates established. In addition, we reviewed the 2024 Corporate Operating Plan and associated presentations, which provided further details on many of the Operating Plan's major components. The primary presentation topics ranged from load forecasting, fuel planning, and employee benefits to budgetary and financial matters, which we will first discuss individually, followed by a summary of the entire Operating Plan:

Energy Delivery – The Energy Delivery plan outlines the 2024 utility operations and maintenance (O&M) and capital budgets. The O&M budget is allocated across the following divisions: Transmission and Distribution, Asset Management, Integrated Work Management, and Substation Protection. The capital budget is divided into Core, Mandatory, Critical, Value-Add, and Enterprise Priority categories. In addition, the District provided further stratification of the Capital and O&M budget across multiple classification themes. O&M and capital expenses are forecasted through 2025.

The Energy Delivery Plan 2024 budget ($273 million) is lower than the 2023 projection ($355 million). Moreover, we note that O&M expenses are higher in 2024 compared to 2023 by 6%, while the capital expenses are lower by 31%. The higher capital expense budget of 2023 was driven primarily by Power with Purpose projects that will decrease as the project nears completion in 2024.

Integrated Resource Plan – The integrated resource plan is prepared every five years as part of the District's contractual commitment to the Western Area Power Administration (WAPA). It provides the optimum resource expansion plan to meet the District's forecasted demand and energy requirements. The information provided by the District included forecasted coal and natural gas generation through 2028 and 2023 system sales and purchases. It also forecasted Southwest Power Pool (SPP) north hub prices, the District's total purchased power, and the District's total off-system sales out to 2028. The District also outlined its Power with Purpose and near-term generation plan. This plan describes its commitment to retire its coal-fired North Omaha Station but preserve system reliability by adding utility-scale solar and reciprocal internal combustion engines (RICE) and natural gas-fired combustion turbines (CTs). As part of the Power with Purpose plan, the District will add around 1,800 MWs of renewables, with more than 750 MW of utility-scale solar. The District will also add 750 MW of natural gas-fired units by 2030.

The District's assumptions in developing the integrated resources plan reflect a thoughtful and reasonable approach considering the transitioning electricity utility industry. 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 Brattle team finds the District's forecast of power prices in their 2024 Corporate Operating Plan reasonable and its demand response programs robust.

Fuel Plan – The fuel plan projects the District's coal, natural gas, and oil fuel costs from 2024 through 2028. These projections are based on system generation projections from 2024 through 2028 (including onboarding of solar to the system and retirements of thermal units), per-unit expenses, and fuel inventory targets.

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. The project inventories of fossil fuels are appropriate given the requirements of the District and general industry practices. 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.

Energy Production Capital Budget – The Energy Production Capital Budget has two components: a sustain 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 $337 million, roughly $78 million higher than the 2023 budget. The primary driver of this increased capital expenditure is the year-over-year growth observed and expected in the District. Expansion projects are budgeted at $246 million, an increase of $32.0 million from the 2023 budget. Sustain projects represent $91 million of the budget.

The plans outlined in the Energy Production Capital Budget appear reasonable given the District's near-and long-term goals. The budget breakdown described in this slide deck acknowledges the need for maintenance while supporting anticipated projects and initiatives.

Energy Production O&M Budget – The District's energy production forecast projects O&M (excluding fuel) expenses and employee headcount for 2024 and 2025. The 2024 expenses are grouped by location and separately by resource. Information on planned outage costs is also provided. Direct O&M expenses are forecasted to increase from around $100 M in 2023 (projected) to over $103.6 M in 2024. In addition to the increase in direct O&M expenses, we note that the 2024 budget for Consumables is roughly 20% higher than the 2023 budget. The full-time headcount of employees is anticipated to increase from 355 in 2023 to 385 in 2024.

The Brattle Group finds that the 2024 Energy Production (Production Operations) forecasted O&M expenses and employee headcount values are reasonable. Additionally, the Brattle Group notes that the increase in total planned outage costs for 2024 ($5.7 M of $28.8 M) is less than the planned outage costs increase for 2023 ($12.1 M of $23.1 M). Boiler and turbine-related outage projects are still the main drivers of the outage costs, similar to the previous year's projections.

Load Forecast – The District's load forecast projects the District's residential, industrial, and commercial energy consumption (load) and system peak demand from 2024 through 2030. Net system load is forecasted to increase from 13 TWh in 2023 to 14 TWh. The load forecast's uses include estimating revenues, dispatch modeling, energy trading/hedging, and future system planning. In addition, the future year's forecasted energy sales are compared against historical data to examine model accuracy, and historical energy consumption and system peak demand are compared to forecasted values.

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 must remain aware of how potential interest rate increases and inflation may impact its economic growth. Given these external economic factors, projected rate increases based on the District's assumed economic conditions may not be sufficient to fund future programs. The District should continue to observe these economic indicators.

Fort Calhoun Decommissioning – The decommissioning deck outlines the timeline and path toward decommissioning, focusing on 2023 goals and accomplishments. The timeline forecasts substantial work to be completed by 2027. The 2024 goals are to complete the reactor vessel segmentation, remove large components, survey and backfill deconstruction area structures, and continue radiological surveys to support the final site release. The process can be monitored using performance metrics (deconstruction cost estimates, fiscal performance, waste pounds removed, radiation safety, percentage completion, and critical milestone success).

Based on the reported metrics, the decommissioning timeline and process appear practical and on target. The District met the majority of the 2023 goals. Brattle's review of the decommissioning is high-level and performed without a detailed analysis.

Safety & Facilities – The Master Facilities Plan, the most significant part of the District's Safety and Facilities budget, outlines plans for several multi-year projects that assume significant consumption of future capital investment, particularly strategic investments within the 2024 Capital Portfolio. By implementing this plan, the District aims to optimize its space utilization and facility location while pursuing net zero carbon production by 2050, increasing customer satisfaction and employee retention.

Technology & Security – The Technology and Security deck outlines the District's current initiatives and five-year Technology and Security goals. Some five-year targets included in the Business Capability 2021-2025 Roadmap are modernizing customer communications, maximizing asset value, increasing real-time energy market awareness with advanced trading analytics, accelerating the flow of information, and maintaining long-term assets. The capital portfolio will experience a 75% increase in 2024 ($87.9 M) compared to the 2023 budget ($50.1 M). Enterprise Priority represents 69% of this portfolio and includes two-way communication and engagement, technology transformation and investment priorities, and subscription-based information technology arrangements (SBITAs).

Additionally, the District plans to deploy advanced metering infrastructure (AMI) meters to all its customers to understand better when customers experience outages and increase the speed of resources deployed to rectify such situations. The District has a plan to deploy 10,000 AMI meters initially. The resulting influx of information has prompted District investment in a system-wide information technology modernization.

The concerns and efforts about metering modernization are pertinent and well-advised. However, an influx of big data can potentially overwhelm an outdated system. Therefore, the District should accelerate investments associated with managing big data to coincide with the timing of AMI meter deployment.

Summary – The Brattle Group, in its review, finds the District's 2024 Corporate Operating Plan to be generally sound. 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 2024 Corporate Operating Plan provide for accomplishing the District's minimum performance objective for debt service coverage. The 2024 Corporate Plan represents a compilation of PowerPoint decks highlighting the various responsibility areas throughout the District. We understand that the District's senior management has reviewed and approved the 2024 Corporate Operating Plan. However, the Brattle Group has identified the following areas of potential concern: the ability of the District's software systems to handle the impending influx of big data, the District's retirement plan structure, the District's debt, and related economic assumptions.

As the District moves forward with its AMI rollout in 2024, it anticipates that the quantity of big data flowing into its systems will increase dramatically. This rapid increase calls into question the ability of the District's current billing software to handle the influx of big data. Therefore, the Brattle Group recommends thoroughly assessing the District's existing software systems.

Much of the District's two retirement funds, OPEB A and OPEB B, are tied to retiree medical expenses. Under these plans, retirees receive the same benefits as active employees. Additionally, the District projects an 11% loss in 2024. This situation may present an issue for two reasons: 1) Retirees tend to be of 'higher risk' than active employees, and 2) Given current and planned interest rate hikes, the District's assumption could understate the total loss to occur in 2024. The Brattle Group questioned the future of the benefits plans and found it reasonable that the District is continuing to introduce new plans. Based on these concerns, The Brattle Group recommends that the District monitor financial markets to ensure its financial market performance does not significantly deviate from what is assumed in the 2024 Corporate Operating Plan.

During its "Safety and Facilities" presentation, the District disclosed its debt to facilities and technology and its belief that load growth in upcoming years will fund expenditures such as the Master Facilities Plan. Said assumed load growth is based on the assumed economic growth of the District. While the interest from large loads to locate in the District may continue to drive load growth, The Brattle Group's concern is that interest rate hikes and continuing inflation could undermine robust economic growth and future load growth. Thus, The Brattle Group recommends that the District be more cautious about economic growth assumptions.

In conclusion, The Brattle Group has utilized the information the District and others provided to us to generate specific assumptions about future conditions that may arise. While we believe these assumptions to be reasonable and accurate for this annual review, said assumptions remain dependent on future events. Thus, observed conditions may diverge from those predicted. Furthermore, though we believe the sources used to support our analysis to be reliable, The Brattle Group has not independently verified sources. Thus, we cannot offer any assurances concerning it. Therefore, observed results may vary from those projected due to discrepancies between observed conditions and those that The Brattle Group has assumed from information provided by the District or others.

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 28, 2023

Ladies and Gentlemen:

I. Background

The Omaha Public Power District ("the District") proposes an average general rate increase of 3.1% effective January 1, 2024. 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 resetting the fuel and purchase power adjustment ("FPPA") base, reducing it by -0.6%. The combination of the general rate increase and the resetting of the FPPA's base results in an overall impact of increasing average rates by 2.5%.

II. Discussion

We have worked closely with the District on its cost of service study ("COSS"), including reviewing the methodology and associated spreadsheets. The primary purpose of a COSS is to allocate the costs of providing service to different customer classes based on cost causation principles and the costs that each customer class imposes on the system.

The FPPA is a mechanism to reflect the changes in fuel and purchase power costs, which can sometimes be highly volatile. The projected decrease in the FPPA's base reflects OPPD's estimate of future market conditions.

III. Findings

The District follows standard industry practices in developing its COSS, and its proposed rate changes are cost-based. In addition, the range of proposed increases among customer classes maintains rate stability and mitigates impacts on customers. We find the proposed rate changes fair, reasonable, and non-discriminatory.

One Beacon Street, Suite 2600
Boston, MA 02108

MAIN +1.617.864.7900
FAX +1.617.507.0063

WEBSITE brattle.com

In addition, The Brattle Group does not find the District's projections that underlie the FPPA's base resetting unreasonable. Thus, the combined effects of the general rate increase and resetting the FPPA base appear reasonable.

IV. Recommendation

We recommend the Board adopt the COSS's results for ratemaking purposes and the FPPA base resetting.

Respectfully yours,

Philip Q Hanser
The Brattle Group
Principal Emeritus

Sanem Sergici, Ph.D.
The Brattle Group
Principal

Exhibit A
Proposed Rate Adjustments
January 1, 2024

	Proposed Revenue Increase ($ M)	Proposed Percent Increase
	Total	Total
Residential		
Residential	$6.8	1.7%
Conservation (Heat Pump Rate)	$1.1	1.5%
Total Residential	$7.9	1.6%
Commercial		
Irrigation Service	$0.1	3.0%
General Service Non-Demand	$1.6	2.3%
General Service Small Demand	$15.5	5.9%
Total Commercial	$17.2	5.0%
Large Commercial/Industrial		
General Service – Large Demand (over 1,000 kW)	$4.5	4.1%
Large Power – Contract (over 10,000 kW)	$1.1	3.9%
Large Power (over 20,000 kW)	$2.7	3.3%
Large Power – High Voltage Transmission Level – Market Energy	$(4.3)	-3.1%
Total Large Commercial/Industrial	$4.0	1.8%
Lighting		
Dusk-to-Dawn Lighting	$(0.0)	-0.4%
Municipal Service – Street Lighting	$1.2	6.6%
Municipal Service –Traffic Signals and Signs	$0.0	3.4%
Total Lighting	$1.2	5.9%
Municipal Service	$(0.0)	-0.9%
TOTAL*	$30.3	2.5%

* Totals may not add due to rounding.

Exhibit B
Proposed Service Regulations and Schedules Revisions
January 1, 2024

Rate Schedules	Description	Proposed Provision(s)
Definitions	Qualified Generator	Harmonize definition with 100 kW limit for net metering customers and the interconnection agreement provision.
Rate 261	Large Power – High-Voltage Transmission Level	Retire offering effective January 1, 2024. Remove reference to Rate 261 in Rider and Rate offerings.
Rate 350	Municipal Service Street Lighting	Add 5 new streetlight methods: 13, 13L, 76T, 76LT, and 81LT.
Rider 461	Fuel and Purchased Power Adjustment	Update FPPA Base rate to 1.951.
Rider 470A	Activation Fees	Update Non-landlords fee from $24.50 to $22.50. Update landlords fee to from $17.00 to $15.00.
Rider 470I	Tenant Attachment Fee	Update fee from $11.55 to $13.70.

Service Regulations & Schedules

your energy partner®

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)	~~261~~	~~Large Power – High Voltage Transmission Level~~	●	●	●		~~355, 461, 464, 467 (E, H, L, V), 469, 483, 490, 499, 500~~
	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- or 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~~25~~ 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- or three-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.

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

- Rate Schedules No. 115, 231, 232, 245, 250~~, 261~~, and 261M
- Rider Schedules No. 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

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 component.

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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-generated 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 on a Customer's Premises that are dangerous to persons, property or service to others
- Nonpayment by the Customer for amounts due
- Failure by the Customer to provide means of access for obtaining regularly Scheduled readings of the Meter or for testing OPPD's equipment
- Failure by the Customer to protect OPPD's equipment from theft, abuse, or vandalism

- OPPD's actions to prevent fraud or abuse of OPPD property
- Outages caused by third parties or animal interference

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 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 applicable Rate Schedule.

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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.

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

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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 No. 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 No. 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.

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.

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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 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	~~10.25~~10.48 cents/kWh	8.63 cents/kWh
101 - 1,000 kWh	~~10.25~~10.48 cents/kWh	7.46 cents/kWh
1,001+ kWh	~~10.25~~10.48 cents/kWh	~~5.27~~6.90 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 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 cents/kWh	9.02 cents/kWh
101 - 880 kWh	9.36 cents/kWh	7.85 cents/kWh
881+ kWh	9.36 cents/kWh	~~4.84~~5.68 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)	$~~17.94~~21.36	$~~24.06~~27.48

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: $~~179.40~~213.60 for Single-Phase
$~~240.60~~274.80 for Three-Phase

Minimum Annual Connected Load Charge is calculated as the 10 HP minimum annual connected Load charge requirement of $~~179.40~~213.60 for single-phase, or $~~240.60~~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	~~9.78~~9.81 cents/kWh	7.89 cents/kWh
1,001 - 3,000 kWh	~~8.40~~9.81 cents/kWh	7.89 cents/kWh
3,001+ kWh	~~8.40~~9.81 cents/kWh	5.24 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 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	$~~5.38~~7.08

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	~~5.93~~5.92 cents/kWh
All additional kWh	5.81 cents/kWh	~~4.50~~4.56 cents/kWh

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

Minimum Monthly Bill: $~~116.70~~147.30

The minimum monthly bill is calculated as the 18-kilowatt minimum Demand requirements of $~~96.84~~127.44, 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	$~~11.65~~13.35

Minimum Billing Demand of 1,000 kW per month.

Energy Charge:

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

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

Minimum Monthly Bill: $~~11,765.31~~13,465.31

The minimum monthly bill is calculated as the 1,000-kilowatt minimum Demand requirements of $~~11,650~~13,350, 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	$~~13.47~~15.17

Minimum Billing Demand of 10,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	3.97 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: $~~135,165.28~~152,165.28

The minimum monthly bill is calculated as the 10,000-kilowatt minimum Demand requirements of $~~134,700~~151,700 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	$~~13.47~~15.17

Minimum Billing Demand of 20,000 kW per month.

Energy Charge:

Energy Usage	All Months (Jan. 1 – Dec.31)
kWh	3.91 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: $~~269,911.73~~303,911.73

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirements of $~~269,400~~303,400, 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. 261~~

~~Large Power – High Voltage Transmission Level~~

~~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.~~

~~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: $584.53 per month~~
~~plus,~~

~~Demand Charge:~~

~~Billing Demand~~	~~Per kW Month~~
~~Per kW~~	~~$12.66~~

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

~~Energy Charge:~~

~~Energy Usage~~	~~All Months (Jan. 1 – Dec.31)~~
~~kWh~~	~~3.76 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: $253,784.53 for Customers taking service at 161,000 volts~~
~~or~~
~~$2,532,584.53 for Customers taking service at 345,000 volts~~

~~The minimum monthly bill is calculated as the 20,000 kilowatt minimum Demand~~

~~requirement of $253,200 for interconnection at 161,000 volts, or 200,000 kilowatt minimum Demand requirement of $2,532,000 for interconnection at 345,000 volts, plus the monthly service charge of $584.53. 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 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 highest 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 the 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 for 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~~

~~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-owned facilities.~~

~~OPPD will determine the Point(s) of Delivery using the information provided by the Customer regarding the Customer's requirements. Also, 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. 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	$~~19.52~~18.36

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: $~~440,200~~377,200 for Customers taking service at 161,000 volts

or

$~~4,312,000~~3,682,000 for Customers taking service at 345,000 volts

The minimum monthly bill is calculated as the 20,000-kilowatt minimum Demand requirement of $~~430,200~~367,200 for interconnection at 161,000 volts, or 200,000 kilowatt minimum Demand requirement of $~~4,302,000~~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

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-owned 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:

(1) Installations on public or semi-public thoroughfares including public parks, where such installations would conflict with a legally constituted public authority having jurisdiction, and

(2) 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
175	7,000 lumen mercury-vapor light fixture*	$13.70
200	22,000 lumen high-pressure sodium light fixture	$18.69
400	20,000 lumen mercury-vapor light fixture*	$18.69

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
Additional pole installed	$1.38
Additional span of secondary conductors installed	$0.75

**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	N/A	~~$202.84~~ $214.18	~~$246.59~~ $260.37
65**	40	400	~~$304.40~~ $321.42	N/A	~~$366.18~~ $386.65	N/A
66*	30	200	~~$201.60~~ $212.87	N/A	$262.36	~~$323.97~~ $342.08
67*	40	200	$237.98	N/A	$299.76	N/A
68**	30	400	~~$274.59~~ $289.94	N/A	~~$345.27~~ $364.57	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	~~$168.48~~ $177.90	N/A	~~$212.59~~ $224.47	~~$256.34~~ $270.67
65**	40	400	~~$328.53~~ $346.89	N/A	~~$383.09~~ $404.50	~~$481.87~~ $580.02
66*	30	200	$229.76	N/A	$277.37	~~$336.76~~ $355.58
67*	40	200	~~$262.11~~ $276.76	N/A	~~$316.37~~ $334.06	~~$361.49~~ $403.20
68**	30	400	N/A	N/A	~~$358.06~~ $378.08	~~$492.22~~ $519.74

*Restricted

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
61*	25	100	~~$134.83~~ $142.37	$256.34
66*	30	200	~~$170.88~~ $180.43	~~$216.00~~ $300.64

*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	~~$474.70~~ $540.45
52	25	100	H.P. Sodium	$370.88	~~$425.02~~ $448.78
53	30	400	H.P. Sodium	~~$483.20~~ $510.21	~~$743.05~~ $784.59
57	30	400	Metal Halide	$513.83	N/A
58	40	400	H.P. Sodium	~~$498.58~~ $526.45	~~$827.14~~ $873.38
59	40	400	Metal Halide	~~$529.23~~ $558.81	~~$621.92~~ $725.47

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	~~$232.57~~ $253.58	~~$282.66~~ $298.46	~~$313.43~~ $506.53
15	25	175	Mercury Vapor	~~$156.59~~ $165.34	~~$190.95~~ $201.62	N/A
16	25	100	Mercury Vapor	~~$129.97~~ $137.24	~~$164.33~~ $173.52	N/A
17	25	250	Mercury Vapor	~~$180.33~~ $190.41	~~$214.69~~ $226.69	N/A
44	40	400	Mercury Vapor	~~$262.39~~ $277.06	~~$324.17~~ $342.29	N/A
48	40	700	Mercury Vapor	~~$362.68~~ $382.95	N/A	N/A
49	40	1,000	Mercury Vapor	~~$460.39~~ $486.13	~~$522.17~~ $551.36	N/A
63	30	250	H.P. Sodium	~~$195.43~~ $206.35	~~$266.11~~ $280.99	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	~~$254.17~~ $268.38	~~$295.46~~ $311.98	~~$326.24~~ $519.27
15	25	175	Mercury Vapor	~~$175.14~~ $184.93	~~$200.70~~ $211.92	~~$234.70~~ $312.19
16	25	100	Mercury Vapor	N/A	~~$174.08~~ $183.81	N/A
17	25	250	Mercury Vapor	~~$198.88~~ $210.00	~~$224.43~~ $236.98	~~$259.70~~ $380.88
44	40	400	Mercury Vapor	N/A	~~$340.77~~ $359.82	N/A
49	40	1,000	Mercury Vapor	N/A	~~$495.69~~ $531.26	N/A
62	30	400	H.P. Sodium	N/A	N/A	~~$562.22~~ $593.65
63	30	250	H.P. Sodium	~~$217.02~~ $229.15	~~$278.91~~ $294.50	N/A
64	40	250	H.P. Sodium	N/A	~~$303.63~~ $320.60	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	~~$195.28~~ $253.65	N/A
15	25	175	Mercury Vapor	~~$122.94~~ $150.76	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	~~$234.47~~ $284.55
90	E	12	39	LED	Acorn	$348.64
90	H	16	39	LED	Acorn	$346.62
91*	A	16	70	H.P. Sodium	Globe	~~$237.91~~ $444.15
91*	E	16	39	LED	Globe	$513.53
93*	A	20	100	H.P. Sodium	Lantern	~~$233.80~~ $246.87
93*	E	20	51	LED	Lantern	$266.08

*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	~~$270.34~~ $303.63
90	F	12	39	LED	Acorn	$379.31
90	I	16	39	LED	Acorn	$377.29
91*	C	16	70	H.P. Sodium	Globe	~~$273.79~~ $463.22
91*	F	16	39	LED	Globe	$544.20
92*	C	20	100	H.P. Sodium	Top Hat	~~$213.53~~ $258.69

*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
90	J	16	39	LED	Acorn	$458.69

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
08L	12 or 16	39	LED	Acorn or Globe	$206.20
09	14	66	LED	Bounce	~~$200.49~~ $211.70
12*	12	70	H.P. Sodium	Acorn	~~$195.63~~ $206.57
13*	16	70	H.P. Sodium	Twin Acorn	$292.29
13L*	16	39	LED	Twin LED Acorn	$256.07
94*	16	70	H.P. Sodium	Acorn	~~$195.63~~ $206.57
95*	16	70	H.P. Sodium	Globe	~~$204.92~~ $216.38
96*	20	100	H.P. Sodium	Top Hat	~~$212.59~~ $224.47
97*	20	100	H.P. Sodium	Lantern	~~$212.59~~ $224.47
98*	14	150	Metal Halide	Bounce	~~$202.69~~ $214.02

*Restricted

Category No. 5: LED Lighting Methods Annual Rate

Overhead Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	*Wood Pole* Single Lamp	*Wood Pole* Twin Lamps	*Metal Pole* Single Lamp	*Metal Pole* Twin Lamps
61L	25	54	~~$102.10~~ $107.81	~~$129.56~~ $165.48	~~$139.71~~ $150.28	~~$167.17~~ $208.13
65L	40	207	~~$222.30~~ $234.73	N/A	~~$265.17~~ $279.99	N/A
66L	30	108	~~$124.37~~ $135.10	~~$156.47~~ $222.59	~~$185.10~~ $195.45	~~$217.21~~ $249.48
67L	40	108	~~$132.81~~ $153.06	N/A	~~$188.43~~ $198.96	N/A
68L	30	207	~~218.60~~ $230.86	N/A	275.52	N/A

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	*Wood Pole* Single Lamp	*Wood Pole* Twin Lamps	*Metal Pole* Single Lamp	*Metal Pole* Twin Lamps
51L	30	89	N/A	N/A	~~302.46~~ $324.50	~~424.72~~ $448.46
52L	25	46	N/A	N/A	~~282.63~~ $298.40	~~385.77~~ $407.33
53L	30	89	N/A	N/A	~~363.34~~ $383.65	~~$603.08~~ $636.79
58L	40	232	N/A	N/A	~~359.65~~ $390.70	$687.18
61L	25	54	~~$102.10~~ $127.54	~~$129.56~~ $185.39	~~$164.70~~ $173.91	~~$193.15~~ $222.71
65L	40	207	~~$252.15~~ $266.25	N/A	~~$295.01~~ $311.50	~~$445.83~~ $470.75
66L	30	108	~~$153.01~~ $161.56	~~$185.10~~ $236.62	~~$213.72~~ $225.67	~~$245.85~~ $263.51
67L	40	108	~~$158.60~~ $196.16	~~$190.69~~ $292.74	~~$214.21~~ $236.94	~~$246.31~~ $333.52
68L	30	207	N/A	N/A	$305.37	$456.18

Underground Wiring: Customer-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Single Lamp	Twin Lamps
51L	30	89	~~$184.99~~ $206.87	N/A
53L	30	89	~~$245.75~~ $259.49	N/A
58L	40	232	~~$246.86~~ $260.66	N/A
61L	25	54	~~$101.32~~ $106.98	N/A
65L	40	207	~~$214.96~~ $226.98	~~$365.77~~ $386.22
66L	30	108	~~$122.40~~ $132.47	~~$154.49~~ $219.96
67L	40	108	~~$123.48~~ $160.73	~~$155.57~~ $257.30
68L	30	207	~~$215.27~~ $227.30	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	~~$87.9~~ $92.81	N/A
30	30	200	~~$101.93~~ $107.63	N/A
31	40	200	~~$124.92~~ $131.90	N/A

Underground Wiring: OPPD-Owned Pole

Method	Approx. Mounting Height (feet)	Lamp Size (watts)	Wood Pole	Metal Pole
28	25	100	~~$88.3~~ $93.24	~~$135.82~~ $143.41
30	30	200	N/A	$192.86
31	40	200	N/A	~~$206.95~~ $218.52

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

Method	Lamp Size (watts)	Light Source	Dusk to Dawn

20	100	Mercury Vapor	~~$60.34~~ $68.87
22	250	Mercury Vapor	~~$107.29~~ $113.29
23	400	Mercury Vapor	~~$156.25~~ $164.98
23L	207	LED	~~$81.65~~ $88.85
24	700	Mercury Vapor	~~$249.98~~ $263.95
25	1,000	Mercury Vapor	~~$341.05~~ $360.11
25L	529	LED	~~$149.82~~ $177.76
27	150	Incandescent	~~$65.93~~ $73.86
40	54	LED	~~$39.30~~ $48.64
41	86	LED	$69.25
42	48	LED	~~$36.16~~ $44.82
43	168	LED	~~$58.43~~ $81.15
71	100	H.P. Sodium	~~$65.28~~ $73.46
71L	58	LED	~~$50.10~~ $52.90
72	150	H.P. Sodium	~~$82.55~~ $89.66
73	250	H.P. Sodium	~~$112.23~~ $118.50
74	400	H.P. Sodium	~~$162.41~~ $171.49
74L	207	LED	~~$81.65~~ $88.85
76	200	H.P. Sodium	~~$96.90~~ $102.32
76T	200	Twin H.P. Sodium	$176.38
76L	10~~1~~8	LED	~~$53.01~~ $63.09
76LT	108	Twin LED	$91.34
77	50	H.P. Sodium	~~$42.29~~ $51.55
77L	25	LED	~~$43.11~~ $45.52
78	70	H.P. Sodium	~~$48.46~~ $57.63

79	1,000	H.P. Sodium	~~$349.02~~ $368.53
80	100	Metal Halide	~~$58.65~~ $66.72
80L	65	LED	~~$51.58~~ $54.46
81	175	Metal Halide	~~$82.87~~ $89.56
81L	48	LED	~~$47.98~~ $50.66
81LT	48	Twin LED	$61.40
82	250	Metal Halide	~~$107.75~~ $113.77
82L	100	LED	~~$58.99~~ $62.29
83	400	Metal Halide	~~$150.98~~ $159.42
87	50	Metal Halide	~~$39.36~~ $50.55

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	~~$63.86~~ $67.43
75L	54	LED	~~$36.49~~ $49.22
75LT	108	Twin LED	~~$51.19~~ $63.46

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 fixture, lamp, photocell, and pole, that 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	~~8.53~~8.88 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 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 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) 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	~~9.78~~9.81 ¢/kWh	7.89 ¢/kWh
1,001-3,000 kWh	~~8.40~~9.81 ¢/kWh	7.89 ¢/kWh
3,001+ kWh	~~8.40~~9.81 ¢/kWh	5.24 ¢/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) 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 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 month plus,

Demand Charge:

Billing Demand	Per kW Month
Per kW	$~~5.38~~7.08

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	~~5.93~~5.92 cents/kWh
All additional kWh	5.81 cents/kWh	~~4.50~~4.56 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. 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: $ ~~116.70~~147.30

The minimum monthly bill is calculated as the 18-kilowatt minimum Demand requirements of $~~96.84~~127.44, 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

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~~, 261~~, 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 ~~1.606~~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- 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~~, 261~~, and 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-owned 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-owned 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 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 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

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. 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

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. 467 OPTIONS E & V

General Service – Emergency/Volunteer Curtailable

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. 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

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.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
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, 250~~, 261~~.

This Rider Schedule cannot be combined with Rider Schedule Nos. 464, 467, 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	$ ~~24.50~~22.50
Landlords	$ ~~17.00~~15.00

(470B): Reconnect Service after delinquent bill disconnect $ 75.00

(470C): Disconnect following unauthorized reconnect - each occurrence $115.00

(470D): Field collection call - no disconnect $ 30.00

(470E): Returned payment fee $ 30.00

(470F): Line Extension (Residential) charges

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 transfer switch charges to be actual cost plus overhead (ACPO)

200 amp transfer switch	-	ACPO
400 amp transfer switch	-	ACPO

(470H): Line extensions and temporary service disconnects (General Service) charges

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

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

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

All 3-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 for the joint use of OPPD's poles is $~~11.55~~13.70 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-owned 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 Due to an Inaccessible Meter / Non-Automated Meter Read (AMR) Meters

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

ADMINISTRATIVE

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.

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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 ~~or 261~~, 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.

Return to Rates and Riders List

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~~, or 261~~ 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~~, 261~~ 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.

Omaha Public Power District

Board Action

BOARD OF DIRECTORS

December 19, 2023

ITEM

2024 Corporate Operating Plan and Rate Action

PURPOSE

Submittal of the 2024 Corporate Operating Plan and rate action for approval by the Board of Directors.

FACTS

a. The Corporate Operating Plan includes an average general rate increase across all customer classes of 3.1%. The Fuel and Purchased Power Adjustment (FPPA) base rate was reset to account for long-term price increases in the supply of power. This result has a decrease in the FPPA factor with an average rate impact across all customer classes of -0.6%. Total rate impact across all customer classes is 2.5%.
   - The current FPPA factor is 0.480 cents per kWh. The FPPA base rate is 1.606 cents per kWh.
   - Management will propose to change the FPPA base rate to 1.951 cents per kWh. This will result in a reduction of the FPPA factor to 0.413 cents per kWh.
   - The net results of the resetting of the FPPA base and impact on FPPA factor is a -0.6% rate impact.
   - The 2024 Corporate Operating Plan includes a one-time 100% exclusion of under-collected FPPA revenue. FPPA under collected revenues are currently projected to be $6.8 million and will be updated with actual results through December 2023. This exclusion is a result of favorable financial results that does not require recovery of under-collected revenues.

b. A Cost-of-Service Study was performed to determine the cost of providing electric service to each rate class. The study was used to determine the appropriate rate increase for each class.

Customer Class	FPPA Rate	General Rate	Total
Residential	-0.6%	2.2%	1.6%
Commercial	-0.8%	5.8%	5.0%
Industrial	-0.6%	2.4%	1.8%
Lighting	-0.2%	6.1%	5.9%
Wholesale Towns	-0.9%	0.0%	-0.9%
Total	-0.6%	3.1%	2.5%

The proposed increased 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 17,399 GWh which represents a 10.9% increase from the projected 2023 sales amount.
   - Retail sales are budgeted to be 13,648 GWh which represents a 9.5% increase from the projected 2023 amount.
   - Wholesale revenues, excluding Nebraska City Station Unit 2 (NC2) participation sales, are budgeted to be 1,653 GWh which represents an 12.0% increase from the projected 2023 amount.
     - NC2 participation sales for 2023 are budgeted to be 2,097 GWh, a 20.5% increase from the projected 2023 amount.

e. Total operating revenues are budgeted to be $1,432.4 million. Total budgeted operating revenues are 1.6% higher than 2023 projection.
   - Retail revenues are budgeted to be $1,225.6 million, which is an increase of $67.5 million or 5.8% above the 2023 projection.
   - Wholesale revenues, excluding NC2 participation revenues, are budgeted to be $100.9 million, which is 27.1% lower than 2023 projected revenues.
     - NC2 participation revenues for 2024 are budgeted to be $63.6 million, a 7.5% decrease from the projected 2023 amount.

f. Total operations and maintenance expenditures are budgeted to be $1,021.0 million. Total operations and maintenance expenditures are $0.6 million or 0.1% lower than the 2023 projected amount.
   - Operations and maintenance expenditures (excluding fuel and purchased power) are budgeted to be $528.3 million, which is $12.6 million or 2.3% lower than the amount projected for 2023.
   - Fuel expenses are budgeted to be $180.2 million which is $18.5 million or 11.5% higher than the amount projected for 2023.
   - Purchased power expenses are budgeted to be $312.5 million which is $6.5 million or 2.0% lower than the amount projected for 2023. The purchased power expenses include 972 megawatts of wind capability and 86 megawatts of solar capability, to support the District's renewable energy goal.

g. Capital expenditures are budgeted at $727.0 million for 2024 compared to $651.4 million projected for 2023.

   The 2024 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	$ 261.3 million
Transmission and Distribution	356.2 million
General	109.5 million
TOTAL	$727.0 million

h. In 2024, funding for Nuclear Decommissioning is budgeted at $15.3 million, consisting of investment earnings on trust balances.

i. Net income for 2024 is budgeted to be $161.4 million compared to $145.5 million projected for 2023.

j. The 2024 Corporate Operating Plan total expenditure amount equals $2,107.7 million.

k. Total debt service coverage is anticipated to be 2.0 times for 2024.

ACTION
Approval of the 2024 Corporate Operating Plan and rate changes.

RECOMMENDED:
DocuSigned by:
Jeff Bishop
65F902772CFE45A...
Jeffrey M. Bishop
Vice President and Chief Financial Officer

APPROVED FOR REPORTING TO THE BOARD:
DocuSigned by:
L. Javier Fernandez
AC399FDCE56247E...
L. Javier Fernandez
President and Chief Executive Officer

JMB:bjs

Attachments: 2024 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