MEAN
Municipal Energy Agency of Nebraska

Budget, Rates, and Charges
Fiscal Year 2026-2027

Projections based on Actual Results through September 2025

Board of Directors Meeting
January 22, 2026

Finance Committee Meeting
January 21, 2026

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For ease of review, Staff highlighted changes to the cost components of the revenue requirement between the original Proposed Budget information provided to MEAN Committees in December 2025 and this current information if the change exceeded $50,000. Rates and charges and the related budgeted amounts for electric energy sales were also updated in the Proposed Budget to reflect the rates and charges proposed to be effective April 1, 2026. As these changes were expected, these items are not highlighted.

MEAN's Fiscal Year is April 1 to March 31. Throughout this packet, Proposed Budget refers to Fiscal Year 2026-2027 and Current Budget and Projected both refer to Fiscal Year 2025-2026. When needed, reclasses have been made to the Current Budget to reflect the current accounting treatment. These items reclass dollars from one line item to another with no impact on budgeted net revenue, budgeted debt service coverage, or change in operating fund.

Information and explanations of Projected were provided to the MEAN Committees in December 2025 in a separate Year-End Projections packet. Information in this current packet has not been updated for actual results through November 2025. More information regarding Year-End Projections will be presented at the January 2026 meetings.

More information will be provided throughout the materials; however, the following are key items to note related to the Proposed Budget, Rates, and Charges:

- Rates and charges reflect the impact of a Service Schedule M Participant's transition from Requirements Purchaser (M-RP) to Contract Purchaser (M-CP) effective April 1, 2026.
- The budget includes estimates for transactions beginning April 1, 2026, that will occur because of expanded market activities in MEAN's operating footprint.

Rates and Charges Summary

The proposed increase in rates and charges as shown in the following table results in an overall increase in MEAN's rates and charges of 3%. The change shown in the *Rates and Charges Summary* for the Fixed Cost Recovery Charge (FCRC) is due to a portion of these costs now being recovered through rates and charges for Contract Purchasers. See the Schedules of Rates and Charges for Service Schedules M, K, and K-1 included with the meeting materials for individual FCRC and Administrative Charge allocations. Please contact MEAN staff if you'd like additional information regarding impacts to your community's power costs including costs for transmission and power and energy from Western Area Power Administration (WAPA).

Rate/Charge	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Fixed Cost Recovery Charge - Schedules M-RP, K and K-1	$ 45,700,000	$ 47,500,000	$ (1,800,000)	-4%
Energy Charge Rate ($/MWh) - Schedule M-RP	$ 51.00	$ 47.66	$ 3.34	7%
Energy Charge Rate ($/MWh) - Schedules K and K-1	$ 53.55	$ 50.05	$ 3.50	7%
Green Energy Charge Rate ($/MWh) - Schedule M-RP	$ 53.55	$ 50.05	$ 3.50	7%
Green Energy Charge Rate ($/MWh) - Schedules K and K-1	$ 56.23	$ 52.56	$ 3.67	7%
Related Projects Charge ($/MWH) - Schedule M-CP	$ 60.68		N/A	N/A
Administrative Charge - Schedule M-CP	$ 640,872		N/A	N/A
Transmission (Pass Through)	Billed at Transmission Provider's Rates			
Western Area Power Administration (WAPA) (Pass Through)	Billed at WAPA's Rates			

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Revenue Requirement

The cash costs and rate offsets that comprise the cost components of the revenue requirement are summarized below.

Revenue Requirement - Cost Components	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Cash Costs				
Purchased Power	$ 86,663,936	$ 81,833,339	$ 4,830,597	6%
Production	18,164,984	19,221,358	(1,056,374)	-5%
Transmission	8,379,707	7,669,788	709,919	9%
A&G	16,785,885	16,687,995	97,890	1%
MEAN and Owned Generation Capital	3,245,527	6,177,967	(2,932,440)	-47%
MEAN Debt Service	9,433,338	9,426,588	6,750	0%
MEAN Subscription Liability Payment	503,728	429,891	73,837	17%
MEAN Lease Liability Payment	999,153	970,053	29,100	3%
Total Cash Costs	**144,176,258**	**142,416,979**	**1,759,279**	**1%**
Rate Offsets				
Electric Energy Sales - Schedule M-CP	(7,936,175)	-	(7,936,175)	0%
Electric Energy Sales - Schedule J	(689,606)	(1,054,658)	365,052	-35%
Electric Energy Sales - Non-Participants	(360,000)	(360,000)	-	0%
Other Operating Revenues	(2,477,414)	(2,344,208)	(133,206)	6%
Investment Return	(2,114,375)	(1,949,750)	(164,625)	8%
Total Rate Offsets	**(13,577,570)**	**(5,708,616)**	**(7,868,954)**	**138%**
Total Revenue Requirement - Cost Components	**$ 130,598,688**	**$ 136,708,363**	**$ (6,109,675)**	**-4%**

The revenue requirement is met through operating revenues from electric energy sales to Service Schedule M Requirements Purchasers (M-RP) and Schedule K and K-1 Participants. As shown below, cash on hand may also be used to meet the revenue requirement.

Revenue Requirement - Revenues and Cash	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Electric Energy Sales - Schedules M-RP, K, and K-1				
Fixed Cost Recovery Charge	$ 45,700,000	$ 47,500,000	$ (1,800,000)	-4%
Energy Charge	75,114,877	73,287,618	1,827,259	2%
Green Energy Charge	16,739,158	15,418,614	1,320,544	9%
Total Electric Energy Sales - M-RP, K, and K-1	**137,554,035**	**136,206,232**	**1,347,803**	**1%**
Use of/(Addition to) Cash on Hand				
Use of/(Addition to) Cash on Hand - FCRC*	(2,329,400)	213,219	(2,542,619)	-1,192%
Use of/(Addition to) Cash on Hand - Energy*	(4,625,947)	288,912	(4,914,859)	-1,701%
Total Use of/(Addition to) Cash on Hand	**(6,955,347)**	**502,131**	**(7,457,478)**	**-1,485%**
Total Revenue Requirement - Revenues and Cash	**$ 130,598,688**	**$ 136,708,363**	**$ (6,109,675)**	**-4%**

*May consist of operating and/or rate stabilization funds.

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Service Schedule M Requirements Purchasers Energy Charge Components

The M-RP Energy Charge is calculated as summarized below.

Service Schedule M-RP Energy Charge	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Cash Costs				
Purchased Power, net of Debt and Capital in FCRC	$ 70,264,445	$ 65,735,951	$ 4,528,494	7%
Production	18,164,984	19,221,358	(1,056,374)	-5%
Transmission	8,379,707	7,669,788	709,919	9%
MEAN Lease Liability Payment	999,153	970,053	29,100	3%
Total Cash Costs	**97,808,289**	**93,597,150**	**4,211,139**	**4%**
Rate Offsets				
Electric Energy Sales to Participants - Energy Charge Cost Offsets	(24,333,871)	(17,204,388)	(7,129,483)	41%
Electric Energy Sales to Non-Participants	(360,000)	(360,000)	-	0%
Other Operating Revenues - Energy Charge Cost Offsets	(1,665,420)	(1,602,348)	(63,072)	4%
Investment Return - Operating and Rate Stabilization	(1,729,000)	(1,585,000)	(144,000)	9%
Total Rate Offsets	**(28,088,291)**	**(20,751,736)**	**(7,336,555)**	**35%**
Net SSM-RP Energy Charge Costs	**69,719,998**	**72,845,414**	**(3,125,416)**	**-4%**
Addition to/(Use of) Cash on Hand				
Addition to/(Use of) Operating Fund	4,625,947	(288,912)	4,914,859	-1,701%
Total Addition to/(Use of) Cash on Hand	**4,625,947**	**(288,912)**	**4,914,859**	**-1,701%**
Total SSM-RP Energy Charge	**$ 74,345,945**	**$ 72,556,502**	**$ 1,789,443**	**2%**
Energy Charge Units - SSM-RP (MWh)	1,457,764	1,522,377	(64,614)	-4%
SSM-RP Energy Charge $/MWh	**$ 51.00**	**$ 47.66**	**$ 3.34**	**7%**

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Fixed Cost Recovery Charge Components

The Fixed Cost Recovery Charge section of the *Electric Energy Sales Narrative* provides a detailed description of the components and the method of allocation by Participant. The Fixed Cost Recovery Charge components are summarized below.

Fixed Cost Recovery Charge	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-
Cash Costs				
A&G	$ 16,785,885	$ 16,687,995	$ 97,890	1%
MEAN Subscription Liability Payment	503,728	429,891	73,837	17%
MEAN and Owned Generation Capital	3,245,527	6,177,967	(2,932,440)	-47%
Contracted Generation Capital	1,247,037	1,235,916	11,121	1%
MEAN Debt Service	9,433,338	9,426,588	6,750	0%
Contracted Generation Debt Service, net	15,152,454	14,861,472	290,982	2%
Total Cash Costs	**46,367,969**	**48,819,829**	**(2,451,860)**	**-5%**
Rate Offsets				
Electric Energy Sales to Participants - FCRC Cost Offsets	(1,800,000)	-	(1,800,000)	100%
Other Operating Revenues - FCRC Cost Offsets	(811,994)	(741,860)	(70,134)	9%
Investment Return - Debt Service	(385,375)	(364,750)	(20,625)	6%
Total Rate Offsets	**(2,997,369)**	**(1,106,610)**	**(1,890,759)**	**171%**
Net FCRC Costs	**43,370,600**	**47,713,219**	**(4,342,619)**	**-9%**
Use of Cash on Hand				
Addition to/(Use of) Operating Fund	2,329,400	(213,219)	2,542,619	-1,192%
Total Addition to/(Use of) Cash on Hand	**2,329,400**	**(213,219)**	**2,542,619**	**-1,192%**
Total Fixed Cost Recovery Charge	**$ 45,700,000**	**$ 47,500,000**	**$ (1,800,000)**	**-4%**

Rate Setting Philosophy

The budget for Municipal Energy Agency of Nebraska (MEAN) consists of a number of underlying assumptions, many of which have the potential to be impacted by regional, regulatory and weather events that are outside the control of MEAN staff or Participants. Information included provides for further discussion and understanding of the potential for variances between actual and budgeted results.

Utility basis budgeting considers the future replacement of assets and power supply contracts. Under utility basis budgeting, the revenue requirement includes annual operating expenses, depreciation expense and a return on system equity. The rate of return on system equity is determined by including an inflationary increase in asset replacement costs plus interest expense. The advantage of utility basis budgeting is that it leads to more stable and consistent rate adjustments and typically leads to a more financially stable and healthy organization. During the budget process staff reviews the cash basis and utility basis revenue requirements and selects a targeted revenue requirement based on analysis of all of MEAN's various financial targets and guidelines.

In proposing the annual rates, staff also considers the following priorities discussed with the MEAN Finance Committee:

- Smaller incremental changes to overall rates and charges
- No large (>10%) swings year to year
- No mid-year rate changes
- Maintain levels of operating and rate stabilization funds in accordance with established targets
- Fund and utilize additional rate stabilization funds for large cyclical costs, not for general cost increases
- Balance financial targets and ratio coverage to achieve the priorities noted

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In accordance with the Annual Budget and Financial Forecasts section of MEAN's Financial and Administrative Policies and Guidelines, MEAN prepares at least a five-year financial forecast based on projected costs and load requirements. This forecast is used to develop a preliminary targeted revenue requirement for future years.

Historical Rates and Charges

The following table includes a five-year history of MEAN's M-RP, K, and K-1 rates and charges.

	Board Approved Rates & Charges					Proposed
	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027
Fixed Cost Recovery Charge (FCRC) - Schedules M-RP, K, and K-1						
FCRC	$ 43,900,000	$ 42,900,000	$ 42,900,000	$ 42,900,000	$ 47,500,000	$ 45,700,000
$ Change	$ -	$ (1,000,000)	$ -	$ -	$ 4,600,000	$ (1,800,000)
% Change	0%	-2%	0%	0%	11%	-4%
Energy Charge Rate ($/MWh)						
Schedule M-RP	$ 38.25	$ 40.70	$ 40.70	$ 43.60	$ 47.66	$ 51.00
$ Change	$ -	$ 2.45	$ -	$ 2.90	$ 4.06	$ 3.34
% Change	0%	6%	0%	7%	9%	7%
Schedules K and K-1	$ 40.17	$ 42.74	$ 42.74	$ 45.78	$ 50.05	$ 53.55
$ Change	$ -	$ 2.57	$ -	$ 3.04	$ 4.27	$ 3.50
% Change	0%	6%	0%	7%	9%	7%
Green Energy Charge Rate ($/MWh)						
Schedule M-RP			$ 42.74	$ 45.78	$ 50.05	$ 53.55
$ Change				$ 3.04	$ 4.27	$ 3.50
% Change				7%	9%	7%
Schedules K and K-1			$ 44.88	$ 48.07	$ 52.56	$ 56.23
$ Change				$ 3.19	$ 4.49	$ 3.67
% Change				7%	9%	7%

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Other Rates and Charges Narrative
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Avoided Cost and Standard Rate

MEAN has established a methodology to develop the standard Avoided Cost rate for purchases from Qualifying Facilities with a design capacity of 100 kW or less under the Public Utility Regulatory Policies Act. Qualifying Facilities greater than 100 kW will be treated on a case-by-case basis as allowed by federal regulations.

The standard Avoided Cost rate is calculated in accordance with the Avoided Cost and Standard Rate section of MEAN's Financial and Administrative Policies and Guidelines. This is the rate at which MEAN will compensate total requirements participants for net excess energy produced by end-use customer owned Qualifying Facilities with a design capacity of 100 kW or less interconnected to the Participant's distribution system. Qualifying Facilities are defined by federal law to include renewable generation such as solar, wind, and hydro.

The rate changes each calendar year because of fluctuations in electric energy market prices. See the following table for a five-year summary. The calendar year rate is derived from the previous completed fiscal year. For example, calendar year 2026 is derived from Fiscal Year 2024-2025.

	Calendar Year				
	2022	2023	2024	2025	2026
Standard Avoided Cost Rate ($/MWh)	$ 42.09	$ 34.52	$ 55.54	$ 46.60	$ 55.06
$ Change	$ 17.05	$ (7.57)	$ 21.02	$ (8.94)	$ 8.46
% Change	68%	-18%	61%	-16%	18%

Capacity Commitment Compensation

The various capacity commitment compensation rates and payments are in accordance with the Capacity Commitment Compensation section of MEAN's Financial and Administrative Policies and Guidelines. Eligibility for payment for Contract Capacity and compensation for energy production will be in accordance with the Asset Management Policies and Procedures (AMPP). A summary of the various rates to be reviewed and approved by the Board of Directors follows:

Rate	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Demand Rate ($/kW per Month)	$ 3.00	$ 2.50	$ 0.50	20%
Variable O&M Rate ($/MWh)	$ 5.00	$ 5.00	$ -	0%
Labor Rate ($ per unit Operating Hour)	$ 44.00	$ 44.00	$ -	0%

Hourly Rate

Certain MEAN services include an administrative fee which is billed at the then current hourly rate. The administrative fee is further explained in the Financial and Administrative Policies and Guidelines. The rate per hour is included in the Schedules of Rates and Charges for Service Schedule M, K, and K-1 and is subject to approval by the Board of Directors.

Rate	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-
Hourly Rate	$ 185.00	$ 180.00	$ 5.00	3%

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January 2026 Meetings

	Projected 2025-2026	Proposed Budget 2026-2027
Revenue Requirement	$ 136,708,363	$ 130,598,688
% increase / (decrease)		-4%
Net Revenue / (Loss)	$ 5,367,252	$ 6,940,061
Change in Unrestricted Funds		
Operating Fund	$ 2,150,140	$ 6,955,347
Debt Service Coverage	1.77	1.93
Policy target of 1.20X; requirement of 1.00X		
Cash Reserve (Rate Stabilization Fund - Reserve + Operating Fund)		
Minimum, Per Policy	$ 48,688,505	$ 50,235,047
Cash Reserve - Estimated End of Fiscal Year^	$ 51,571,712	$ 58,527,059
Amount Over/(Under) Minimum	$ 2,883,207	$ 8,292,012

See the *Budget Summary Narrative – Rate Setting Philosophy* and the *Unrestricted Funds* sections for more information.

^The Operating Fund balance is impacted by the timing of collection of revenues and payment of costs. An estimate of the expected impact of timing variances at September 2025 is included in the estimated 2025-2026 balance shown; actual results could vary significantly. The Projected balance includes the calculated change of approximately $2.7 million plus $3.3 million related to timing variances.

Final year-end results could differ substantially from Projected. Final analysis related to suggested year-end activity including rate stabilization transactions will be completed once Fiscal Year 2025-2026 preliminary results are available in May 2026.

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Unrestricted Funds Narrative
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Unrestricted Funds

Unrestricted funds include MEAN's rate stabilization fund and operating fund. Projecting the operating fund balance is challenging due to the inherent timing variances that exist at any point in time. In projecting the year-end balance, staff attempts to account for known timing variances. The balance shown for the Proposed Budget ignores timing variances and assumes the revenues and costs related to each fiscal year are cash settled within that year.

Fund Targets and Goals

The MEAN Board of Directors has established various targets and goals for MEAN's funds. MEAN's Financial and Administrative Policies and Guidelines along with resolutions made by the Board of Directors serve as documentation. MEAN's Cash Reserve Policy states, "MEAN recognizes that financially healthy agencies have fund balances that range from the minimum, established by the cash reserve guidelines, up to 2.5 times the minimum."

Operating

As part of MEAN's Cash Reserve, MEAN's goal (see the Liquidity Policy) is to maintain the balance in the operating fund at least equal to the sum of the following:

- at least 60 days of budgeted cash operating expenses
- at least 45 days of budgeted pass through expenses

Rate Stabilization

To facilitate tracking of the accumulation of and intended use of funds, MEAN has various components within the Rate Stabilization Account. When evaluating the Rate Stabilization Account, MEAN will consider the total of all funds held. Funds may be moved between the various components and all amounts on deposit may be used at the discretion of the Board.

The Rate Stabilization Account Policy states, "It is not the intent of MEAN to fund routine rate adjustments with funds from the Reserve component of the rate stabilization fund. The Reserve component is intended to be used only to handle the impact of unforeseen or one-time events that have a significant financial impact. MEAN may utilize funds within the rate stabilization account, that are in excess of MEAN's goal for the Reserve component, to minimize annual rates and charges fluctuations up or down."

Reserve – as part of MEAN's Cash Reserve, MEAN's goal is to maintain funds in the rate stabilization account at least equal to the following:

- 15% of budgeted cash operating expenses, excluding purchased power capital; plus, annual average of preliminary 5-year capital budget, including purchased power capital.

The Board has funded the reserve component at $24.6 million ($20.1 million at the May 2022 meeting, plus $2.0 million at the May 2024 meeting, plus $2.5 million at the May 2025 meeting).

Energy – as determined by the Board for managing volatility in the underlying components of the Energy Charge. There are currently no funds in the energy component nor has the Board established a goal for this component.

Fixed Costs – as determined by the Board for managing volatility in the underlying components of the Fixed Cost Recovery Charge. There are currently no funds in the fixed costs component nor has the Board established a goal for this component.

Other – as determined by the Board for items such as debt strategy, resource planning, etc. At the May 2022 meeting, the Board established a goal to accumulate funds within the rate stabilization account – other component as follows:

- $1.5 million annually for 30 years beginning with the Fiscal Year ended March 31, 2022.

The Board has funded the other component at $4.5 million (approx. $1.3 million at the May 2022 meeting plus approx. $3.2 million at the May 2023 meeting).

See the *Unrestricted Funds Analysis* report for more information.

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January 2026 Meetings	Projected 2025-2026	Proposed Budget 2026-2027
Rate Stabilization Fund		
Reserve		
Minimum Reserve, Per Policy	$ 24,552,170	$ 25,042,499
Annual Change in Balance	$ -	$ -
Balance - End of Fiscal Year	$ 24,600,000	$ 24,600,000
Amount Over/(Under) Minimum	$ 47,831	$ (442,499)
Other		
Determined Goal	$ 7,500,000	$ 9,000,000
Annual Change in Balance	$ -	$ -
Balance - End of Fiscal Year	$ 4,500,000	$ 4,500,000
Amount Over/(Under) Goal	$ (3,000,000)	$ (4,500,000)
Total Rate Stabilization Fund		
Minimum Reserve + Goals	$ 32,052,170	$ 34,042,499
Annual Change in Balance	$ -	$ -
Balance - Estimated End of Fiscal Year	$ 29,100,000	$ 29,100,000
Amount Over/(Under) Minimum + Goals	$ (2,952,170)	$ (4,942,499)
Operating Fund		
Minimum Reserve, Per Policy	$ 24,136,335	$ 25,192,548
Annual Change in Balance^	$ 6,025,806	$ 6,955,347
Balance - Estimated End of Fiscal Year^	$ 26,971,712	$ 33,927,059
Amount Over/(Under) Minimum	$ 2,835,377	$ 8,734,511
Total Unrestricted Funds		
Minimum Reserve + Goals	$ 56,188,505	$ 59,235,047
Annual Change in Balance	$ 6,025,806	$ 6,955,347
Balance - End of Fiscal Year	$ 56,071,712	$ 63,027,059
Amount Over/(Under) Minimum + Goals	$ (116,793)	$ 3,792,012

See the *Unrestricted Funds* narrative for more information.

^The Operating Fund balance is impacted by the timing of collection of revenues and payment of costs. An estimate of the expected impact of timing variances at September 2025 is included in the annual change in balance and resulting estimated 2025-2026 balance shown; actual results could vary significantly. The Projected annual change in balance includes the calculated change of approximately $2.7 million plus $3.3 million related to timing variances.

Final year-end results could differ substantially from Projected. Final analysis related to suggested year-end activity including rate stabilization transactions will be completed once Fiscal Year 2025-2026 preliminary results are available in May 2026.

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	Proposed Budget	Current Budget	Proposed vs. Current +/-	Proposed vs. Current % +/-	Projected
Electric Energy Sales - MWh's					
Schedule M	1,751,277	1,687,370	63,907	4%	1,698,036
Schedules K and K-1	147,027	150,847	(3,820)	-3%	147,598
Schedule J	11,491	18,496	(7,005)	-38%	18,885
Non-participants	-	-	-	-	151,309
Total electric energy sales - MWh's	**1,909,794**	**1,856,713**	**53,082**	**3%**	**2,015,827**
Operating Revenues					
Electric energy sales					
Schedule M	$ 133,553,177	$ 124,604,856	$ 8,948,321	7%	$ 125,123,108
Schedules K and K-1	11,937,033	11,601,376	335,657	3%	11,429,222
Schedule J	689,606	1,054,658	(365,052)	-35%	1,080,294
Non-participants	360,000	360,000	-	0%	5,482,080
Total electric energy sales	146,539,816	137,620,890	8,918,926	6%	143,114,704
Other	2,477,414	2,344,208	133,206	6%	3,327,775
Total operating revenues	149,017,230	139,965,098	9,052,132	6%	146,442,479
Operating Expenses					
Electric energy costs					
Purchased power	86,663,936	81,833,339	4,830,597	6%	91,114,437
Production	18,164,984	19,221,358	(1,056,374)	-5%	17,802,974
Transmission	8,379,707	7,669,788	709,919	9%	7,900,494
Total electric energy costs	113,208,627	108,724,485	4,484,142	4%	116,817,905
Administrative and general					
Payroll and benefits	8,858,462	8,765,196	93,266	1%	7,723,853
Internal office	1,490,934	1,498,821	(7,887)	-1%	1,433,645
Member	397,877	388,415	9,462	2%	386,217
Consultants and outside services	6,038,612	6,035,563	3,049	0%	3,549,148
Total administrative and general	16,785,885	16,687,995	97,890	1%	13,092,863
Depreciation and amortization	9,972,185	9,298,748	673,437	7%	9,624,978
Total operating expenses	139,966,697	134,711,228	5,255,469	4%	139,535,746
Operating Income/(Loss)	9,050,533	5,253,870	3,796,663	72%	6,906,733
Nonoperating Revenues/(Expenses)					
Net costs to be recovered in future periods	(342,831)	(85,961)	(256,870)	299%	(55,337)
Investment return	2,114,375	1,949,750	164,625	8%	2,654,963
Interest expense	(3,882,016)	(4,139,113)	257,097	-6%	(4,139,107)
Net nonoperating revenues/(expenses)	(2,110,472)	(2,275,324)	164,852	-7%	(1,539,480)
Net Revenue / (Loss)	**$ 6,940,061**	**$ 2,978,546**	**$ 3,961,515**	**133%**	**$ 5,367,252**
Reconciliation to Change in Unrestricted Funds					
Operating Fund:					
Net Revenue / (Loss)	$ 6,940,061	$ 2,978,546	$ 3,961,515	133%	$ 5,367,252
- MEAN debt service - principal	(5,115,000)	(4,865,000)	(250,000)	5%	(4,865,000)
- MEAN lease - principal	(333,269)	(294,800)	(38,469)	13%	(294,800)
- MEAN subscriptions	(454,363)	(376,048)	(78,315)	21%	(376,048)
- MEAN interest expense amortization	(1,151,571)	(1,151,571)	-	0%	(1,151,571)
- MEAN and owned generation capital	(3,245,527)	(6,177,967)	2,932,440	-47%	(6,210,008)
+ Depreciation and amortization	9,972,185	9,298,748	673,437	7%	9,624,978
+/- Net costs to be recovered in future periods	342,831	85,961	256,870	299%	55,337
Operating Fund	**6,955,347**	**(502,131)**	**7,457,478**	**-1,485%**	**2,150,140**
Rate Stabilization Fund	**-**	**-**	**-**	**-**	**-**
Total Change in Unrestricted Funds	**$ 6,955,347**	**$ (502,131)**	**$ 7,457,478**	**-1,485%**	**$ 2,150,140**

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Electric Energy Sales

Energy sales to Requirements Purchasers are highly variable as usage depends on consumer needs which vary with weather, time of day, conservation efforts including energy efficiency, etc. MEAN's rate structure includes a Fixed Cost Recovery Charge (FCRC) to cover certain costs related primarily to MEAN's ownership of generation, contracted purchase of generating capacity, and the operation of MEAN. These costs are fixed in that they are incurred by MEAN regardless of whether electric energy is sold by MEAN. Including the FCRC in MEAN's rate structure greatly reduces MEAN's revenue volatility. See the *Electric Energy Sales* report for detailed information.

In accordance with the Service Schedule M Total Power Requirements Power Purchase Agreement ("Legacy SSM Agreement") between MEAN and the Participant that has elected to be a Contract Purchaser, beginning April 1, 2026, MEAN provides, and the Participant purchases the Contract Demand established as defined in the Legacy SSM Agreement. The budgeted MWh for Sales to the Contract Purchaser is equal to the fixed amount determined by the Legacy SSM Agreement.

The following table summarizes the budgeted MWh for Sales to Participants. Fluctuations between years are impacted by the various factors noted above, Participant contract changes, and impacts on volumes due to changes in Western Area Power Administration (WAPA) allocations and renewable distributed generation.

	Proposed	Current	Proposed vs. Current	
Sales (MWh)	Budget	Budget	+/-	% +/-
Schedule M	1,751,277	1,687,370	63,907	4%
Schedules K and K-1	147,027	150,847	(3,820)	-3%
Schedule J	11,491	18,496	(7,005)	-38%

Participant Contract Terms

Sales volumes year to year are impacted by contract terms for Participants. Although staff actively works with Participants to continue a relationship with MEAN, for purposes of the budget and five-year financial forecast, staff makes assumptions related to potential changes at the end of each contract term. The following summarizes Schedules K, K-1, and J Participants and related contract terms:

Schedules K and K-1	Term (Years)	Contract End Date
Glenwood Springs, CO	10	5/31/2029
Wray, CO	10	6/30/2033

Schedule J	Term (Years)	Contract End Date
Lake View, IA	5	5/31/2029
Snyder, NE*	5	5/31/2026
Trenton, NE	10	12/31/2031

*Transitioning to Schedule M during the Proposed Budget effective June 1, 2026

Load Forecasting

MEAN continues to forecast loads (energy usage) for Participants based on historical results, model-based growth, and load forecast survey results. In the proposed budget, MEAN utilized a forecasting methodology that employs an industry-standard multi-variable regression analysis that includes up to 17 years of historical weather variables (includes average temperature, Cooling Degree Days (CDD), Heating Degree Days (HDD), Maximum Temperature, Minimum Temperature, One and Two-Day Delaying Temperature), calendar variables (includes months and weekdays), and economic variables (includes population and income unique to each Participant). This forecasting methodology attempts to budget a weather normalized load. For the energy forecast, staff utilized the monthly load forecast results along with each Participant's historical average monthly load factor to calculate budgeted monthly energy.

Budgeted monthly energy for Participants includes the estimated impact of the installation of solar facilities by Participants under MEAN's Renewable Distributed Generation Policy. The Current Budget did not anticipate a full fiscal year of generation from these facilities. In the Proposed Budget, an entire fiscal year of generation is budgeted. Generation from the solar facilities reduces the amount of energy purchased from MEAN by the applicable Participants. The reduction in

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revenues to MEAN is partly offset by reduced purchases for load in the respective energy markets. See the Participant Resources table in the *Purchased Power Expenses Narrative.*

Operating revenues from sales of energy to Schedules M-RP, K, and K-1 Participants are variable based on actual usage, while many of the related contracted quantities and costs to purchase energy are fixed. Through generation ownership, assignment agreements, participation agreements, and purchase power contracts, MEAN often must "take or pay" a certain level of energy regardless of MEAN Participant required loads.

Fixed Cost Recovery Charge – Requirements Purchasers
The FCRC consists of certain costs related primarily to MEAN's ownership of generation, contracted purchases of generating capacity, and the operation of MEAN and include the following:

- Costs
    - administrative and general expenses (see the *Administrative and General Expenses* report for detailed amounts)
    - subscription liability payments for subscription-based information technology agreements (SBITA) that qualify for SBITA reporting under accounting standards as these payments are effectively administrative and general costs related to the operation of MEAN (see the *Administrative and General Expenses* report for detailed amounts)
    - MEAN annual capital budget including MEAN capital assets (see the *NMPP Energy Capital Plan* report for detailed amounts) and productive capacity assets for MEAN's share of owned generation (see the *Capital Plan* report for detailed amounts) which includes Laramie River Station (LRS), Wygen Unit I, and Walter Scott Jr. Energy Center Unit 4 (WSEC4)
    - contracted generation budgeted capital costs for MEAN's share of generating assets (see the *Capital Plan* report for detailed amounts) for participation agreements in Public Power Generation Agency (PPGA) Whelan Energy Center Unit 2 (WEC2) and Hastings Whelan Energy Center Unit 1 (WEC1). The agreement with Nebraska Public Power District (NPPD) Ainsworth Wind ended during the current fiscal year.
    - principal and interest payments on MEAN's outstanding debt (see the *Debt Service* report for detailed amounts),
    - contracted generation debt service for MEAN's share of generating assets (see the *Debt Service* report for detailed amounts)
        - PPGA WEC2 budgeted debt service net of offsets such as interest income and subsidies on Build America Bonds
        - WSEC4 Waverly assignment agreement and Louisa Generating Station (LGS) Waverly assignment agreement. The NPPD Ainsworth Wind participation agreement ended during the current fiscal year.
- Rate Offsets
    - The allocated portion of electric energy sales revenues from M-CP that relate to costs that are included in the FCRC
    - other operating revenues offset A&G costs (see the *Other Operating Revenues* report for detailed amounts)
    - budgeted investment return related to interest earnings on debt related investments offset debt service costs
- Use of Cash on Hand
    - may consist of operating and/or rate stabilization funds as needed to stabilize rates and maintain financial targets.

The FCRC is allocated to Schedules M-RP, K, and K-1 Participants based on a three-year historical average non-coincident monthly peak demand (supplied by MEAN), by Participant. A differential of plus 5% for Schedules K and K-1 Participants is maintained within the fixed cost recovery structure. The Annual Period used for the historical average non-coincident peak demand in the calculation is October – September. Therefore, the allocation for 2026-2027 includes the three years from October 2022 – September 2025.

See the Schedules of Rates and Charges for Service Schedules M, K, and K-1 included with the meeting materials for individual FCRC allocations.

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Energy Charge – Requirements Purchasers

The Energy Charge rate is calculated in accordance with the Energy Charge policy in MEAN's Financial and Administrative Policies and Guidelines. The Energy Charge is used to collect electric energy costs and any remaining budgeted costs that are not collected through MEAN's other rates and charges. A differential of plus 5% for Schedules K and K-1 Participants compared to M-RP Participants is maintained within the Energy Charge rate structure.

Green Energy Charge – Requirements Purchasers

MEAN's Green Energy Program went into effect April 1, 2023. The Green Energy Charge rate is calculated consistent with the Green Energy Charge policy in MEAN's Financial and Administrative Policies and Guidelines. The Green Energy Charge rate shall be equal to the applicable Energy Charge rate plus 5% and applicable rounding. The same differential of plus 5% for Schedules K and K-1 Participants compared to M-RP Participants maintained in the Energy Charge rate structure is maintained within the Green Energy Charge rate structure. The Green Energy Charge rate is subject to annual review and changes are approved by the MEAN Board of Directors. The Proposed Budget utilizes subscriptions in place as of December 2025 in calculating budgeted electric energy sales voluntary MWhs and related revenues. No estimate has been included for the potential Required Green Energy under the subscription confirmations and Green Energy Program Terms and Conditions.

Rates and Charges – Contract Purchasers

Rates and charges for Contract Purchasers include a Related Projects Charge, Produced Energy Cost Adjustment, and Administrative Charge. The Related Projects Charge and Produced Energy Cost Adjustment are per kilowatt-hour rates for applicable energy purchased by Contract Purchasers. The Administrative Charge consists of certain costs related primarily to the operation of MEAN and is allocated consistent with the allocation used for the FCRC. The rates and charges are calculated in accordance with the Contract Purchasers section of MEAN's Financial and Administrative Policies and Guidelines. The Proposed Budget utilizes the established Contract Demand and budget-based rates and charges in calculating budgeted electric energy sales MWhs and related revenues.

Rates and Charges – Schedule J

Rates and charges for electric energy sales under Schedule J are based on the individual terms of each Schedule J agreement.

Non-Participants

Non-participant electric energy sales revenues consist of revenues from sales of electricity to counterparties other than MEAN Participants.

In MISO and SPP, transactions occur in accordance with applicable market settlement increments. MEAN is subject to price volatility for market transactions as the market sets the $/MWh for market dependent transactions. In monthly financial statement reporting, net hourly energy transactions are evaluated on a net MWh basis to determine whether the hourly transaction should be classified as a net purchase or net sale. This hourly net settlement activity is not accounted for in the budget process, as the budget looks at activity only on a monthly basis. This disconnect between the budget process and actual accounting will result in variances from budget.

MEAN has an agreement in place to allow for increased utilization of available transmission which results in sales to East/SPP Non-Participants. To facilitate these sales, additional market purchase costs are incurred as noted in the *Purchased Power Expenses* section. Rather than budgeting for all of the highly variable gross activity, the Proposed Budget includes an estimate of net revenues related to transmission optimization on the Non-Participants RTO Markets SPP sales line.

The budget model balances loads and resources that are served outside of the RTO markets on a monthly basis. Applicable activity for budget purposes is captured in the Other Market Related Activity – West line on the *Purchased Power Expenses* report. Actual activity is recorded in accordance with applicable accounting standards.

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	Revenues				Units*	Per Unit**	
	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-	Proposed vs. Current % +/-	% +/-	Projected
Participants							
Schedule M - Requirements Purchasers (RP)							
Fixed Cost Recovery Charge (FCRC)	$ 41,991,815	$ 43,790,462	$ (1,798,647)	-4%	-3%	N/A	$ 43,790,462
Energy Charge	74,345,945	72,556,502	1,789,443	2%	-4%	7%	72,862,588
Green Energy Charge	9,279,242	8,257,892	1,021,350	12%	5%	7%	8,470,058
Total Schedule M-RP	125,617,002	124,604,856	1,012,146	1%	-3%	4%	125,123,108
Schedule M - Contract Purchasers (CP)							
Related Projects Charge	7,295,303	-	7,295,303	100%	100%	100%	-
Administrative Charge	640,872	-	640,872	100%	N/A	N/A	-
Total Schedule M-CP	7,936,175	-	7,936,175	100%	100%	100%	-
Total Schedule M	133,553,177	124,604,856	8,948,321	7%	4%	3%	125,123,108
Schedules K and K-1							
Fixed Cost Recovery Charge (FCRC)	3,708,185	3,709,538	(1,353)	0%	-5%	N/A	3,709,538
Energy Charge	768,932	731,116	37,816	5%	-2%	7%	758,942
Green Energy Charge	7,459,916	7,160,722	299,194	4%	-3%	7%	6,960,742
Total Schedules K and K-1	11,937,033	11,601,376	335,657	3%	-3%	6%	11,429,222
Schedule J							
Energy Charge	689,606	1,054,658	(365,052)	-35%	-38%	5%	1,080,294
Total Participants	**146,179,816**	**137,260,890**	**8,918,926**	**6%**	**3%**	**4%**	**137,632,624**
Non-Participants							
RTO Markets							
MISO	-	-	-	-	-	-	427,881
SPP	360,000	360,000	-	0%	-	-	4,862,843
Total RTO Markets	360,000	360,000	-	0%	-	-	5,290,724
West	-	-	-	-	-	-	191,357
Total Non-Participants	**360,000**	**360,000**	**-**	**0%**	**-**	**-**	**5,482,080**
Total Electric Energy Sales	**$ 146,539,816**	**$ 137,620,890**	**$ 8,918,926**	**6%**	**3%**	**4%**	**$ 143,114,704**

Electric Energy Sales Summary							
Participants							
Schedules M-RP, K, and K-1							
FCRC	$ 45,700,000	$ 47,500,000	$ (1,800,000)	-4%	-	-	$ 47,500,000
Energy Charge	75,114,877	73,287,618	1,827,259	2%	-4%	7%	73,621,530
Green Energy Charge	16,739,158	15,418,614	1,320,544	9%	2%	7%	15,430,800
Schedule M-CP	7,936,175	-	7,936,175	100%	100%	100%	-
Schedule J	689,606	1,054,658	(365,052)	-35%	-38%	5%	1,080,294
Total Participants	146,179,816	137,260,890	8,918,926	6%	3%	4%	137,632,624
Non-Participants	360,000	360,000	-	0%	-	-	5,482,080
Total Electric Energy Sales	**$ 146,539,816**	**$ 137,620,890**	**$ 8,918,926**	**6%**	3%	**4%**	**$ 143,114,704**
FCRC as % of Total Sales to Participants	31%	35%					35%

Units*	**Per Unit****
Demand - kW (% change shown on FCRC line for info only)	Total Schedule M/K/K-1/J - Cost per total MWh sold for info only
Energy - MWh	Total Electric Energy Sales - Cost per total MWh sold for info only

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Other Operating Revenues Narrative

Other operating revenues include the following and are categorized as an FCRC cost offset or an energy charge offset depending on the related underlying cost. Revenues that are based on administrative and general costs are part of the FCRC while revenues that relate to electric energy costs are part of the Energy Charge. Other operating revenues are also applied as cost offsets in the M-CP rates and charges, as applicable.

FCRC Cost Offsets

Administration fees - represent contracted payments to MEAN for scheduling services, market assistance agreements, and cost reimbursement under MEAN's role as Managing Agent of PPGA. Increase is due to annual escalators to these agreements and an extension of a market assistance agreement that was set to expire in the Current Budget.

Building and equipment rent - is the rent paid to MEAN by other NMPP Energy companies for use of space in the building, use of operating equipment, use of technology and shared products. Rent paid by NPGA and ACE is based on the estimated market expenses each Party would incur if each company operated independently. The allocated cost is reimbursed to MEAN as rent paid. The amount of rent paid to MEAN is reviewed and recommended by the JOC annually. As part of the budget process, the shared costs are reviewed for significant changes that would result in a change to rent other than the standard annual rate of 2%. Upon review of the shared costs, no other items were identified that would result in modifications to the rent amount. Therefore, the rent charges for NPGA and ACE were each increased by 2% as shown in the table below.

Building and Equipment Rent Paid to MEAN				
	Proposed Budget	Current Budget	vs. Current $ +/-	% +/-
NPGA	$ 84,500	$ 82,824	$ 1,676	2%
ACE	94,900	93,024	1,876	2%
Total Rent Paid to MEAN	$ 179,400	$ 175,848	$ 3,552	2%

Education - relates to revenues from various training workshops and groups. Revenues include sponsorships, registration fees, and other contracted fees.

Regulatory reporting - consists of revenues related to contracted assistance with federal and state industry reporting requirements. Increase results from updated pricing resulting from changes in reporting requirements.

Technology services – consists of revenues for equipment and managed services for data needs at solar projects. Proposed Budget includes fees for agreements currently in place.

Utility infrastructure - includes fees under contracts for Electric Distribution Services (EDS). MEAN is continuing to transition agreements under the Utility Infrastructure Program. For budget purposes, only fees for agreements with communities that are not Total Requirements Participants of MEAN were included in the Proposed Budget. As MEAN continues to evaluate this service offering, some agreements with non-MEAN communities may be terminated.

Energy Charge Cost Offsets

Reactive power - relates to ownership of Wygen Unit I and is received monthly.

Sales of excess capacity – relates to revenues from sales of a portion of capacity in the MISO market's annual auction. Quantity available and rate received varies year to year and therefore is not included in the annual budget.

Transmission Revenue – as a transmission owner, MEAN recovers its revenue requirement associated with its transmission facilities in MISO through transmission rates under the applicable Schedules of the MISO Tariff. Due to final review of proper accounting treatment, this revenue was reclassed from a credit in Transmission Expenses to Other Operating Revenues.

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	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-	Projected
Other Operating Revenues					
Administration fees	$ 471,048	$ 430,958	$ 40,090	9%	$ 463,854
Building and equipment rent	179,400	175,848	3,552	2%	175,848
Education	41,546	42,554	(1,008)	-2%	55,085
Other - FCRC	-	-	-	-	15,500
Regulatory reporting	94,500	79,000	15,500	20%	88,750
Technology services	12,000	-	12,000	100%	30,658
Utility infrastructure	13,500	13,500	-	0%	41,467
Other - Energy	-	-	-	-	59
Reactive power	62,700	58,698	4,002	7%	54,077
Sales of excess capacity	-	-	-	-	842,126
Transmission revenue	1,602,720	1,543,650	59,070	4%	1,560,351
Total Other Operating Revenues	**$ 2,477,414**	**$ 2,344,208**	**$ 133,206**	**6%**	**$ 3,327,775**
Total FCRC Cost Offsets in Other Operating Revenues	$ 811,994	$ 741,860	$ 70,134	9%	$ 871,162
Total Energy Charge Cost Offsets in Other Operating Revenues	$ 1,665,420	$ 1,602,348	$ 63,072	4%	$ 2,456,613

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Purchased Power Expenses Narrative
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Purchased Power Expenses

Purchased power expenses are detailed on the *Purchased Power Expenses* report and consist of electric energy costs incurred for energy and capacity provided by contracted generation through assignment agreements, participation agreements and power purchase agreements. Depending on the terms of the agreement, costs may include a contracted price for each MWh generated, actual cost for each MWh generated, contracted share of debt service, capital, operations and maintenance (O&M), and administrative and general (A&G). The quantity purchased also varies by contract and may include a set amount or a percentage share of MWhs generated. Costs related to market activity are also included in Purchased Power expenses.

MEAN's agreements allow Participants to keep their individual WAPA allocations. This activity is incurred by MEAN as agent, passed through to individual Participants, and reported net in MEAN's financial statements. MEAN's Renewable Distributed Generation Policy allows Participants to contract for a maximum level of renewable distributed generation resources. The following table describes these Participant power supply resources. The renewable distributed generation resources reduce the amount of energy supplied by MEAN. Actual generation from these resources impacts the MWh sold by MEAN to these Participants. Purchased power expenses are also impacted by reducing purchases for load in MISO and SPP.

Participant Resources	Fuel Type	Proposed Budget	Current Budget
		Capacity (MW)*	
WAPA - Participant Allocations	Hydroelectric	107.1	109.8
Distributed Generation Community Solar Projects	Solar	19.8	21.4

*Capacity shown represents the maximum amount expected under contracts or expected contract terms at the time the budget was prepared. The capacity may not apply for the entire fiscal year due to contract start and end dates, final agreements, and actual vs. expected commercial operation dates for development projects. Solar projects shown as Alternating Current (AC) capacity.

Contracted Purchases

Each resource is budgeted based on the contract terms and information provided by the plant operators. Budgets provided by plant operators are often on a twelve-month period other than MEAN's fiscal year. For periods not included in the budget provided, MEAN estimates costs based on the budget provided plus an estimated percentage increase.

When applicable, estimated MWh production utilized in the budget is determined using a wholesale electric production cost model. This model generates 700 scenarios of possible outcomes, from which the mean or expected scenario is utilized. Each scenario captures various potential outcomes, such as changes in market power and fuel prices, generator unplanned outages, load variations, and other market-driving factors that can impact power costs. Available capacity is determined according to season of year, time of day, planned maintenance, forced outage rates, and variable fuel costs. Availability of existing resources is modeled on historical operating data, unit minimums, and planned outage schedules. The related variable cost is then applied to this quantity to estimate the expected expense.

Variances will result from actual vs. estimated economic generation and actual operating capability. Lower MWh generation due to operating capability may save on fuel costs but often result in additional operation and maintenance expenses at these facilities and from differences in timing related to capital projects. An outage schedule is provided by plant operators; however, plants experience unplanned outages, planned outages may be extended, and/or the timing of planned outages may change, all of which result in variances between actual results and budget. Variances in actual economic dispatch of facilities compared to budget also impacts amounts paid under contracted purchases. Certain agreements include charges when production is reduced as a result of economics resulting in curtailment costs. As a result, even when production is lowered, MEAN may not necessarily save on costs.

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The following table shows power supply resources which are classified as contracted purchases and for which MEAN expects to receive capacity during the budget years.

Unit Name	Fuel Type	Region	Proposed Budget Capacity (MW)*	Current Budget Capacity (MW)*
Hastings WEC1	Coal	SPP - East	5.3	5.3
PPGA WEC2	Coal	SPP - East	80.0	80.0
WSEC4 Waverly Assignment	Coal	MISO	3.2	3.2
Louisa Waverly Assignment	Coal	MISO	8.2	8.2
BHP NS CT #1	Natural Gas	SPP - West	15.0	15.0
HCPD Wessington Springs Wind	Wind	SPP - East	10.0	10.0
Kimball Wind PPA	Wind	SPP - West	30.0	30.0
NPPD Ainsworth Wind	Wind	SPP - East	-	7.0
NPPD Crofton Bluffs Wind	Wind	SPP - East	4.0	4.0
NPPD Elkhorn Ridge Wind	Wind	SPP - East	8.0	8.0
NPPD Laredo Ridge Wind	Wind	SPP - East	8.0	8.0
Sandhills Solar - Alliance	Solar	SPP - East	5.4	5.4
Sandhills Solar - Sidney	Solar	SPP - West	2.2	2.2
Sandhills Solar - Gering	Solar	SPP - West	2.9	2.9
Sandhills Solar - Fort Morgan	Solar	SPP - West	7.0	7.0
Sandhills Solar - Yuma	Solar	SPP - West	2.3	2.3
Landfill Gas Project	Landfill Gas	MISO	4.8	4.8
Aspen/Ridgway Hydropower	Hydroelectric	SPP - West	5.4	5.4
CNPPID Johnson Hydro Facilities	Hydroelectric	SPP - East	42.7	42.7
DMEA Shavano Falls	Hydroelectric	SPP - West	7.6	7.6
WAPA LAP - MEAN	Hydroelectric	SPP - West	6.6	6.6
WAPA Tribe Contracts	Hydroelectric	SPP - West	8.0	8.0
WAPA Displacement Agreement	Hydroelectric	SPP - West	70.1	69.7
Participant Committed Facilities	Oil/Gas	MISO	30.0	30.0
Participant Committed Facilities	Oil/Gas	SPP - East	43.5	50.4
Participant Committed Facilities	Oil/Gas	SPP - West	8.4	9.4
Capacity Purchases	Oil/Gas	MISO	40.0	40.0
Capacity Purchases	Oil/Gas	SPP - East	25.0	-
Capacity Purchases	Oil/Gas	SPP - West	20.0	-

*Capacity shown represents the maximum amount expected under contracts or expected contract terms at the time the budget was prepared. The capacity may not apply for the entire fiscal year due to contract start and end dates, final agreements, seasonal availability, and actual vs. expected commercial operation dates for development projects. Contracted capacity may differ from the accredited capacity. Solar projects shown as Alternating Current (AC) capacity.

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The following provides further information for significant agreements and/or larger fluctuations year to year.

Hastings WEC 1 – expected MWh production and fuel $/MWh has decreased resulting in an overall decrease in expected fuel costs. Increased O&M costs and decreased A&G costs contribute to an increase in overall $/MWh for this unit. Capital costs are steady year to year. See also the *Capital Plan* section.

PPGA WEC 2 – through Public Power Generation Agency (PPGA), MEAN has an ownership interest in PPGA Whelan Energy Center (WEC) 2. The agreement is structured such that it qualifies as a contracted purchase and thus MEAN's share of the productive capacity net value and related debt is not reflected on MEAN's balance sheet. MEAN's annual share of debt and capital costs are recorded as purchased power expenses. O&M costs are anticipated to increase due to increased turbine/generator outage costs. Capital costs increase due to changes in project scope, cost estimates, and timing from year to year. See also the *Capital Plan* section. Debt service costs increase due to lower expected debt service related interest income, which offsets debt service costs. See also the *Debt Service* report. A&G is less than Current Budget due to decreased outside services costs. Expected MWh production fluctuates annually due primarily to expectations related to economic dispatch of the unit.

Walter Scott, Jr. Energy Center (WSEC) 4 Waverly Assignment – see WSEC 4 explanation in *Production* section for information on expected generation and operating costs. Debt costs increase slightly each year as shown on the *Debt Service* report.

Louisa Waverly Assignment – increased MWh generation due to economics offset slightly by decreased coal costs result in increased fuel costs. O&M costs increase due to upward cost pressure in multiple O&M cost categories. Debt costs increase over the next few years before declining as shown on the *Debt Service* report. The budget provided by Mid-American for 2026 was assembled in the fall of 2024. MEAN anticipates receiving a final budget later in December.

Black Hills NS CT#1 – no change in MWh generation however an increase in the contracted $/MWh results in an overall increase in contracted energy costs. Although this resource is located outside the SPP market, it's brought into the SPP-West market to serve MEAN load. See the *Transmission* section for related costs.

Heartland Consumers Power District (HCPD) Wessington Springs Wind – a contracted annual increase in $/MWh and an increase in anticipated compensable curtailment costs results in overall increased costs at a higher $/MWh.

Kimball Wind Purchased Power Agreement (PPA) – a contracted annual increase in $/MWh result in an increase in contracted energy costs.

NPPD Ainsworth Wind – contract ended September 30, 2025 resulting in decreased costs when compared to Current Budget.

NPPD Crofton Bluffs Wind, NPPD Elkhorn Ridge Wind, NPPD Laredo Ridge Wind – no change in MWh generation; however contracted increase in $/MWh results in an overall increase in contracted energy costs. A&G costs increased due to an increase in overall anticipated curtailment costs.

Sandhills Solar Projects – Current Budget generation was based on estimated commercial operation dates and did not necessarily include a full year of generation at some locations. All facilities are expected to be operational for the full Proposed Budget year. As a result, increased MWh generation and contracted increase in $/MWh results in increased contracted energy costs. Facilities are in SPP – East and SPP – West and are treated as behind the meter, decreasing purchases for load from SPP.

Landfill Gas Project – decreased anticipated MWh generation which is more consistent with recent actuals results in decreased contracted energy costs.

Aspen/Ridgway Hydro Power – increased total MWh generation including impact of seasonal production and related pricing increases the total overall budgeted contracted energy costs. The budgeted $/MWh is impacted by the seasonal production changes and the contracted annual increase. Final budgeted MWh generation included is less than the MWh used in the December meeting materials. The final budgeted MWh generation is more consistent with historical data and resulted in lower contracted energy costs compared to what had been included in December.

Central Nebraska Public Power and Irrigation District (CNPPID) Johnson Hydro Facilities – this agreement includes different rates for on-peak and off-peak generation. While overall expected production is consistent between years, Proposed Budget anticipates an increase in off-peak MWh generation based on actual results this fiscal year, resulting in decreased contracted energy costs. The decrease is offset in part by increased O&M costs.

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Delta-Montrose Electric Association (DMEA) Shavano Falls – a contracted annual increase in $/MWh results in an overall increase in contracted energy costs.

Western Area Power Administration (WAPA) LAP - MEAN – increased WAPA energy and capacity rates result in an overall increase in $/MWh.

WAPA Tribe Contracts – increased WAPA rates and decreased contracted energy $/MWh result in an overall decrease in costs.

WAPA Displacement Agreement – under the terms of the WAPA Displacement Agreement, MEAN pays for contracted MWh at SPP – East market prices for WAPA energy delivered to MEAN in SPP – West. Although pricing is variable resulting in larger fluctuations year to year, the overall cost of the energy is competitive. Forecasted electric energy market prices are higher than prices in the Current Budget resulting in an increase in total budgeted costs for the WAPA Displacement Agreement. While the majority of the increase compared to Current Budget is due to the pricing variability, the Proposed Budget also includes costs to purchase renewable energy certificates related to the agreement. This option was not previously available and therefore these costs were not included in either the Current Budget or in the costs in the information provided in the December meeting materials.

Participant Committed Facilities – capacity payments for all facilities increase from $2.50/kW/month to $3.00/kW/month, subject to approval by the MEAN Board of Directors. Payments to Participants for accredited generation facilities committed to MEAN are outlined in the applicable Schedule of Rates and Charges. Proposed Budget includes anticipated decrease in total quantity of Contract Capacity. This decrease is offset by the increased rate resulting in an overall increase in costs. Additionally, registration of Participant Committed Facilities located in SPP has resulted in increased MWh generation due to being called on by SPP. This results in increased costs for energy production.

Capacity Purchases – MEAN has entered into agreements to purchase additional capacity from Indianola, IA and Waverly, IA to meet market requirements. Costs are increasing as this rate is tied to the rate paid for Participant Committed Facilities which is expected to increase as noted above. Additionally, due to Resource Adequacy and Planning Reserve Margins in SPP – East and SPP – West, an additional 25 MW is budgeted in SPP – East and 20 MW is budgeted in SPP – West. These additional purchases are budgeted based on current estimates of expected contract costs. The increase in quantity needed as a result of these market changes significantly increases overall costs.

Participant Distributed Generation Purchases – an increase in the standard avoided cost rate for these energy only purchases resulted in an increase in costs. See *Other Rates and Charges - Avoided Cost and Standard Rate Narrative* section for rate information. Total MWh purchased under these agreements is also expected to increase slightly.

Energy Purchases – increase in firm energy purchase costs due to annual increase in contracted $/MWh.

<u>Market Activity</u>
In MISO, SPP – East, and the expanded SPP – West markets, MEAN must bring sufficient capacity to each market related to load. As a result, MEAN must pay for energy generated under the terms of MEAN's applicable power contracts. In addition, under the terms of the markets, MEAN must sell energy generated by MEAN's owned and contracted generation into each respective market resulting in "generation sales revenues received" (see Generation Sales Revenues Received for MISO and SPP on the *Purchased Power Expenses* report and in this section). To serve MEAN's Participant load within MISO and SPP, MEAN must also "purchase for load" the energy needed to serve MEAN's Participant load from the respective market (see Purchases for Load for MISO and SPP on the *Purchased Power Expenses* report and in this section).

The markets add a layer of uncertainty in energy costs. MEAN is subject to both usage variances and price volatility for market transactions as the market sets the $/MWh for market dependent transactions. Variances in actual Participant load vs. budgeted load result in variances in quantities of energy purchased from the markets. Variances in actual generation output by resources vs. budgeted generation output result in variances in quantities of generation sales revenues received.

Market prices vary greatly depending on the actual resources generating in the market, impact of wind, weather, loads, peak vs. off peak pricing, and congestion. As part of MEAN's agreement with The Energy Authority (TEA), TEA assists with Locational Marginal Price (LMP) forecasting. TEA implements a custom in-house forward curve forecasting methodology that utilizes broker marks, Intercontinental Exchange (ICE) curves, New York Mercantile Exchange (NYMEX), historical hourly profiles, 3rd party forward curves, and other market sources as inputs to drive LMP modelling.

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TEA provided MEAN with LMP prices on a monthly basis for each resource node and load node in MISO and SPP. Ongoing market price volatility poses challenges budgeting for financial activity in wholesale electric markets, driven by numerous factors including fluctuating natural gas prices, addition of renewable resources within the markets, wind variability, weather conditions, transmission constraints, and resources outages. Additionally, budgeting for the expanded transactions in SPP without any historical data brings an additional layer of uncertainty.

The market prices utilized in the December Committee and January meeting materials were based on information provided by TEA as of December 3, 2025.

The following provides further information for significant components of Market Activity and/or larger fluctuations year to year.

Purchases for Load – budgeted MWhs are dependent on budgeted load for MEAN Participants within the applicable market and expected MWh generation from resources such as behind the meter resources including MEAN and community owned solar facilities. Generation by behind the meter resources reduce MEAN's required MWh purchases for load.

- **MISO –** budgeted MWh load purchases are less than Current Budget. However, the expected market driven pricing $/MWh is greater than Current Budget resulting in a significant increase in budgeted energy expense.
- **SPP –** budgeted MWh load purchases in the East area are slightly less than Current Budget. However, the expected market driven pricing $/MWh is greater than Current Budget resulting in an increase in budgeted energy expense for the East area. The overall increase comes from the expanded market resulting in new transactions for load purchases for communities located in the expanded market area. The Proposed Budget anticipates the market driven pricing $/MWh in the West area to be greater than the East area.

Generation Sales Revenues Received – budgeted MWhs relate directly to budgeted generation MWhs for the applicable generation resources within each market area. See the *Purchased Power Expenses* section and *Production Expenses* section for information on expected generation.

- **MISO** – budgeted net MWh generation for facilities in MISO (WSEC4, WSEC4 Waverly Assignment and Louisa Waverly Assignment) is anticipated to increase between years. The expected $/MWh paid by the market for the generation is also increasing. These two factors result in a significant overall increase in expected generation sales revenues received.
- **SPP** – budgeted net MWH generation for facilities in the SPP – East area (LRS Unit 1, Hastings WEC1, PPGA WEC2, HCPD Wessington Springs, various NPPD Wind facilities, and CNPPID Johnson Hydro Facilities) is anticipated to increase between years. The expected $/MWh paid by the market for the generation is also increasing. These two factors result in a significant increase in expected generation sales revenues received for the East area. The overall increase comes from the expanded market area. Effective April 1, 2026, Wygen Unit I, LRS Units 2 and 3, BHP NS CT #1, Kimball Wind PPA, Aspen/Ridgway Hydropower, DMEA Shavano Falls, WAPA Displacement Agreement, and the contract supporting the Energy Purchases will be settled in the SPP - West area resulting in MEAN's receipt of revenues from the market. The Proposed Budget anticipates the market driven pricing $/MWh in the West area to be consistent with the pricing used for the load purchases. Until more history exists, the inherent market congestion has not been factored into this item nor has a budget for Financial Instruments been included. Changes from the December meeting materials include a decrease in estimated MWh generation from Aspen/Ridgway Hydro Power and lower estimated $/MWh paid by the market for certain resources resulting in a decrease in estimated generation sales revenues received compared to the information presented in December.

Financial Instruments – financial instruments include MISO Financial Transmission Rights (FTR) and Auction Revenue Rights (ARR) and SPP Transmission Congestion Rights (TCR) and ARRs. These financial instruments serve as a hedge against marginal congestion cost within the related Locational Marginal Pricing (LMP) for market purchases for load and generation sales revenues received. As part of MEAN's agreement with TEA, TEA manages MEAN's participation in financial instruments. TEA provided MEAN with budgeted financial instrument dollars for the Proposed Budget for MISO and the SPP-East area. As noted above, information is not available to provide a budget for the SPP – West area. TEA forecasts auction strategies (including an annual payback) related to the ARR by looking at historical performance data to arrive at budgeted dollars. Activity varies based on many external factors and variances are expected. Financial Instruments are included in *Purchased Power Expenses* as the financial settlement either offsets or adds to Purchased Power - Market Activity costs.

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Other Market Related Activity –

- **MISO** – the projected activity results from the actual MISO market purchases made for sale to non-Participants in the SPP market. These transactions optimize available transmission. As the activity is highly variable, the gross revenues and costs are not budgeted. See the *Electric Energy Sales - Non-Participants* section for information on the estimate of net revenues included in the Proposed Budget.
- **SPP** – for Contract Purchasers, MEAN doesn't purchase the Contract Purchaser's load from the market, rather MEAN financially delivers the fixed energy quantity established by the Legacy SSM Agreement. MEAN is charged by the market for that energy delivery at the applicable market price. Final estimated $/MWh resulted in decreased costs compared to the information presented in December.
- **West** – this activity relates to balancing of loads of Participants and actual generation from contracted and owned generation resources. The cost is also impacted by the actual prices and financial settlements related to energy imbalances. The majority of this activity will be replaced by the activity that occurs in the expanded SPP market.

Units Reconciliation

The budget process includes a reconciliation to compare budgeted Participant loads against budgeted energy purchases, on a monthly basis.

In the MISO and SPP markets, the budgeted MWhs for purchases for load reconciles against the budgeted MWhs needed to serve applicable Participant load. In SPP this is done separately for the East and West areas. The budgeted load MWh is net of any behind the meter and/or other applicable generation.

In a similar manner, budgeted MWh for generation sales revenues received reconciles against the expected MWh production from the units registered in MISO and separately for the East and West SPP areas.

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	Expenses				MWh	$/MWh	
	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-	Proposed vs. Current % +/-	% +/-	Projected
Contracted Purchases							
FCRC Costs	$ 153,594	$ 155,160	$ (1,566)	-1%		23%	$ 145,428
Energy Charge Costs	1,163,405	1,257,808	(94,403)	-8%		15%	1,190,582
Hastings WEC1	1,316,999	1,412,968	(95,969)	-7%	-20%	16%	1,336,010
FCRC Costs	15,029,313	14,260,410	768,903	5%		-9%	15,580,668
Energy Charge Costs	12,332,761	12,052,401	280,360	2%		-12%	13,046,246
PPGA WEC2	27,362,074	26,312,811	1,049,263	4%	16%	-10%	28,626,914
FCRC Costs	338,418	333,570	4,848	1%		-14%	333,569
Energy Charge Costs	407,300	460,669	(53,369)	-12%		-25%	463,153
WSEC4 Waverly Assignment	745,718	794,239	(48,521)	-6%	18%	-20%	796,722
FCRC Costs	878,166	865,584	12,582	1%		-15%	865,586
Energy Charge Costs	1,490,547	1,216,569	273,978	23%		2%	1,424,218
Louisa Waverly Assignment	2,368,713	2,082,153	286,560	14%	20%	-5%	2,289,804
BHP NS CT #1	7,664,582	7,548,482	116,100	2%	0%	2%	7,317,003
HCPD Wessington Springs Wind	1,960,572	1,912,570	48,002	3%	0%	3%	1,973,010
Kimball Wind PPA	3,506,538	3,437,527	69,011	2%	0%	2%	3,354,336
FCRC Costs	-	482,664	(482,664)	-100%		-	426,748
Energy Charge Costs	-	299,199	(299,199)	-100%		-	300,361
NPPD Ainsworth Wind	-	781,863	(781,863)	-100%	-100%	-100%	727,109
NPPD Crofton Bluffs Wind	1,170,272	1,131,925	38,347	3%	0%	3%	1,012,001
NPPD Elkhorn Ridge Wind	2,033,739	1,882,712	151,027	8%	0%	8%	1,733,666
NPPD Laredo Ridge Wind	2,438,688	2,294,191	144,497	6%	0%	6%	2,139,833
Sandhills Solar Projects							
Alliance	587,980	549,937	38,043	7%	6%	1%	292,644
Sidney	237,768	235,545	2,223	1%	0%	1%	149,969
Gering	312,127	290,040	22,087	8%	6%	1%	193,137
Fort Morgan	747,844	124,634	623,210	500%	500%	0%	124,634
Yuma	246,504	172,775	73,729	43%	42%	0%	86,567
Landfill Gas Project	2,240,715	2,345,186	(104,471)	-4%	-4%	0%	2,302,994
Aspen/Ridgway Hydropower	476,556	449,790	26,766	6%	4%	2%	475,567
Central Nebraska Public Power Irrigation District (CNPPID)							
Johnson Hydro No. 1	2,956,538	2,980,284	(23,746)	-1%	0%	-1%	2,860,401
Johnson Hydro No. 2	3,279,621	3,292,603	(12,982)	0%	0%	0%	3,230,299
DMEA Shavano Falls	2,455,400	2,439,824	15,576	1%	0%	1%	2,554,111
WAPA LAP - MEAN	678,261	633,769	44,492	7%	0%	7%	633,766
WAPA Tribe Contracts	1,300,427	1,322,499	(22,072)	-2%	0%	-2%	1,322,628
WAPA Displacement Agreement	10,436,252	9,282,875	1,153,377	12%	0%	12%	8,581,619
WAPA - Other	-	6,000	(6,000)	-100%	-44%	-100%	11,899
Participant Committed Facilities	3,301,674	2,840,956	460,718	16%	-8%	26%	2,651,276
Capacity Purchases	4,197,500	1,160,000	3,037,500	262%	-	-	1,160,000
Participant Distributed Generation Purchases	20,575	16,390	4,185	26%	3%	22%	17,606
Energy Purchases	2,656,200	2,613,120	43,080	0%	0%	2%	2,613,120
Total Contracted Purchases	**86,699,837**	**80,347,669**	**6,352,168**	**8%**	**5%**	**3%**	**80,568,649**

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	Expenses				MWh	$/MWh	
	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-	Proposed vs. Current % +/-	% +/-	Projected
Market Activity							
Purchases for Load							
MISO	15,377,051	10,296,132	5,080,919	49%	-2%	53%	13,447,699
SPP	57,584,766	28,646,890	28,937,876	101%	70%	18%	27,060,860
Total Purchases for Load	72,961,817	38,943,022	34,018,795	87%	48%	26%	40,508,559
Generation Sales Revenues Received							
MISO	(18,287,298)	(10,631,814)	(7,655,484)	72%	16%	48%	(10,757,286)
SPP	(56,169,503)	(23,278,121)	(32,891,382)	141%	97%	23%	(22,555,302)
Total Generation Sales Revenues Received	(74,456,801)	(33,909,935)	(40,546,866)	120%	71%	28%	(33,312,588)
Financial Instruments							
MISO	(462,374)	(678,338)	215,964	-32%			(192,679)
SPP	(3,522,479)	(2,791,568)	(730,911)	26%			(3,426,023)
Total Financial Instruments	(3,984,853)	(3,469,906)	(514,947)	15%			(3,618,702)
Other Market Related Activity							
MISO	-	-	-	-	-	-	4,015,572
SPP	5,443,936	-	5,443,936	100%	100%	100%	68,329
West	-	(77,511)	77,511	-100%	-100%	-100%	2,884,617
Total Other Market Related Activity	5,443,936	(77,511)	5,521,447	-7123%	-430%	2029%	6,968,519
Total Market Activity	**(35,901)**	**1,485,670**	**(1,521,571)**	**-102%**	**-114%**	**-83%**	**10,545,788**
Total Purchased Power Expenses	**$ 86,663,936**	**$ 81,833,339**	**$ 4,830,597**	**6%**	**-47%**	**100%**	**$ 91,114,437**
Total FCRC Costs in Purchased Power	$ 16,399,491	$ 16,097,388	$ 302,103	2%			$ 17,351,999
Total Energy Charge Costs in Purchased Power	$ 70,264,445	$ 65,735,951	$ 4,528,494	7%			$ 73,762,437

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Production Expenses
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	Expenses				MWh	$/MWh	
	Proposed Budget	Current Budget	Proposed vs. Current		Proposed vs. Current		
			$ +/-	% +/-	% +/-	% +/-	Projected
Owned Generation							
Wygen Unit I	$ 5,636,464	$ 5,593,574	$ 42,890	1%	2%	-2%	$ 5,106,769
LRS Unit I	1,673,097	1,668,759	4,338	0%	-5%	6%	1,497,669
LRS Unit 2 and Unit 3	3,656,601	3,838,366	(181,765)	-5%	-15%	12%	3,358,068
WSEC 4	7,198,822	8,120,659	(921,837)	-11%	18%	-25%	7,840,468
Total Production Expenses	**$ 18,164,984**	**$ 19,221,358**	**$ (1,056,374)**	**-5%**	**5%**	**-10%**	**$ 17,802,974**

Production Expenses Narrative

Production expenses consist of electric energy costs for generation owned by MEAN. These expenses represent costs incurred in the ongoing operation of the facility and in the production of energy.

MEAN has ownership interests in Wygen Unit I, Laramie River Station (LRS), and Walter Scott Jr. Energy Center Unit 4 (WSEC 4), all of which are coal-fired. The productive capacity net value of each facility and any related debt is reflected on MEAN's Balance Sheet. As a result, debt service and capital costs are not included in Production Expenses. See the *Capital Plan* and *Debt Service* sections for more information.

Wygen Unit I (20.0 MW capacity located in SPP – West) – increases in MWh generation and coal costs result in increased fuel costs. O&M costs are greater due to increased lime costs. A&G costs are less due to decreased services cost. Overall, costs increased while $/MWh is less than Current Budget. Although this resource is located outside the SPP market, it will be pseudo-tied into into the SPP-West market. See the *Transmission* section for related costs. Resource operator provided final 2026 budget information resulting in increased overall costs compared to information presented in December.

LRS Unit 1 (9.9 MW capacity located in SPP – East) – decreased MWh generation but increased coal costs result in an overall slight decrease in fuel costs. Decreased boiler plant maintenance lowers O&M costs. This results in an overall decrease in costs, but at a greater $/MWh.

LRS Units 2 and 3 (18.6 MW capacity located in SPP – West) – decreased MWh generation but increased coal costs resulted in an overall decrease in fuel costs. O&M costs increased compared to Current Budget offset in part by lower A&G costs. This results in an overall decrease in costs, but at a greater $/MWh. Resource operator provided final 2026 budget information resulting in increased overall costs compared to information presented in December.

WSEC 4 (56.0 MW capacity located in MISO) – increased MWh generation based on estimated economic dispatch and planned outage offset in part by lower coal costs lead to an overall increase in fuel costs. O&M costs decrease due to lower maintenance of boiler plant costs. Total costs and overall $/MWh are decreasing year over year. The budget provided by Mid-American for 2026 was assembled in the fall of 2024. A final budget was not received prior to the deadline for finalizing MEAN's budget.

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Transmission Expenses Narrative
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Transmission Expenses

Transmission expenses consist of costs to move MWhs across the electric grid. MEAN's transmission agreements include Network Integration Transmission Service (NITS) contracts that are based on applicable peak load (load ratio share as defined by the tariff) and Point-to-Point (PTP) agreements where MEAN pays a set amount to reserve rights to move power between two specific points on a transmission system regardless of actual usage. Pooled transmission costs relate to transmission of power, purchased by MEAN or produced by a MEAN generation resource, from one transmission system to another and the ability to utilize resources between markets. Transmission costs incurred by MEAN as agent for Participants are passed through to individual Participants and reported net in MEAN's financial statements. The *Transmission Expenses* report includes only the pooled transmission costs incurred and reported by MEAN.

The following provides further information for significant agreements and/or larger fluctuations year to year.

Network (NITS) – factors that change NITS year over year include changes in zonal peaks, rates, and transmission expense offsets. NITS are also impacted by the expansion of the SPP market. A grandfathered transmission credit received from NPPD for transmission related to LRS ends February 2026 therefore credits are not included in the Proposed Budget (not Section 30.9 related). The expansion of the SPP market brings changes to available strategies to serve various loads in SPP. Current Budget amounts are resource related as transmission allows for utilization of resources between markets in serving loads on the SPP/West border. These amounts are eliminated with the expanded SPP market. The Proposed Budget amount is resource related as transmission allows for serving load physically located outside of the SPP market. Additional analysis since December resulted in lower estimated costs compared to information included in the December materials.

Point-to-Point Long-Term

- **MISO –** increased rates and charges result in increased costs. Transmission path allows MEAN to utilize WSEC4 capacity to satisfy SPP Resource Adequacy requirements.
- **WAPA - SLCA** – amounts are related to the Aspen/Ridgway Hydro Power facility. The SPP market expansion eliminates the need for this path.
- **West Resource Related –** increased rates and charges result in increased costs. Transmission is needed for Wygen Unit I and BHP NS CT #1.

Point-to-Point Short-Term – short-term transmission purchases were used on an as-needed basis primarily in the West. With the SPP market expansion these short term purchases are no longer needed.

Operating Reserves – operating reserve is the excess amount of online generation capacity available to respond to sudden load changes or loss of a generator. As operating reserves are ancillary services tied to transmission and are typically identified under the counterparty's applicable Open Access Transmission Tariff the cost is classified in transmission expense. Proposed Budget has a decrease in costs due to the expanded SPP market removing the need to carry operating reserves in the Western Area Colorado Missouri (WACM) balancing area. Operating reserves are still needed to serve loads in the Public Service Company of Colorado (PSCo) balancing area and are included in the Proposed Budget.

Resource Related – resource related transmission charges relate to resource specific charges that are not point to point paths. This can mean transmission costs to get power to the grid or transmission taxes. Proposed Budget increased due to additional transmission charges incurred as a result of the various Sandhills Solar Projects MEAN has under contract.

Other – includes anticipated transmission study costs. Decrease from Current Budget due to ancillary transmission costs that will no longer be incurred with the expanded SPP market.

Transmission Credits – MEAN expects to be able to recover its revenue requirement associated with its West-side LRS Units 2 and 3 transmission facilities through SPP's tariff. The Proposed Budget is based on preliminary estimates.

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Transmission Expenses
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	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	Proposed vs. Current % +/-	Projected
Transmission					
Network (NITS)	$ 1,908,660	$ 503,694	$ 1,404,966	279%	$ 556,734
Point-to-Point Long-Term (PTP-LT)					
MISO	3,791,436	3,567,070	224,366	6%	3,652,925
WAPA - SLCA	-	63,709	(63,709)	-100%	106,603
West Resource Related	2,053,379	2,034,583	18,796	1%	2,024,470
Total Point-to-Point Long-Term	5,844,815	5,665,362	179,453	3%	5,783,998
Point-to-Point Short-Term (PTP-ST)	-	46,692	(46,692)	-100%	52,044
Operating Reserves	226,562	1,178,001	(951,439)	-81%	1,151,331
Resource Related	469,670	236,511	233,159	99%	298,460
Other	30,000	39,528	(9,528)	-24%	57,928
Total Transmission	**8,479,707**	**7,669,788**	**809,919**	**11%**	**7,900,494**
Transmission Credits	**(100,000)**	**-**	**(100,000)**	**100%**	**-**
Total Transmission Expenses	**$ 8,379,707**	**$ 7,669,788**	**$ 709,919**	**9%**	**$ 7,900,494**

All Transmission Expenses are in the Energy Charge.

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Capital Plan Narrative
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Capital Plan

Timing of capital purchases and additions may vary significantly from budget due to a number of factors. Budgets for productive capacity capital and contracted generation capital are developed by plant operators. The timing of projects is often dependent on the operating conditions of the plant and may be started early or delayed. Capital expenditures may arise from a range of factors, including essential preventative maintenance to ensure longevity and reliability, strategic additions or upgrades aimed at enhancing overall performance and efficiency, and compliance with evolving environmental regulations necessitating the adoption of cleaner technologies and emission control systems. These investments are crucial for sustaining reliable energy production while meeting modern standards and operational demands.

MEAN Capital

Items are expensed or capitalized based on the capitalization policy (items individually exceeding $10,000 and having an expected useful life of more than one year). Timing of capital items may vary from budget due to several factors. At the time the budget is prepared, costs may be based on early estimates of identified needs. These estimates may not include actual quotes or bids from potential vendors. The timing of projects is often dependent on the workload of staff and may be started early or delayed.

The proposed NMPP Energy capital plan is presented for building and technology infrastructure related items utilized by all NMPP Energy companies as well as items specific to MEAN. Staff works to develop estimates of capital purchases and additions for an additional five fiscal years to present an anticipated multi-year capital plan. Costs and timing noted in preliminary fiscal years are based on costs for recent projects or purchases and the estimated useful lives. These projects may not necessarily occur in the year noted and are subject to future review by the JOC and approval by the respective company Board of Directors. See the *NMPP Energy – Capital Plan* report for more detail.

Costs related to shared capital assets are considered when determining the amount of rent charged by MEAN to the other companies. Capital asset purchases for items that would be shared by all NMPP Energy companies are reviewed with the Finance Committee at the October 2025 meeting.

- **Shared Items** - the Proposed Budget includes the following:
  - **Heat Pump Replacements** – due to the age of the Glynoaks building, there have been ongoing maintenance issues with the heat pumps. Staff is working with outside vendors to develop a plan for replacement. The tentative plan is to replace in phases over multiple years as shown on the report.
  - **Jace Controller for Heat Pumps/Honeywell WEBs Server** – the Proposed Budget also includes replacement of the overall control unit for the heat pump system controls which must be replaced periodically.
- **MEAN** - the Proposed Budget includes the following:
  - **Electrical Distribution O&M Vehicle.** Replacement of vehicles is on a rotating basis. The Electrical Distribution O&M vehicle has a 3-year life and was last purchased in June 2023.
  - **DSG/Telemetry Vehicle.** The current vehicle does not meet the needs of DSG and telemetry team. Replacement of vehicles is on a rotating basis, and the current vehicle was purchased in 2014. The DSG/Telemetry Vehicle is expected to have a longer life based on expected annual miles driven.

Owned Generation Capital (Productive Capacity)

See the *Capital Plan* report for expected cash outlay for MEAN's share of costs obtained from capital budgets provided by plant operators. As the capital budgets provided are not on the same fiscal year as MEAN's, estimating when the actual cash outlay will occur is difficult and likely to vary from budget. Variances from budget and year-to-year are expected due to changes in project scope, cost estimates, and timing.

- **Wygen Unit I** – major projects include air dryer upgrades, selective catalytic reduction, live rotor flux monitoring, and reactive work. Resource operator provided final 2026 capital budget resulting in decreased costs.
- **LRS Units 1, 2, & 3** – major projects include multiple 345kV transmission equipment upgrades, and multiple 480V scrubber switchgear replacements. Resource operator provided final 2026 capital budget resulting in decreased costs.
- **WSEC 4** – the only major project is adding natural gas igniters.

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Contracted Generation Capital

See the *Capital Plan* report for capital costs included within Purchased Power expenses for contracted generation under participation agreements which require MEAN to pay for the applicable participation share of capital and debt service. As MEAN does not own the related generation, the capital costs are recorded as expenses in the year incurred. Variances from budget and year-to-year are expected due to changes in project scope, cost estimates, and timing.

- **Hastings WEC 1** – majority of capital is for a bottom ash recirculating system and blowdown reroute and a fly ash silo system.
- **PPGA WEC 2** – capital mainly consists of distributed control system (DCS) simulator and a DCS recontrol and excitation overhaul. Through the PPGA structure, MEAN serves as Managing Agent. MEAN also has representatives on PPGA's various committees and Board of Directors which gives MEAN a voice and a level of oversight related to capital projects and overall management and operation of WEC 2.
- **NPPD Ainsworth Wind** – contract ended September 30, 2025.

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	Current Budget	Projected	Proposed Budget	Preliminary 2027-2028	2028-2029	2029-2030	2030-2031	2031-2032
MEAN Capital	$ 136,000	$ 133,794	$ 180,000	$ 331,000	$ 175,000	$ 249,000	$ 167,000	$ 60,000
See *NMPP Energy - Capital Plan* report for detailed listing								
Owned Generation Capital (Productive Capacity)								
Wygen Unit I	1,980,665	2,139,175	1,347,470	1,797,723	2,705,025	1,911,034	1,248,276	1,940,313
LRS Units 1, 2, and 3	1,089,626	480,108	649,023	551,393	564,476	548,738	360,309	135,436
WSEC 4	2,971,676	3,456,930	1,069,034	833,316	2,902,889	3,830,073	434,515	464,058
Total Productive Capacity Assets	6,041,967	6,076,214	3,065,527	3,182,432	6,172,390	6,289,845	2,043,100	2,539,807
Total MEAN Capital and Owned Generation Capital	**6,177,967**	**6,210,008**	**3,245,527**	**3,513,432**	**6,347,390**	**6,538,845**	**2,210,100**	**2,599,807**
Contracted Generation Capital								
Hastings WEC 1	155,160	145,428	153,594	74,538	91,218	119,886	529,068	527,292
PPGA WEC 2	1,024,842	1,885,946	1,093,443	1,661,478	1,394,481	444,006	659,730	931,002
NPPD Ainsworth Wind	55,914	(2)						
Total Contracted Generation Capital	**1,235,916**	**2,031,372**	**1,247,037**	**1,736,016**	**1,485,699**	**563,892**	**1,188,798**	**1,458,294**
Total Capital Budget	**$ 7,413,883**	**$ 8,241,380**	**$ 4,492,564**	**$ 5,249,448**	**$ 7,833,089**	**$ 7,102,737**	**$ 3,398,898**	**$ 4,058,101**

All Capital Costs are in the FCRC.

NMPP Energy
Administrative and General Budget
Capital Plan
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	Last Purchased	Useful Life in Years	Current Budget 2025-2026	Projected Fiscal Year 2025-2026	Proposed Budget 2026-2027	Preliminary Budget 2027-2028	2028-2029	2029-2030	2030-2031	2031-2032
MEAN										
Wholesale Electric Operations and Utility Services										
Equipment										
Thermal/Infrared Camera (#1)	20-21	5	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,000	$ -
Field Site Analyzer (#1)	21-22	15	-	-	-	-	35,000	-	-	-
Field Site Analyzer (#2)	24-25	10	-	-	-	-	-	-	-	-
Power Quality Analyzer	25-26	5	-	14,661	-	-	-	-	-	-
Phase Tracker	N/A	5	10,000	Expensed	-	-	-	-	10,000	-
Executive										
Vehicles										
Electrical Distribution O&M (#1) - Large SUV	22-23	3	42,000	58,000	-	-	60,000	-	-	60,000
Electrical Distribution O&M (#2) - Truck/Mid Size SUV	24-25	3	-	-	30,000	-	-	40,000	-	-
Member Relations - Mid Size SUV	24-25	3	-	-	-	39,000	-	-	41,000	-
Generation Vehicle - Mid Size SUV	24-25	5	-	-	-	-	-	44,000	-	-
DSG/Telemetry Vehicle - Cargo Van	13-14	7	-	-	60,000	-	-	-	-	-
Building Renovation										
Conference Room - Top of Stairs #202	N/A	20	60,000	40,535	-	-	-	-	-	-
Building Equipment										
Heat Pump Replacements	12-13	15	-	-	75,000	77,000	80,000	100,000	35,000	-
Jace Controller for Heat Pump/Honeywell WESs Server	Sept 2018	5	-	-	15,000	-	-	-	-	-
Window Shades	12-13	10	-	-	-	-	-	26,000	-	-
Aqua Systems	12-13	15	-	-	-	-	-	10,000	-	-
Air Conditioning Unit for Server Room	12-13	15	-	-	-	37,000	-	-	-	-
Digital Solutions Group										
Board Room and Mobile Conference Equipment										
Projectors	19-20	10	-	-	-	-	-	29,000	-	-
Sound System	20-21	10	-	-	-	-	-	-	21,000	-
Cameras and Video Display	20-21	10	-	-	-	-	-	-	20,000	-
IT Infrastructure										
Building Camera System	12-13	10	-	-	-	20,000	-	-	-	-
Backup and Recovery Appliances	20-21	5	-	-	-	15,000	-	-	-	-
Switches-Corporate Network and MEAN SCADA	17-18 through 20-21	5	-	-	-	60,000	-	-	-	-
Firewall Update-Corporate Network and MEAN SCADA	20-21	5	24,000	20,598	-	-	-	-	25,000	-
SAN (Storage Area Network Server) Refresh	22-23	5	-	-	-	40,000	-	-	-	-
VM Hosts Refresh	22-23	5	-	-	-	43,000	-	-	-	-
Total MEAN			**$ 136,000**	**$ 133,794**	**$ 180,000**	**$ 331,000**	**$ 175,000**	**$ 249,000**	**$ 167,000**	**$ 60,000**

NOTE: Only the estimated costs for each project are noted. Additional related operating expenses may also be incurred and will be included in the A&G budget
Staff continues to research various systems and components of the building as we've passed 10 years since construction.
Report may include items approved for purchase in the current and prior years. Various factors impact the actual time period in which the purchase is made.

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Debt Service Narrative
Fiscal Year 2026-2027

	Current Budget	Projected	Proposed Budget	Preliminary 2027-2028	2028-2029	2029-2030	2030-2031	2031-2032
MEAN Debt Service								
2013A Principal	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2013A Interest	979,438	979,438	979,438	979,438	979,438	979,438	979,438	979,438
Total 2013A	979,438	979,438	979,438	979,438	979,438	979,438	979,438	979,438
2016A Principal	1,885,000	1,885,000	1,985,000	2,085,000	2,185,000	2,310,000	2,415,000	2,535,000
2016A Interest	2,370,150	2,370,150	2,275,900	2,176,650	2,072,400	1,963,150	1,847,650	1,726,900
Total 2016A	4,255,150	4,255,150	4,260,900	4,261,650	4,257,400	4,273,150	4,262,650	4,261,900
2022A Principal	2,980,000	2,980,000	3,130,000	3,285,000	3,450,000	3,605,000	3,800,000	3,990,000
2022A Interest	1,212,000	1,212,000	1,063,000	906,500	742,250	569,750	389,500	199,500
Total 2022A	4,192,000	4,192,000	4,193,000	4,191,500	4,192,250	4,174,750	4,189,500	4,189,500
Total MEAN Principal	4,865,000	4,865,000	5,115,000	5,370,000	5,635,000	5,915,000	6,215,000	6,525,000
Total MEAN Interest	4,561,588	4,561,588	4,318,338	4,062,588	3,794,088	3,512,338	3,216,588	2,905,838
Total MEAN Debt Service	9,426,588	9,426,588	9,433,338	9,432,588	9,429,088	9,427,338	9,431,588	9,430,838
Investment Return - Debt Related Funds	(364,750)	(477,912)	(385,375)	(366,375)	(359,375)	(352,375)	(345,375)	(338,375)
Total MEAN Debt Service, Net	**9,061,838**	**8,948,676**	**9,047,963**	**9,066,213**	**9,069,713**	**9,074,963**	**9,086,213**	**9,092,463**
Contracted Generation Debt Service								
PPGA WEC 2, Net of Debt Related Investment Return	13,235,568	13,694,722	13,935,870	14,486,179	14,397,843	14,273,412	14,269,992	14,516,466
WSEC4 Waverly Assignment	333,570	333,569	338,418	342,441	352,239	365,412	368,130	374,421
Louisa Waverly Assignment	865,584	865,586	878,166	888,621	879,051	808,125	807,636	795,540
NPPD Ainsworth Wind	426,750	426,750						
Total Contracted Generation Debt Service, Net	**14,861,472**	**15,320,627**	**15,152,454**	**15,717,241**	**15,629,133**	**15,446,949**	**15,445,758**	**15,686,427**
Total Debt Service, Net	**$ 23,923,310**	**$ 24,269,303**	**$ 24,200,417**	**$ 24,783,454**	**$ 24,698,846**	**$ 24,521,912**	**$ 24,531,971**	**$ 24,778,890**

All debt service costs are included in the FCRC.

Debt Service Narrative

MEAN Debt Service, Net – the schedule reflects the required principal and interest payments for MEAN's outstanding debt issues. Estimates of investment return are based on current interest rates, annual debt fund requirements, and current expectations of future rates.

Contracted Generation Debt Service, Net – these costs are reported within Purchased Power Expenses – Contracted Purchases; therefore, variances have an impact on MEAN's net revenue. As MEAN does not own the related contracted generation, the debt service costs are recorded as expenses in the year incurred. The NPPD Ainsworth Wind contract ended on September 30, 2025. See *the Purchased Power Expenses Narrative* section for discussion by resource.

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Budget, Rates, and Charges
Administrative and General Expenses Narrative
Fiscal Year 2026-2027

Administrative and General Budget Process

The administrative and general (A&G) budget is prepared annually based on strategic focus areas identified by the management team of NMPP Energy. In September, accounting staff compiles historical data and populates budget templates based on information available. The management team holds a strategic planning session to review short-term and long-term plans across the four companies of NMPP Energy. Department directors then prepare budgets during September and October based on anticipated projects and needs resulting from the strategic focus areas discussed. The strategic focus areas identified continue to stem from the technical complexity of the industry including the evolving energy markets.

Nebraska Municipal Power Pool (NMPP), Municipal Energy Agency of Nebraska (MEAN), National Public Gas Agency (NPGA) and Public Alliance for Community Energy (ACE) have entered into an agreement establishing a Joint Operating Committee (JOC) due in part to the companies sharing common staff all of which reside under NMPP. By combining and sharing staff and resources each company benefits by being able to perform obligations and responsibilities efficiently and at a lesser cost.

Duties of the JOC as detailed in the Joint Operating Committee Agreement include the following:

- Review, prior to the respective annual meetings, the annual payroll and benefits and other shared administrative costs budgeted for each of the Parties (NMPP, MEAN, NPGA and/or ACE).
- Determine the allocation of payroll and benefits and other shared administrative and general costs to be used as the basis for reimbursement for services rendered or resources utilized by a Party.
- Approve the appropriate compensation structure and benefits of employees of NMPP.

MEAN's Finance Committee meets in October to review the preliminary shared A&G for the Proposed Budget that will be presented to the JOC. The JOC meets in November and receives a detailed proposed A&G budget packet. The packet, along with additional discussion and presentation at the meeting, assists the JOC in fulfilling the duties noted.

Administrative and General Expenses

For ease of analysis, MEAN breaks A&G expenses into the following four categories: payroll and benefits, internal office, member, and consultants and outside services.

Payroll and Benefits

Payroll and benefits consist of gross wages, employer payroll taxes and costs of benefits provided by NMPP to each employee. As noted, one of the duties of the JOC is to approve the appropriate compensation structure and benefits of employees of NMPP. The annual review and approval for any changes in compensation structure and benefits is part of the November JOC meeting. There is no change in compensation structure or benefits offered in the Proposed Budget.

The budgeted increase related to anticipated performance/merit pay adjustments is 4.64% in the Proposed Budget (Current Budget was 5.10%). The Proposed Budget also reflects the final benefit renewals for calendar 2026 and estimates for calendar 2027.

Budgeted Positions

As part of the budget process, management of the NMPP Energy companies discussed whether changes in the operations of each of the underlying companies resulted in changes in roles or responsibilities of current positions or resulted in a need for additional personnel. No additional personnel were identified for NPGA or ACE.

The budget assumes all positions will be filled each day of the fiscal year unless otherwise noted. This assumption is the primary reason for significant actual vs. budget variances as the actual timing of when budgeted positions are filled do not always match the budgeted timing.

Total budgeted full-time equivalent positions for all NMPP Energy companies are 53.0 in the Proposed Budget compared to 53.0 in the Current Budget and 50.0 in the Fiscal Year 2024-2025 budget.

Cost Allocations

Under the methodology approved by the JOC, payroll and benefits expenses are allocated to NPGA, ACE, and NMPP based on the estimated market payroll and benefits expenses each Party would incur if each company employed their own independent staff. Annual payroll and benefits costs for NPGA, ACE, and NMPP are established during the JOC budget process based on the hypothetical estimates of payroll and benefits expenses. The total budgeted payroll and

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benefits costs net of the established amounts for NPGA, ACE, and NMPP are allocated to MEAN. The allocation of payroll and benefits expenses is reviewed and recommended by the JOC annually.

Under the allocation methodology approved by the JOC, the payroll and benefits paid by NGPA, ACE, and NMPP are fixed annually unless a business change occurs during the year requiring a change in personnel or a change occurs to the underlying compensation and benefit assumptions. As a result, MEAN bears the risk and reward related to over or under spending in payroll and benefits, unless the variance is related to a business change for NPGA, ACE, or NMPP.

The following table summarizes the budgeted payroll and benefits cost by company, as approved at the November 2025 JOC meeting.

Payroll and Benefits								
	Proposed Budget			Current Budget			vs. Current	
		Amount	% of Total		Amount	% of Total	$ +/-	% +/-
MEAN	**$**	**8,858,462**	**90%**	**$**	**8,765,196**	**90%**	**$ 93,266**	**1%**
NPGA		**485,400**	**5%**		**465,600**	**5%**	**19,800**	**4%**
ACE		**460,600**	**5%**		**441,900**	**5%**	**18,700**	**4%**
Total	**$**	**9,804,462**	**100%**	**$**	**9,672,696**	**100%**	**$ 131,766**	**1%**

Other A&G Expenses - Direct
Other A&G expenses consist of direct costs and shared costs. NMPP Energy attempts to assign costs whenever possible to the specific company with which the cost is associated. Direct costs include the A&G expenses that are specific to the business operating needs of each individual company. The costs incurred are generally attributable to invoices and/or contracts with vendors relating to a cost incurred by the specific company.

The following provides highlights of the budgeted changes in direct costs for MEAN. See the *NMPP Energy – Detail by Company – MEAN* report.

MEAN Direct Other A&G				
	Proposed Budget	**Current Budget**	**Proposed vs. Current $ +/-**	**% +/-**
Internal Office	$ 1,056,675	$1,040,321	$ 16,354	2%
Member	366,663	364,238	2,425	1%
Consultant & Outside Services	5,672,983	5,716,446	(43,463)	-1%
Total MEAN Direct Other A&G	**$ 7,096,321**	**$7,121,005**	**$ (24,684)**	**0%**

Internal Office

- **Conferences and training** – registration fees for industry and job specific conferences and training; budget is prepared based on training plans for staff. There was a minimal increase in costs between years.
- **Dues and subscriptions** – consist of costs for belonging to various professional, trade, working groups, required regulatory organizations, and subscriptions for various services. While assessments continue to increase, the budgeted decrease is due to expected elimination of costs as a result of the market expansion.
- **Equipment lease and maintenance** – technology related costs are cyclical resulting in larger swings year to year.
- **Glynoaks operations** – consists of operating costs of the Glynoaks building including repairs and maintenance, cleaning, utilities, professional services, and common area maintenance. These costs are paid by MEAN and recovered in part through rent charged to the other companies. Increase is due to a general increase in costs.
- **Insurance** – insurance packages are purchased to manage the risks of the organizations. Increase is due to anticipated increases in premiums during next cycle of renewals.
- **Miscellaneous** – costs that do not fall within one of the identified categories are reported as miscellaneous. There is no change based on review of historical actuals.
- **Telecommunications** – costs include broadband services, cell reimbursements, ICCP site service and general office telecommunication costs. Increase is based on review of recent actuals.

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- **Travel, lodging and meals –** this category includes both staff travel to attend various conferences and industry meetings as well as travel related to MEAN's operations. Decrease is based on planned activity and review of recent actuals.

Member

- **Advertising – corporate image** – costs include promotional items for MEAN and sponsorships of various trade association events. There was a minimal increase in costs between years.
- **Board and committee meetings** – costs to hold the various meetings throughout the year. MEAN budgets for all planned Board meetings to be held in person. Decrease is based on review of recent actuals.
- **Member dues – MEAN** – consistent with prior year, the Proposed Budget includes the American Public Power Association (APPA) Member Dues and Demonstration of Energy and Efficiency Developments (DEED) program dues paid by MEAN on behalf of MEAN Participants; slight increase relates to expected costs from APPA.
- **Member education** – Proposed Budget includes costs to hold the Generation Conference and costs related to training services. These costs are offset in part by related registration fees, sponsorships and contracts for service.
- **Member scholarships** – includes the estimated costs for scholarships to assist MEAN Participants with training. Budgeted costs are based on review of actuals and expectations of utilization.
- **Rebates paid – MEAN** – costs for retail rebate and commercial LED lighting programs. Actual costs vary depending on the level of utilization by MEAN Participants. Budgeted costs are based on review of actuals and expectations of utilization.

Consultants and Outside Services

- **Audit and consulting** – these costs relate to the costs for the annual financial statement audit, as determined by the auditors, and occasional accounting consultation. Cost increases annually.
- **Financing – MEAN** – these costs result from MEAN's line of credit and costs associated with outstanding bonds such as trustee fees, periodic bond arbitrage calculations, financial advisor services, and rating agency annual monitoring fees. The decrease is due to the cyclical nature of arbitrage calculations.
- **Legal** – represents budgeted legal projects requiring outside counsel. Costs related to litigation, disputes, or arbitration are budgeted only with regards to ongoing disputes at the time the budget is prepared; no such costs are included in the Proposed or Current Budget. The budgeted costs relate primarily to outside FERC counsel, RTO related matters, and bond counsel. The decrease is based on a review of recent actuals and planned projects.
- **Market management** – relates to consulting costs with outside vendors. The services provided result in value through implementation of various generation, transmission, and market strategies. The Proposed Budget includes cyclical costs related to integrated resource plan analysis and an estimate of market implementation costs related to changing market activity that is expected to occur over the next two fiscal years. The cyclical costs in the Proposed Budget are less than the Current Budget resulting in a total increase that is less than the annual increase on the base agreement. The market development impact is still being evaluated and may change for the January meeting.
- **Other consultants and outside services** – include various consultant and outside service projects that don't fall within other identified categories. These projects are often cyclical resulting in fluctuating costs annually. The Current Budget included one-time costs related to the expansion of market activity in the west. The Proposed Budget includes estimates of costs related to expansion of market activity in the West. Planned activity during the Current Budget experienced delays from third parties resulting in one-time costs being included in both budget years. The timing and scope of many of these costs are still being evaluated. Further analysis and information received resulted in an increase in costs compared to December.
- **Software, licenses, maintenance, and support** – costs relate to software technology utilized by MEAN and generally increase annually. A large portion of the increase in costs reported as A&G expenses relates primarily to increased market platform software costs because of expanded market activity. In the December meeting materials, expected costs for tools related to integrated resource plan (IRP) analysis were included in other consultants and outside services. After additional analysis, it was determined a software platform would best meet the needs of these activities. The software will also be utilized for resource planning and other projects. Due to accounting standards, MEAN also records approximately $476,000 of software costs as amortization expense.

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Other A&G Expenses - Shared

Shared costs consist of costs for products and services that are shared by all of the companies. Although each company may benefit from the shared products and services, if each Party operated independently, each product and service may be required at a higher or lower level than the amount purchased collectively. MEAN's Finance Committee meets in October to review the preliminary shared A&G for the Proposed Budget that is presented to the JOC in November. Shared costs are considered annually by the JOC when establishing rent paid to MEAN.

The following provides highlights of the budgeted changes in shared other A&G costs for MEAN. See the *NMPP Energy – Detail by Company – MEAN* report.

MEAN Shared Other A&G				
	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-
Internal Office	$ 434,259	$ 458,500	$ (24,241)	-5%
Member	31,214	24,177	7,037	29%
Consultant & Outside Services	365,629	319,117	46,512	15%
Total MEAN Shared Other A&G	**$ 831,102**	**$ 801,794**	**$ 29,308**	**4%**

The following includes a description of the primary drivers of the variances between years:

- **Internal Office** – cyclical projects in the Current Budget including a conference room build out and firewall replacement were completed and replaced in the Proposed Budget by the proposed purchase of mobile conference equipment to provide better audio for offsite meetings and events. The overall decrease relates to lower current premiums compared to what had been expected during last year's budget process for joint insurance costs.
- **Member** – increase is due to an increase in costs for collective advertising, JOC meetings, and costs paid to NMPP.
  - **Services from/(to) NMPP** – NMPP costs not covered by NMPP revenues are allocated to MEAN, NPGA and ACE based on each company's share of total budgeted payroll and benefits. Variances from budget will result in an annual true-up each fiscal year end. Costs consist of holding the NMPP Energy annual conference, the annual audit and tax consulting, lobbying contract with a Nebraska lobbyist, and other miscellaneous items. These costs are offset in part by annual conference revenues equal to budgeted conference expenses and champion dues. NMPP's budget was approved by the NMPP Board. The budget was also reviewed by the JOC and the JOC determined the allocation. The following table provides a summary of the budgeted services reimbursement.

Services Reimbursement					
	% of Total Payroll	Proposed Budget	Current Budget	Proposed vs. Current $ +/-	% +/-
MEAN	**90%**	**$ 25,789**	**$ 19,327**	**$ 6,462**	**33%**
NPGA	**5%**	**1,433**	**1,074**	**359**	**33%**
ACE	**5%**	**1,433**	**1,074**	**359**	**33%**
Total Services Reimbursement to NMPP		**$ 28,655**	**$ 21,475**	**$ 7,180**	**33%**

- **Consultants and Outside Services** – increase in other consulting costs due to cyclical costs for project assistance. Most of the increase is due to higher software licensing fees and a data warehouse project impacting all organizations.

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	MEAN															
							Proposed vs. Current							Proposed vs.		Actuals Fiscal Year
	Proposed Budget			Current Budget			$ +/-			% +/-			Projected	Projected		2024-2025
	Direct	Shared	Total	Direct	Shared	Total	Direct	Shared	Total	Direct	Shared	Total	Total	$ +/-	% +/-	Total
Payroll and Benefits	$ -	$ 8,858,462	$ 8,858,462	$ -	$ 8,765,196	$ 8,765,196	$ -	$ 93,266	$ 93,266	-	1%	1%	$ 7,723,853	$ 1,134,609	15%	$ 6,871,434
Internal Office																
Conferences and training	61,800	24,775	86,575	59,630	23,175	82,805	2,170	1,600	3,770	4%	7%	5%	67,742	18,833	28%	33,612
Dues and subscriptions	227,160	13,473	240,633	257,095	16,568	273,663	(29,935)	(3,095)	(33,030)	-12%	-19%	-12%	268,861	(28,228)	-10%	255,150
Equipment lease and maintenance	114,102	102,933	217,035	95,544	109,570	205,114	18,558	(6,637)	11,921	19%	-6%	6%	214,497	2,538	1%	180,225
Glynoaks operations	174,691	-	174,691	166,559	-	166,559	8,132	-	8,132	5%	-	5%	162,416	12,275	8%	138,045
Insurance	120,488	170,651	291,139	96,350	196,175	292,525	24,138	(25,524)	(1,386)	25%	-13%	0%	289,506	1,633	1%	270,027
Miscellaneous	500	20,500	21,000	500	18,750	19,250	-	1,750	1,750	0%	9%	9%	15,787	5,213	33%	15,845
Office supplies	-	10,000	10,000	-	11,300	11,300	-	(1,300)	(1,300)	-	-12%	-12%	8,576	1,424	17%	8,861
Postage	-	6,000	6,000	-	7,000	7,000	-	(1,000)	(1,000)	-	-14%	-14%	4,460	1,540	35%	3,686
Telecommunications	90,310	63,320	153,630	69,774	54,560	124,334	20,536	8,760	29,296	29%	16%	24%	132,818	20,812	16%	147,681
Travel, lodging and meals	267,624	22,607	290,231	294,869	21,402	316,271	(27,245)	1,205	(26,040)	-9%	6%	-8%	268,982	21,249	8%	186,216
Total internal office	1,056,675	434,259	1,490,934	1,040,321	458,500	1,498,821	16,354	(24,241)	(7,887)	2%	-5%	-1%	1,433,645	57,289	4%	1,239,347
Member																
Advertising - corporate image	12,913	3,950	16,863	12,188	3,450	15,638	725	500	1,225	6%	14%	8%	15,654	1,209	8%	9,947
Annual conference	-	-	-	-	-	-	-	-	-	-	-	0%	-	-	-	1,146
Board and committee meetings	62,800	1,475	64,275	70,350	1,400	71,750	(7,550)	75	(7,475)	-11%	5%	-10%	70,072	(5,797)	-8%	58,449
Member dues - MEAN	170,400	-	170,400	162,900	-	162,900	7,500	-	7,500	5%	-	5%	166,888	3,512	2%	161,452
Member education	35,550	-	35,550	33,800	-	33,800	1,750	-	1,750	5%	-	5%	36,096	(546)	-2%	28,194
Member scholarships	10,000	-	10,000	10,000	-	10,000	-	-	-	0%	-	0%	11,531	(1,531)	-13%	7,128
Rebates paid - MEAN	75,000	-	75,000	75,000	-	75,000	-	-	-	0%	-	0%	66,649	8,351	13%	70,947
Services from / (to) NMPP	-	25,789	25,789	-	19,327	19,327	-	6,462	6,462	-	33%	33%	19,327	6,462	33%	-
Total member	366,663	31,214	397,877	364,238	24,177	388,415	2,425	7,037	9,462	1%	29%	2%	386,217	11,660	3%	337,264
Consultants and Outside Services																
Audit and consulting	46,550	-	46,550	45,200	-	45,200	1,350	-	1,350	3%	-	3%	45,200	1,350	3%	45,150
Financing - MEAN	83,200	-	83,200	85,200	-	85,200	(2,000)	-	(2,000)	-2%	-	-2%	85,600	(2,400)	-3%	86,150
Legal	70,000	2,600	72,600	75,000	2,600	77,600	(5,000)	-	(5,000)	-7%	0%	-6%	68,701	3,899	6%	64,944
Market management	2,441,972	-	2,441,972	2,423,276	-	2,423,276	18,696	-	18,696	1%	-	1%	2,519,489	(77,517)	-3%	2,903,517
Other	2,659,840	105,475	2,765,315	2,803,145	95,675	2,898,820	(143,305)	9,800	(133,505)	-5%	10%	-5%	370,692	2,394,623	646%	377,031
Software licenses, maint., support	371,421	257,554	628,975	284,625	220,842	505,467	86,796	36,712	123,508	30%	17%	24%	459,466	169,509	37%	207,538
Total consultants and outside services	5,672,983	365,629	6,038,612	5,716,446	319,117	6,035,563	(43,463)	46,512	3,049	-1%	15%	0%	3,549,148	2,489,464	70%	3,684,331
Total other administrative and general	7,096,321	831,102	7,927,423	7,121,005	801,794	7,922,799	(24,684)	29,308	4,624	0%	4%	0%	5,369,010	2,558,413	48%	5,260,942
Total Administrative and General Expenses	**$ 7,096,321**	**$ 9,689,564**	**$ 16,785,885**	**$ 7,121,005**	**$ 9,566,990**	**$ 16,687,995**	**$ (24,684)**	**$ 122,574**	**$ 97,890**	**0%**	**1%**	**1%**	**$ 13,092,863**	**$ 3,693,022**	**28%**	**$ 12,132,376**
Total Software, Licenses, Maint., Support Costs																
A&G - expenses	$ 371,421	$ 257,554	$ 628,975	$ 284,625	$ 220,842	$ 505,467	$ 86,796	$ 36,712	$ 123,508	30%	17%	24%	$ 459,466	$ 169,509	37%	$ 207,538
Subscription liability payments	478,516	25,212	503,728	354,515	75,376	429,891	124,001	(50,164)	73,837	35%	-67%	17%	$ 429,891	73,837	17%	$ 422,780
Total software, licenses, maint., support costs	$ 849,937	$ 282,766	$ 1,132,703	$ 639,140	$ 296,218	$ 935,358	$ 210,797	$ (13,452)	$ 197,345	33%	-5%	21%	$ 889,357	$ 243,346	27%	$ 630,318

Municipal Energy Agency of Nebraska
Budget, Rates, and Charges
Statements of Revenues, Expenses and Changes in Net Position
Years Ending March 31

	2024	2025	Projected 2026*	Budget 2027
Operating Revenues				
Electric energy sales				
Long-term total requirements	$ 104,725,081	$ 112,272,498	$ 125,123,108	$ 133,553,177
Limited-term total requirements	11,843,586	12,022,777	12,509,516	12,626,639
Interchange sales	7,778,776	10,322,838	5,482,080	360,000
Total electric energy sales	124,347,443	134,618,113	143,114,704	146,539,816
Transfer from / (provision for) rate stabilization	1,000,000	(1,500,000)	-	-
Other	2,068,349	2,287,381	3,327,775	2,477,414
Total operating revenues	127,415,792	135,405,494	146,442,479	149,017,230
Operating Expenses				
Electric energy costs				
Purchased power	81,080,806	82,499,406	91,114,437	86,663,936
Production	17,516,577	16,466,707	17,802,974	18,164,984
Transmission	6,004,123	7,519,300	7,900,494	8,379,707
Total electric energy costs	104,601,506	106,485,413	116,817,905	113,208,627
Administrative and general	11,026,431	12,132,374	13,092,863	16,785,885
Depreciation and amortization	8,832,561	9,089,133	9,624,978	9,972,185
Total operating expenses	124,460,498	127,706,920	139,535,746	139,966,697
Operating Income / (Loss)	2,955,294	7,698,574	6,906,733	9,050,533
Nonoperating Revenues (Expenses)				
Net costs to be recovered in future periods	(1,076,251)	(1,292,170)	(55,337)	(342,831)
Investment return	3,182,110	3,105,629	2,654,963	2,114,375
Interest expense	(4,743,211)	(4,450,441)	(4,139,107)	(3,882,016)
Net nonoperating expenses	(2,637,352)	(2,636,982)	(1,539,481)	(2,110,472)
Change in Net Position	317,942	5,061,592	5,367,252	6,940,061
Net Position, Beginning of Year	59,922,595	60,240,537	65,302,129	70,669,381
Net Position, End of Year	$ 60,240,537	$ 65,302,129	$ 70,669,381	$ 77,609,442

*Consistent with MEAN's Financial and Administrative Policies and Guidelines, MEAN will evaluate its preliminary Fiscal Year change in net position upon closing of MEAN's annual financial records including all year end accruals and Fiscal Year transactions. After evaluation of preliminary results, MEAN may transfer a portion of its preliminary Fiscal Year change in net position into the rate stabilization account or from the rate stabilization account. MEAN may also consider various adjustments which may result in changes in electric energy sales.