Schedule CB-4

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Memorandum

Date: February 5, 2025

To: Brad Lutz, Evergy

From: Craig Brown & Ryan Collins, 1898 & Co.

Subject: Large Customer Analysis

Project Background

1898 & Co., part of Burns & McDonnell, has been retained by Evergy, Inc. (Evergy) to analyze the impact on cost of service allocations and rate revenue in the event of adding a very large new customer (Customer) to the system. The analysis is based on the Missouri Metro jurisdiction, and the customer is assumed to be part of the Large Power Service (LPS) rate class. 1898 & Co. used the most recent Missouri Metro Class Cost of Service (CCOS) model for the analysis. Detailed calculations and assumptions are shown in the CCOS model and supporting workpapers. This memo outlines the assumptions and summarizes the results.

Compilation of Data and Assumptions

1898 & Co. submitted a data request to Evergy to gather the required information, which is grouped into the following:

- New Customer Information
- New Infrastructure Required
- Changes to Operating Expenses
- Changes to Current Rates

New Customer Information

Based on discussions with Evergy, the following assumptions were made for the Customer:

- Takes service at transmission voltage (69 kV or higher)
- 384 megawatts (MW) non-coincident peak (NCP) demand
- 90% coincidence factor with system peak
- 85% monthly load factor
- An additional $9.59 per kW-month from a new System Support Rider to offset incremental power supply costs.

With an 85% load factor, the Customer will add approximately 2.9 million megawatt hours (MWh) per year to the LPS class. These assumptions and Evergy's current rate tariff for the Missouri Metro jurisdiction were used to calculate the Customer's base rate revenue projections. The CCOS model includes a detailed revenue calculation summarized in Table 1.

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Table 1: Annual Base Rate Revenue

Base Rate Revenue Summary	
Customer Charge	$14,175
Demand Charge	$27,622,705
Energy Charge	$135,236,390
Total Base Revenue	**$162,873,271**

The customer charge is based on one meter, assuming that metering will be totalized/aggregated if needed. Demand charges are modeled assuming the full load of 384 MW each month. Energy charges are modeled based on the 85% load factor assumption and the corresponding hours in each month of the year. The Fuel Adjustment Clause (FAC) and Demand Side Investment Mechanism Rider (DSIM) have been excluded from the calculation as they are excluded from class revenues in the CCOS model.

Evaluated Scenarios

Based on additional discussions with Evergy, 1898 & Co. evaluated two separate cost scenarios related to the potential addition of the Customer.

Scenario 1 - No New Generation: This scenario assumes that Evergy does not build any new generation assets specific to this load and instead bases additional costs on assumed increases in capacity costs and incremental energy costs associated with serving the Customer.

Scenario 2 - New Combined Cycle Power Plant: Assumes that Evergy will be building a new combined cycle gas turbine (CCGT) to help service this load. In this scenario, a 400 MW share of a newly built CCGT is added to Evergy's rate base along with assumed depreciation expense, operation & maintenance expense, property insurance, and property taxes.

Scenario 1 – No New Generation

Under Scenario 1, it was assumed that no new generation assets will be built and any new infrastructure required to serve the Customer will be paid for by the Customer. This includes any transmission line upgrades, substation additions, and distribution additions to the Evergy system within the Missouri Metro jurisdiction. Based on these assumptions, infrastructure additions and other correlated costs specifically to serve the Customer have been excluded from the analysis as there would be no net increase to Evergy's MO Metro rate base.

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Changes to Operating Expenses

Operating expenses have been adjusted based on assumed changes in power supply and operating capacity costs. These changes have been reflected in FERC account 555.00 – Purchased Power Expense. To account for increased capacity costs, $11.00 per kilowatt (kW) per month was added to FERC account 555.00 – Purchased Power Energy and Capacity. The Evergy team provided this $11.00/kW-month assumption for the analysis. For purchased energy, $25.00/MWh was also added to FERC account 555.00. This value is based on a separate study evaluating the incremental impact of adding large loads within Evergy's jurisdiction.

Additionally, a system support charge of $9.59 per kW was assessed, generating $44,190,720 in additional revenues. This charge is intended to offset the unforeseen power supply and capacity cost impact on other classes caused by serving the new customer, as discussed with Evergy. Table 2 summarizes the assumed changes in operating expenses.

Table 2: Scenario 1 Additional Operating Expense Summary

Revenue Requirement Summary	
555.00 Purchased Power - Capacity	
Original TY Value	$253,973,697
Large Customer Additional Expense	
$11.00/kW-month	$50,688,000
Total 555 - Purchased Power Capacity	**$304,661,697**
555.00 Purchased Power Expense - Incremental Energy	
Original TY Value	$253,973,697
Large Customer Additional Expense	
$0.025/kWh	$71,481,600
Total 555 - Purchased Power Energy	**$325,455,297**
447.01 System Support Rider	
Large Customer Additional Expense	
System Support Rider	**($44,190,720)**
Total Revenue Requirements Added	**$77,978,880**

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Class Cost of Service Modeling

After determining the additional revenue and operating expense, 1898 & Co. input these values into the existing CCOS model. Where appropriate, we updated the allocation factors to account for the potential addition of the Customer's load profile. This included updating demand, energy, and customer allocators for the LPS rate class. The impact on the LPS rate class of adding the Customer under the established assumptions and updated allocation factors is shown in Table 3.

Table 3: Scenario 1 LPS Class Cost of Service Comparison

Large Power Service	TY Original Values	Including LPS Test Customer	Change
Revenue	$121,482,208	$284,355,479	$162,873,271
Net Revenue Requirement	$87,551,889	$208,797,391	$121,245,502
Net Operating Income	**$33,930,320**	**$75,558,088**	**$41,627,768**
Rate Base	$ 352,376,054	$ 738,736,460	$ 386,360,406
Rate of Return at Present Rates	9.63%	10.23%	0.60%

As shown in Table 3, adding the Customer increases the LPS class's net operating income by approximately $42 million. The return on rate base at present rates increases from 9.63% to 10.23%, indicating that the LPS class benefits from the addition of the Customer under this set of assumptions and inputs. Notably, the addition of the Customer will cause the class to continue over-recovering its return from a class cost-of-service perspective.

Table 4 provides a rate of return under present rates comparison for each rate class and the entire Missouri Metro system. As a note, this comparison is with current 2024 rates and a 2021 test year revenue requirement. As shown, each rate class except for the CCN class benefits from adding the Customer. The 2.69% overall system increase in the rate of return indicates that the Customer's potential addition to the system would be a net benefit for Evergy and its current ratepayers under Scenario 1.

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Table 4: Scenario 1 Class Rates of Return

Class	Rate of Returns at Present Rates		
	TY Original Values	Including LPS Test Customer	Change
Residential	2.04%	4.03%	1.99%
Small General Service	9.08%	12.19%	3.11%
Medium General Service	10.11%	14.09%	3.98%
Large General Service	10.33%	14.34%	4.01%
Large Power Service	9.63%	10.23%	0.60%
Lighting	9.62%	11.45%	1.83%
CCN	-55.49%	-56.25%	-0.77%
MO Metro Retail	**5.88%**	**8.57%**	**2.69%**

A unit cost comparison is shown in Table 5. On a per-unit basis, customer costs increase by $7.19, energy costs increase slightly, and demand costs decrease by $1.92. The demand decrease for the LPS class is a result of adding the Customer's additional 2.9 million MWh energy sales.

Table 5: Scenario 1 Unit Costs at Present Rates

Unit Costs at Present Rates			
Large Power Service Unit Costs	TY Original Values	Including LPS Test Customer	Change
Customer Costs	$118.95	$126.14	$7.19
Excluding Local Facilities	$108.63	$115.14	$6.50
Average Cost per kWh	$0.02708	$0.02988	$0.00280
Demand Cost Per Billing kW	$21.26	$19.34	($1.92)
Production Demand	$14.62	$13.37	($1.25)
Transmission Demand	$2.45	$2.19	($0.26)
Distribution Demand	$4.19	$3.78	($0.42)

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Scenario 2 – New CCGT Plant

Under Scenario 2, it was assumed that Evergy will build a new combined cycle gas turbine plant and add a 400 MW share to its jurisdictional rate base to serve the Customer. Similar to Scenario 1, any subsequent new infrastructure required to serve the Customer will be paid for by the Customer up front. This includes any transmission line upgrades, substation additions, and distribution additions to the Evergy system within the Missouri Metro jurisdiction.

Changes to Operating Expenses

To account for the new plant in rate base, 1898 & Co. added $629 million to FERC account 344. The $629 million is based on an estimated 400 MW share of a CCGT. Multiple adjustments to operating expenses have been made based on the addition of the CCGT. These include changes to depreciation expense, fixed operation and maintenance (O&M) expense, variable O&M expense, property insurance expense, and property tax expense. Expense estimates were based on our experience and discussed with Evergy.

Additionally, a system support charge of $9.59 per kW-month was assessed, generating an additional $44,190,720 in other revenues. This charge offsets unforeseen power supply cost and capacity cost impacts on other classes due to serving the new customer. Table 6 summarizes the assumed changes in rate base and the corresponding operating expenses.

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Table 6: Scenario 2 Additional Operating Expense Summary

Revenue Requirement Summary	
Rate Base Additions	
344 Generators PROD OTHER - MIAMI/OSAWATOMIE 1	
Original TY Value	$13,596,141
Large Customer Additional Expense	
400 MW Share of CC Plant	$628,571,429
Total 344 - Generators	**$642,167,569**
Revenue Requirement Additions	
Depreciation Expense - Production	
Original TY Value	$108,615,296
Large Customer Additional Expense	
Annual Depreciation Expense	$20,952,381
Total Depreciation Expense - Production	**$129,567,677**
549 Misc Other Power Generation Expense	
Original TY Value	$581,745
Large Customer Additional Expense	
Fixed O&M	$4,800,000
Total 549 Misc Other Power Generation Expense	**$5,381,745**
552 Other General Maintenance of Structures	
Original TY Value	$66,570
Large Customer Additional Expense	
Variable O&M	$14,343,807
Total 552 Other General Maintenance of Structur	**$14,410,378**
924 Property Insurance	
Original TY Value	$1,200,322
Large Customer Additional Expense	
Property Insurance	$3,142,857
Total 924 Property Insurance	**$4,343,179**
408.1 Property Tax	
Original TY Value	$68,253,459
Large Customer Additional Expense	
Property Tax	$4,761,905
Total 408.1 Property Tax	**$73,015,364**
555.00 Purchased Power Expense - Incremental Energy	
549 Misc Other Power Generation Expense	$253,973,697
Large Customer Additional Expense	
$0.025/kWh	$71,481,600
Total 555 - Purchased Power Energy	**$325,455,297**
447.01 System Support Rider	
Large Customer Additional Expense	
System Support Rider	**($44,190,720)**
Total Revenue Requirements Added	**$75,291,830**

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Class Cost of Service Modeling

After determining the additional revenue and operating expense, 1898 & Co. input these values into the existing CCOS model. Where appropriate, 1898 & Co. updated the allocation factors to account for the potential addition of the Customer's load profile. This included updating demand, energy, and customer allocators for the LPS rate class. The impact on the LPS rate class of adding the Customer under the established assumptions and updated allocation factors is shown in Table 7.

Table 7: Scenario 2 LPS Class Cost of Service Comparison

Large Power Service	TY Original Values	Including LPS Test Customer	Change
Revenue	$121,482,208	$284,355,479	$162,873,271
Net Revenue Requirement	$87,551,889	$208,212,956	$120,661,068
Net Operating Income	**$33,930,320**	**$76,142,522**	**$42,212,203**
Rate Base	$ 352,376,054	$ 897,404,880	$ 545,028,826
Rate of Return at Present Rates	9.63%	8.48%	-1.14%

As shown in Table 7, adding the Customer increases the LPS class's net operating income by approximately $42 million. The return on rate base at present rates decreases from 9.63% to 8.48%, indicating that the LPS class is slightly harmed by adding the Customer under this set of assumptions and inputs. It is important to note that the class continues to over-recover its return from a class cost of service perspective. The decrease in the LPS rate of return is a result of the additional costs being predominantly allocated on the basis of energy. As the new customer has a very high load factor (85%), more costs are pulled into the class through the allocation process.

Table 8 provides a rate of return under present rates comparison for each rate class and the entire Missouri Metro system. Keep in mind that this comparison is with current 2024 rates and a 2021 test year revenue requirement. As shown, each rate class except for the Large Power Service rate class benefits from adding the Customer. The 1.38% overall system increase in the rate of return indicates that the Customer's potential addition to the system would be a net benefit for Evergy and its current ratepayers under Scenario 2.

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Table 8: Scenario 2 Class Rates of Return

Class	Rate of Returns at Present Rates		
	TY Original Values	Including LPS Test Customer	Change
Residential	2.04%	3.51%	1.47%
Small General Service	9.08%	10.39%	1.31%
Medium General Service	10.11%	11.65%	1.54%
Large General Service	10.33%	11.84%	1.51%
Large Power Service	9.63%	8.48%	-1.14%
Lighting	9.62%	10.64%	1.02%
CCN	-55.49%	-53.78%	1.71%
MO Metro Retail	**5.88%**	**7.26%**	**1.38%**

Table 9 compares the unit costs at present rates between the original test year and Scenario 2, which includes the addition of the LPS Customer. On a per-unit basis, customer costs increase by $6.86, energy costs increase slightly, and demand costs decrease by $1.96. The demand decrease for the LPS class is a result of adding the Customer's additional 2.9 million MWh energy sales.

Table 9: Scenario 2 Unit Costs at Present Rates

Unit Costs at Present Rates			
Large Power Service Unit Costs	TY Original Values	Including LPS Test Customer	Change
Customer Costs	$118.95	$125.81	$6.86
Excluding Local Facilities	$108.63	$114.88	$6.25
Average Cost per kWh	$0.02708	$0.02999	$0.00291
Demand Cost Per Billing kW	$21.26	$19.30	($1.96)
Production Demand	$14.62	$13.38	($1.24)
Transmission Demand	$2.45	$2.19	($0.27)
Distribution Demand	$4.19	$3.74	($0.45)

Summary

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Table 10 summarizes the results at the system level under each scenario. As outlined above, the potential addition of the Customer benefits the Evergy MO Metro system and its corresponding ratepayers in both Scenario 1 and Scenario 2. As details about the customer become more available, a more detailed analysis should be conducted with a more detailed estimate of how Evergy will serve the load and additional consideration of other costs that may change.

Table 10: Rates of Return Results Summary

Class	Rates of Return at Present Rates				
	Test Year Original Values	No Generation Investment		With CCGT Investment	
		Including LPS Test Customer	Change	Including LPS Test Customer	Change
Residential	2.04%	4.03%	1.99%	3.51%	1.47%
Small General Service	9.08%	12.19%	3.11%	10.39%	1.31%
Medium General Service	10.11%	14.09%	3.98%	11.65%	1.54%
Large General Service	10.33%	14.34%	4.01%	11.84%	1.51%
Large Power Service	9.63%	10.23%	0.60%	8.48%	-1.14%
Lighting	9.62%	11.45%	1.83%	10.64%	1.02%
CCN	-55.49%	-56.25%	-0.77%	-53.78%	1.71%
MO Metro Retail	**5.88%**	**8.57%**	**2.69%**	**7.26%**	**1.38%**