BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF OTTER TAIL POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN NORTH DAKOTA

CASE NO. PU-23-342

EXHIBIT ____ (KM-3)

SURREBUTTAL TESTIMONY AND EXHIBITS OF

KAVITA MAINI

ON BEHALF OF

MIDWEST LARGE ENERGY CONSUMERS

NOVEMBER 25, 2024

116 PU-23-342 Filed 11/25/2024 Pages: 27
Prefiled Surrebuttal Testimony and Exhibits of Kavita Maini - Redacted
Midwest Large Energy Consumers
Richard Savelkoul, Martin & Squires, PA

Contents

EXHIBITS

Exhibit KM-3-1: MLEC-137 NOT PUBLIC

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Are you the same Kavita Maini that filed previously Direct and Rebuttal Testimony in this case?

A. Yes, I filed direct and rebuttal testimony on behalf of the Midwest Large Energy Consumers ("MLEC"). My direct testimony provided recommendations regarding Otter Tail Power Company's ("OTP" or "Company") revenue requirement issues, adjustment to Large General Service sales and sales adjustment rider, class cost of service study ("COSS"), revenue allocation to classes and rate design for the Large General Service ("LGS") class. In rebuttal testimony, I provided updates to the manual adjustments related to the sales forecast and responded to North Dakota Public Service Commission Staff's position on various issues.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my surrebuttal testimony is to respond to OTP's rebuttal responses regarding the following issues:

Section II: Revenue Requirement Issues

Section III: Sales Adjustment Rider

Section IV: Revenue Requirement Allocation

Section V: LGS Rate Design

II. REVENUE REQUIREMENT ISSUES

1. Langdon Upgrade

Q. What was your recommendation regarding the revenue requirements associated with the Langdon Upgrade?

A. I recommended that since the expected in-service date is close to the end of the Test Year (November 2024) and the Company has an existing mechanism to recover the costs of renewable generation through the Renewable Cost Recovery Rider (RCRR). I explained that the rider recovery will allow for savings associated with accumulated depreciation and other adjustments to rate base on an annual basis. If the costs are folded into base rates, customers will pay the higher front end loaded costs with no downward adjustments until the next base rate case.

Q. What was the Company's response?

A. Based on a review of Ms. Paula Foster's rebuttal testimony (page 2) , I understand that the Company opposes my recommendation on the basis that leaving the project in the RCRR rider would require OTP to file more frequent rate cases. Further, she indicates that folding rider costs into base rate is standard regulatory practice during rate cases. She also indicates that because the Langdon upgrade is expected to be in service in the Test Year, it should be folded in base rates and Ashtabula I, Ashtabula III and Luverne upgrades should be recovered through the RCRR rider because the expected in-service date is outside the Test Year and in 2025.

Q. How do you respond?

A. I am not persuaded by the Company's arguments due to the following:

1. Adding more costs to base rates than necessary in order to prevent the potential for another rate case is not a sound reason. Since the Company has another option to recover costs through the rider, there is regulatory certainty of cost recovery. My recommendation does not preclude OTP from recovering the costs associated with the Langdon upgrade including the Company's authorized rate of return.
2. The Langdon upgrade is expected to be in service sometime in November 2024, which implies that it not used and useful for at least 10 plus months of the Test Year. Aside from the important fact that the rider recovery will result in downward adjustments in revenue requirements over time, from a regulatory rate making perspective, rider recovery will also properly recognize the in-service date of when this upgrade will result in actually being used and useful.
3. As for the standard regulatory practice of folding rider costs in base rates, I did not oppose folding Merricourt wind project related costs in base rates since this project has been operating and in-service since 2020.
4. Regarding the repowering upgrades associated with Ashtabula I, Ashtabula III and Luverne, the reason I indicated that the cost recovery of these upgrades will also be through the RCRR is to demonstrate that the Company will continue to utilize the rider in order to recover costs faster than through another base rate case.

Q. Mr. Bruce Gerhardson asserts that I am recommending a different, formulaic approach on page 4 of his rebuttal testimony. How do you respond?

A. I am surprised and puzzled by Mr. Gerhardson's assertion that I am offering a "different formulaic approach". To be clear, I am not recommending a different approach other than the mechanisms OTP has utilized since the inception of riders in North Dakota to recover transmission, renewable generation, thermal generation, metering and environmental costs. My recommendation to recover the costs associated with the Langdon upgrade in the RCRR will continue to allow recovery of prudently incurred expenses as well as the authorized rate of return. The Company's apparent resistance to continued rider recovery for the Langdon repowering project related costs reinforces the fact that OTP wants to be able to pick and choose which mechanism provides it with the biggest benefit – that is, utilize the rider recovery for quicker recovery of costs and fold into base rates where it can set the revenue requirement at the highest cost due to the front loading of the revenue requirements, but not reduce the rate base for accumulated depreciation until it comes back for another base rate case.

Considering this case reflects a requested 10.9% increase to base rates, it would be more appropriate to permit OTP full recovery in the rider, which it advocated for and continues to use, and should not be now allowed to manipulate timing to increase their recovery.

Q. Are there other benefits to leaving Langdon repowering related project costs in the rider?

A. Yes. Aside from benefits discussed above, the potential regulatory liability associated with generating more PTCs than the levelized amounts can directly offset the rate base in the rider thereby lessening the possibility of errors. That is, it would be easier to track and calculate impacts if all the costs were included in one mechanism in order to avoid errors. This is an important benefit because there seems to be more than one instance where the utility found mistakes and needed to make follow up filings to address these mistakes.

Q. What do you recommend?

A. I continue to recommend that the Langdon project related revenue requirements be recovered through the RCRR Rider.

2. Treatment of Levelized Production Tax Credits (PTC)

Q. What was your recommendation regarding the treatment of levelized PTCs?

A. I recommended that the PTCs booked as regulatory liability be used to offset the rate base in the same manner as accumulated deferred income taxes (ADIT). This regulatory liability consists of PTC credits that have already been generated but not released to customers. For illustrative purposes and using Merricourt as an example, I calculated that the impact would be a reduction of $1.9 million in revenue requirement. I also recommended that:

- The same approach should be applied for all current and forthcoming projects that will utilize the levelized PTC treatment.
- The offsets should be credited to customers through the RCRR in the annual filings.
- The Company provide a schedule of these impacts in rebuttal testimony.

Q. How did OTP respond?

A. Ms. Foster indicated in her rebuttal testimony that that she is supportive of building the regulatory liability associated with the PTCs that have been generated and not released to customers. She testified that the regulatory liability will be included in the next

RRCR filing and that this approach will not impact the revenue requirement in this case.[1]

Q. How do you respond?

A. I can agree that there would be no impact to the revenue requirement in the rate case provided the appropriate reductions occur in the next RCRR filing. The Company did not provide a schedule to demonstrate the methodology and impacts of including the regulatory liability in the RCRR. The Company also did not address whether my calculation of $1.9 million reduction in revenue requirements associated with the Merricourt wind project related PTCs was accurate. I have issued an information request to confirm the treatment for the Merricourt wind project related PTCs in the RCRR filing and will submit it at the hearing. I recommend that the Commission require all projects subject to levelized PTCs to implement this approach in the RCRR rider.

3. Large Regional Projects (Multi Value Projects or MVPs)

Q. What was your recommendation regarding labor, external services and legal function related costs associated with MVPs?

A. I had recommended that the Company implement direct assignment of all the indirect O&M (operating; accounting, MISO fees, legal, transmission staff overhead, etc.) costs associated with the MVP investment that is designated to the FERC jurisdiction. I had indicated that OTP needs to demonstrate that such costs are assigned in a manner commensurate with the level of effort associated with developing and implementing

[1] See Ms. Paula Foster's rebuttal testimony on pages 3-4.

MVPs. If it is not practically possible to directly assign a specific cost category, I had suggested that one reasonable approach could be to base the O&M cost allocation on the level of transmission net plant in service related to MVPs as a percent of the total net transmission plant in service.

Q. How did OTP respond?

A. Ms. Amber Grenier testified that to date, all labor, external services, and legal costs have been capitalized as part of the development and construction of the MVP projects. The non-retail portion of the capitalized costs are excluded from the retail rate base. She also indicated that separate accounting structures are created for future MVP direct O&M costs to ensure that the non-retail portion will be excluded from retail rates. Finally, she also indicated that no O&M costs have occurred in the 2024 Test Year to merit an adjustment.

Q. How do you respond?

A. I appreciate OTP's efforts to create the create the separate accounting structures related to future MVP projects. However, I am concerned that all overhead, labor, outside services and legal costs are not being properly allocated to the non-retail or FERC jurisdiction. This is because MVP related costs have been incurred and are being incurred in the Test Year due to OTP's participation in the MISO workstreams related to Long Range Transmission Plan (LRTP) effort that ultimately results in MVPs. For instance, MISO indicated that since 2022, MISO held 300 formal meetings and held numerous discussions with stakeholders. Further, MISO solicits feedback regularly from stakeholders which is also labor intensive. OTP's participation in the MISO meetings help the Company to develop ideas and advocate for MVPs in its service area.

OTP, as a result of being a load-serving utility, has right of first refusal to build these lines and leads to the construction of these profitable projects. OTP could have legal, transmission related labor resources and/or outside services involved in the engagement associated with LRTP-MVP related activities. Consequently, it stands to reason that such costs should be assignable to the FERC jurisdiction in a manner commensurate with the benefits provided by the engagement at MISO.

Q. What is your recommendation?

A. As discussed in direct testimony, OTP should allocate legal, outside services and general and administrative expenses on the level of transmission net plant in service related to MVPs as a percentage of the total net transmission plant in service. Table 1 shows the derivation of the allocator along with the recommended adjustments for the expenses that were identifiable. I utilized data from the cost of service study.

Table 1 shows the derivation of the transmission net plant in service allocator at the jurisdictional level. I used this allocator to allocate general and administrative service related costs associated with transmission as well as outside services. My recommendations below result in a net adjustment of -$954,787.[2] Arguably, there could be additional adjustments for legal services, general overhead and other items, which do not appear to be in transmission categories below. However, I am not proposing additional adjustment in this case.

Table 1: Transmission Net Plant In Service Allocator and Related Adjustments

[PROTECTED DATA BEGINS…

[2] Sum of -$804,711 and -$150,478.

[redacted]

...PROTECTED DATA ENDS]

Q. Did OTP provide any additional information regarding administrative and overhead expenses?

A. Yes. I recently provided the findings above to the Company and Commission Staff and had discussions. OTP provided additional clarifications that the Company does not assign indirect general and administrative expenses to the FERC jurisdiction but rather credits retail customers through MISO Schedule 26 and Schedule 26A. Specifically, OTP provided the recently filed Transmission Cost Recovery (TCR) Rider which includes revenue credit for administrative and general expenses recovered through the MISO tariff for non-retail portion of projects qualifying for regional cost allocation or MVPs. The description regarding this credit in the TCR filing is as follows:

Revenue credit for administrative and general expenses recovered through MISO Tariff for non-retail portion of projects qualifying for regional cost allocation.

These TCRR rate update calculations include a revenue credit (reduction to TCRR revenue requirements) to account for reimbursements through MISO's Tariff for administrative and general operating and maintenance expenses. The revenue credit is for the entire amount of such revenues received through the MISO Tariff, whether related to the retail or non-retail portion of projects that qualify for regional cost allocations. This application of revenues to reduce the retail revenue requirement provides reimbursement to retail customers for any such costs that may already be recovered through Otter Tail's current retail rates.

OTP provided the credits allocated to North Dakota as shown below for 2024 and projected for 2025.

	2024			2025		
	Schedule 26A	**Schedule 26**	**Total**	**Schedule 26A**	**Schedule 26**	**Total**
Total Company	$ (1,857,696.04)	$ (1,053,616.83)	$ (2,911,313)	$ (1,588,127.96)	$ (1,007,333.93)	$ (2,595,462)
ND Share	$ (728,127.67)	$ (412,967.22)	$ **(1,141,095)**	$ (622,469.93)	$ (394,826.55)	$ **(1,017,296)**
D2	39.19520%			39.19520%		

As can be observed, these credits are substantially similar to the offset I calculated with the Company's embedded cost of service study, ($954,000). Given this latest update, which demonstrates that retail customers receive a credit of a similar amount as I estimated through the cost of service study, it is not necessary to make the adjustment I recommended above.

III. SALES FORECAST AND SALES ADJUSTMENT PROPOSALS

1. Sales Forecast for LGS Class

Q. What were your recommendations regarding sales adjustments for the LGS class?

A. As discussed in my direct testimony with updates in rebuttal testimony, the total increase associated with the three load adjustments to the revenue in the LGS class is $3,601,830. After accounting for the changes in the jurisdictional allocators and the costs to serve these loads, the net result was a reduction of $390,396 to the revenue requirement. I had recommended that these adjusted loads be included and the resulting reduction in the revenue requirement be adopted.

Q. What is OTP's position regarding this recommendation?

A. As noted in Ms. Amber Grenier's testimony, while OTP does not support including these adjustments, if they are to be included, her recommendation is the same adjustment to the revenue deficiency as I recommended in rebuttal testimony. That is, a net reduction of $390,396 to the revenue deficiency.

Q. Why does OTP prefer not to update the manual adjustments to the LGS sales?

A. Based on a review of Mr. Bruce Gerhardson's rebuttal testimony, I understand that the Company is concerned that there is little operating history associated with the three load changes.

Q. How do you respond to these concerns?

The Company's approach is to make manual adjustments to the LGS sales forecast when less information is known. For instance, in direct testimony, the Company made two manual adjustments that resulted in a decrease in the LGS sales forecast of

[PROTECTED DATA BEGINS... [redacted]

...PROTECTED DATA ENDS]

The point is that one of the primary reasons the Company makes manual adjustments is when the Company believes it has less information. So, having less operational history for the situation with new load being added is precisely the reason for the manual adjustments.

As it relates to the**[PROTECTED DATA BEGINS...** 40 **...PROTECTED DATA ENDS]** GWh reduction associated with the customer with the behind the meter installation, I received direct feedback from this customer who is also an MLEC member. The behind the meter generation has been in service since February of this year and the customer's feedback suggests that OTP's forecast from August 2023 was wrong, either without seeking input from the customer or simply not incorporating it.

[3] See Ms. Tammy Mortenson Direct Testimony on page 15.

OTP's adjustment to the customer's load was based on a 100% capacity factor for the behind the meter generation and the customer's feedback suggests that this is unrealistic, and the adjustment needs to be significantly lower. The customer (and the Company) have operational history since February 2024. Based on this case, it would seem that the Company's manual adjustment tends to err on the side most beneficial to the Company. The manual adjustment was erroneous and needs to be updated.

Q. Did you receive additional information to update the revenue deficiency adjustment?

A. Yes. In response to MLEC-137 NOT PUBLIC (**Exhibit KM-3-1**), the Company modified the net revenues (i.e., revenues after accounting for allocation related cost changes) for North Dakota Soybean food processors. The information is provided below in Table 2. The net reduction after accounting for costs is $525,400 instead of $390,396. That is, the increase in sales result in increasing sales revenues as well as costs with revenues exceeding costs by $525,400, which therefore results in reducing the revenue deficiency.by this amount.

Table 2: Revised Reduction to Base Rate Revenue Deficiency ($ Millions)

[redacted]

Q. What accounts for the adjustment?

A. OTP provided the discount to **[PROTECTED DATA BEGINS...** [redacted] **...PROTECTED DATA ENDS]** in the earlier number. I recently discovered that in approving the discount, the Commission had ordered that "OTP will not seek additional revenue to recover the gap between standard rate revenue and EDR revenue."[4] In spite of the order, OTP had not included the adjustment in the rate case. Therefore, the discount needs to be added back. As a result, my

[4] See Commission Order in docket PU-17-238.

recommendation in rebuttal testimony regarding the sharing of the discount is moot.[5]

Q. What is your recommendation?

A. I continue to recommend that the known and measurable new loads be included, and unrealistic adjustments related to behind the meter generation for one customer be corrected. The corrected manual adjustments, resulting in a net reduction to revenue deficiency of $525,400 should be incorporated.[6] My recommendations have specifically focused on the errors in the <u>manual</u> adjustments incorporated by OTP in the forecasting methodology for the LGS sales forecast. I have not made any adjustments associated with the Company's sales forecast derived through econometric analyses. As a practical matter, the manual adjustments to the forecast were based on information available in August 2023 and included in the initial application. This information needs to be corrected and new load additions in 2024 need to be incorporated in the LGS sales to reflect the latest information.

Q. Do you have another recommendation?

A. Yes. I recommend that the E- Schedules, which calculate the present rate revenues and the proposed charges, should be updated to incorporate the sales adjustments to the LGS class. I have also issued an information request asking for this information and am awaiting a response. This impacts rate design, so is necessary to make corrections so that rates can be designed correctly.

Q. While you recommend that the load additions in 2024 be annualized, you oppose

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[5] See page 4 of my rebuttal testimony.
[6] This means adding the total annualized revenues and costs resulting in a net revenue increase of $525,400. The revenue deficiency should be reduced by this net amount.

the Company's annualization of Langdon wind powering related costs. Are you not being inconsistent with your positions?

A. No. My positions are consistent because in the case of new load or load related adjustments, I am making a known and measurable change that is conventionally done in a base rate case proceeding. The annualization of Langdon repowering related costs is not necessary for the Company to recover its prudently costs.

2. Sales Adjustment Rider (SAR)Proposal

Q. What was your recommendation regarding the Company's sales adjustment proposal?

A. I recommended that the Commission reject the Company's SAR proposal. I expressed concerns about adding another rider to the long list of revenue requirement items that are currently authorized for rider recovery. I also indicated that if other jurisdictions retain the allocators from the rate cases in their respective jurisdictions, implementation of the Company's proposal only in North Dakota will result in unintended consequences.

Q. What was the Company's response?

A. Mr. Bruce Gerhardson explained that not having an SAR creates a mismatch because the rider related revenues change for the jurisdiction, but the jurisdictional allocator related costs do not change. He also indicated that the Company anticipates making a similar request in Minnesota and South Dakota in their next rate cases in those jurisdictions.

Q. How do you respond?

A. As a practical matter, there is no certainty regarding (a) if or when the Company decides to file rate cases in Minnesota and South Dakota and (b) if either of the two jurisdictions approve such as proposal. While other jurisdictions may have indicated an interest in learning more about the jurisdictional impacts, it does not automatically result in the conclusion that these proposals will be accepted. Therefore, there is no assurance that other jurisdictions will adopt such a proposal. Updating the jurisdictional allocators in one jurisdiction and not others is not reasonable. Further, given the substantive amount of rider recovery for infrastructure investments, it makes sense to revisit the full cost of service and refresh sales (and allocators) in a rate case setting. It would be counterproductive to add another rider thereby creating less incentive to update the full cost of service and recognize any O&M saving reductions resulting from infrastructure investment. If there are material changes in sales, nothing precludes the Company from the standard ratemaking process and filing a base rate case.

Q. What do you recommend?

A. I continue to recommend that the Commission reject the SAR proposal.

IV. REVENUE REQUIREMENT ALLOCATION

Q. What was MLEC's revenue allocation recommendation to classes?

A. MLEC's revenue allocation recommendation is provided in Table 7 of my direct testimony and moved most classes closer to cost compared to the Company's proposal while continuing to moderate rate impacts for certain classes. Similar to the Company, I provided relative class ratios to be applied to the final rate increase. Aside from rate moderation, I also weighed in the fairness or parity consideration as we must not ignore the important aspect that when one class is not paying their full share, one or more classes are being asked to pay more than their cost responsibility.

Q. How did the Company respond to your proposal?

A. Ms. Amber Grenier provided a comparison of the relative class ratios for OTP, MLEC and Staff on Table 2 of her rebuttal testimony. She indicated that OTP and MLEC generally follow similar patterns across the classes, though MLEC's recommendations result in more revenue being collected from the Residential class and less revenue being collected from the LGS class, as compared to OTP. Her recommendation was to adopt the Company's revenue allocation.

Q. How do you respond?

A. While it is accurate that MLEC's recommendations results in more revenue collected from the residential class and less from the LGS class, it is because MLEC's recommendation moved the residential and LGS classes closer to cost compared to the Company's proposal. Table 2 shows a comparison of the relative class ratio recommendations made by OTP, Staff, MLEC and OTP's COSS, respectively. It is worth noting that the relative class ratio for the residential class from OTP's COSS is 1.89, while MLEC's relative class ratio for this class is lower at 1.477. For the LGS class, OTP's COSS shows a relative class ratio of 0.38 for the LGS class while MLEC's recommendation is much higher at a class ratio of 0.64 in order to help temper the rate increases to other classes.

Table 2: Relative Class Ratios[7]

Class	OTP COSS Ratio of Class Proposed to Total Proposed Increase	OTP Ratio of Class Proposed to Total Proposed Increase	MLEC Ratio of Class Proposed to Total Proposed Increase	Staff Ratio of Class Proposed to Total Proposed Increase
Residential	1.890	1.284	1.477	1.150
Farms	1.160	1.287	1.200	1.305
General Service	0.760	1.196	1.000	0.933
Large General Service	0.384	0.900	0.640	0.604
Irrigation	5.220	1.338	1.600	7.687
Lighting	-2.239	-0.563	0.400	-0.641
OPA	3.554	1.432	1.600	2.113
Controlled Service (Deferred Load)	6.198	0.074	1.100	9.443
Controlled Service (Interruptible)	1.293	0.072	[illegible]	1.692
Controlled Service (Off Peak)	-2.473	0.098	[illegible]	1.564
	1.000	1.000	[illegible]	[illegible]

MLEC's recommendation is to move classes closer to parity to lower the cross subsidization between classes. It is also worth noting that Staff's relative class ratio to the LGS class at 0.60 further reinforces the reasonableness of MLEC's recommendation to this class. Further, MLEC's recommended approach also moderates the impact to the residential class compared to the COSS results.

Q. What is MLEC's recommendation?

A. I continue to recommend that MLEC's relative class ratios be applied to the final increase. Further, consistent with my discussion in direct testimony, I continue to recommend that the class revenue responsibility percent revenue responsibility share between LGS and SLGS remain the same as recommended by OTP.[8]

V. RATE DESIGN

Q. What were your concerns regarding the revenue allocation to the LGS primary

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[7] MLEC's recommendation in Table 2 is the same as submitted in my direct testimony Table 7.
[8] See Table 8 in my direct testimony.

and LGS secondary classes?

A. I was concerned that the Company's proposed revenue allocation to these classes was not directionally consistent with the Company's COSS results. Aside from fairness and cost causation concerns, an over allocation of revenue responsibility will not result in providing efficient pricing signals.

Q. How did the Company respond?

A. The Company provided Class Cost of Service Study (COSS) results to demonstrate that the recommended intra-class allocation to LGS primary and LGS secondary classes was consistent with the study results. Table 3 in Ms. Grenier's rebuttal testimony shows a comparison of the recommended revenue allocation with the COSS results. This Table shows that on an intra-class basis, of the total revenue responsibility allocated to these two sub classes, 70% is allocated to LGS Secondary and 30% to LGS Primary, respectively.

Q. Did Ms. Amber Grenier's testimony address your concern?

A. No. The Company misunderstood my concern. I could have been clearer in articulating the issue by providing more context. My concern is that the class cost of service study results show that the LGS primary and secondary classes should get a below system average increase.[9] However, as shown in the E-1 schedules, the LGS primary and secondary classes are getting a much higher than system average increase. Indeed, the E-1 Schedule shows that the revenue allocation to the LGS primary and secondary classes is **[PROTECTED DATA BEGINS...** [redacted]

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[9] The Cost of Service Study shows a 6.15% increase for a system wide increase of 10.9%.

...PROTECTED DATA ENDS] for a system average increase of 39.92% and it is the third largest increase after municipal pumping and irrigation. This proposed allocation is genuinely concerning to MLEC members and reinforces the point that the Company's approach is directionally inconsistent with OTP's own COSS results. MLEC's recommended revenue allocation to class with a relative class ratio to the LGS class of 0.64 as compared to the Company's 0.90 will help in achieving a below system average increase for the LGS primary and secondary class.

Q. Do you have any concerns with the intra class revenue responsibility assignment of 70% to the LGS Secondary and 30% to the LGS Primary class?

A. No.

Q. What was your concern regarding the rate design charges applicable to the LGS Primary and Secondary classes?

A. I was particularly concerned about the changes in the winter energy charges which were guided by a marginal cost study that was conducted in August 2023. OTP proposed to increase the winter energy charge by 79%. As I noted in my direct testimony, the marginal cost study relied in large part on the forward curve to provide a forecast for energy charges and the forward curve expectations change frequently based on a wide array of market related factors and represent the expectations at the specific moment in time. Consequently, the marginal study results are outdated.

Q. How did the Company respond to your concerns?

A. Ms. Amber Grenier's rebuttal testimony did not address my concerns about the marginal cost study.

Q. Were you also concerned about the winter demand charges?

A. Yes. I was concerned about the increase in the winter demand charges because the proposed change was to make a substantive movement of these charges from being lower than summer charges to exceeding the proposed summer charges.

Q. How did the Company respond to this concern?

A. Ms. Grenier testified that I have previously advocated for recovering more costs from demand charges.

Q. Are you now advocating for recovering less from demand charges?

A. No. I was more concerned about the large swing in the pricing signal associated with the winter demand charge. To be clear, I continue to advocate for higher fixed cost recovery from demand charges relative to energy charges.

Q. What is your recommendation regarding the demand charges?

A. Since MISO has implemented a seasonal construct, my recommendation is to equalize the summer and winter demand charges.

Q. What is your recommendation regarding the energy charges?

A. I recommend a more gradual approach to increasing the ratio between the winter and summer energy charges. At present, the ratio between winter to summer energy charges for LGS secondary and primary is approximately 1.02. I recommend that this ratio be increased to 1.05 instead of the 1.20 ratio that is proposed by the Company, which is very substantive. The revenue requirement to be recovered would be the same in both cases. My recommended ratio will continue to result in winter energy charges being higher than summer charges but with a lower differential between the charges compared to the Company's proposal.

Q. What are the specific charges you recommend?

A. Since the revenue requirement is likely to be lower than the Company's initial proposal, I would like to work collaboratively with the Company to finalize these charges. From an overall guidance perspective, I am most concerned about the large increases in energy charges, which are essentially being used to recover fixed costs that do not vary with energy consumption. The fuel and purchased power costs that vary with energy consumption are being recovered via the energy charges in the Energy Adjustment Rider. Therefore, depending on the revenue requirement reductions. my recommended approach is to make larger reductions to the energy charges. Once again, I would like to work with the Company to finalize the specific rate charges.

Q. Does this conclude your surrebuttal testimony?

A Yes.

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: November 07, 2024
Date Due: November 22, 2024
Date of Response: November 22, 2024
Responding Witness: Amber Grenier, Manager, Regulatory Economics, 218-739-8728

Data Request:
Refer to response to MLEC-135:

a. Please separate out and provide the impacts associated with each load change : (1) North Dakota Soybean Processors; (2) **[PROTECTED DATA BEGINS… … PROTECTED DATA ENDS]**. Please provide a narrative explanation and the quantitative details in excel spreadsheet format with formulae intact.
b. Please provide the calculation of the discount to North Dakota Soybean Processors under the Economic Development Rate Rider. Please provide a narrative explanation and quantitative data in an excel spreadsheet format with formulae intact.

Attachments: 1
Attachment 1 to DR ND_MLEC_137_PUBLIC.pdf

Response:

DR ND-MLEC-137 and Attachment 1 to DR ND-MLEC-137_NOTPUBLIC contain trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, DR ND-MLEC-137 and Attachment 1 to DR ND-MLEC-137_NOTPUBLIC contain customer-specific information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

a. Table 1 below separates out the impacts associated with each load change if included in the 2024 Test Year. As discussed in OTP's Rebuttal Testimony, OTP does not support including these load changes into the 2024 Test Year, as each lacks operational history to establish a high degree of confidence regarding actual usage going forward. Please see Attachment 1 to DR ND-MLEC-135_NOTPUBLIC for the excel spreadsheet format with formulae intact.

Table 1
Revenue and Allocator Effect on 2024 Test year Non-Fuel Base Rate Revenue Deficiency
($ Millions)

Component	**ND Soy**	**Customer 2**	**Customer 3**	**Total***
	[PROTECTED DATA BEGINS…			
Present Non-Fuel Revenue**				$3.737
Costs Due to Allocator Changes				$3.340
Operating Income Deficiency				$0.397
Incremental Taxes				$0.128
Net Effect to 2024 Test Year Non-Fuel Base Rate Revenue Deficiency				**$0.525**
			… PROTECTED DATA ENDS]	

* Total column may not equal the sum of the customer columns due to the compounding changes to allocation factors.
** Present non-fuel revenue calculated at standard rates and does not reflect authorized Economic Development Rate discounts.

Please note, the results in Table 1 are different from Table 1 in the Rebuttal Testimony of OTP Witness Ms. Amber M. Grenier because Table 1 present revenues are calculated at standard rates, while Table 1 of Ms. Grenier's Rebuttal Testimony reflected authorized Economic Development Rate discounts.

b. Attachment 1 to DR ND-MLEC-137_NOTPUBLIC for the calculation of the discount to North Dakota Soybean Processors under the Economic Development Rate Rider in an excel spreadsheet format with formulae intact. Under Section 14.13 of OTP's North Dakota tariff, the Economic Development Rate Model (EDRM) is only to be provided to the Commission Staff to confirm OTP's calculation of the proposed EDR.