

STATE OF MINNESOTA
BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 50
St. Paul, Minnesota 55101-2147

In the Matter of Otter Tail Power Company's Transmission Cost Recovery Rider Including the Proposed 2010 Transmission Factor	MPUC Docket No. E-017/M-09-881
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COMMENTS of the MINNESOTA CHAMBER OF COMMERCE

The Minnesota Chamber of Commerce (“Chamber”) appreciates the opportunity to comment on petition filing made by Otter Tail Corporation, d/b/a Otter Tail Power Company (“Otter Tail”) to the Minnesota Public Utilities Commission (“Commission”) requesting approval of a Transmission Cost Recovery Rider Including the Proposed 2010 Transmission Factor (“TCR Rider”).

The Chamber represents over 2,500 businesses throughout the state of Minnesota, of which a significant portion are within the Otter Tail service territory. As a result, some Chamber members will be paying for the TCR Rider proposed by Otter Tail. The Chamber deals with statewide issues at a policy level, as well as concerns businesses have with respect to doing business or continuing to do business within the state, such as having competitively priced, reliable and environmentally sound energy rates. Energy is one of the Chamber’s focal points in terms of making Minnesota’s business environment more competitive relative to other states and nations.

Otter Tail petitioned the Commission on July 28, 2009 for recovery of transmission investments made to its system under Minn. Stat. §§ 216B.16, subd. 7b and 216B.1645. Otter

Tail proposes to recover \$1,027,642 in revenue requirements. The breakdown of these revenue requirements is as follows:

<u>Proposed 2010 Revenue Requirements</u>	
Langdon/Hensel Line	\$545,573
Appleton/Canby Line	\$268,246
Schedule 26	\$170,658
Carrying Cost	<u>\$43,165</u>
Total	<u>\$1,027,642</u>

For the Chamber's members, this proposed Rider would result in a roughly 1% increase of their total bill. Costs associated with transmission upgrades are expected to increase to unprecedented levels, as a result of increasing regional investment related to wind generation integration at MISO and Cap-X 2020 in addition to Otter Tail related infrastructure needs. Consequently, it can be anticipated that OTP's revenue requirements associated with this Rider will be significant in future years. The Chamber urges the Commission to render decisions on this proceeding by paying special attention to implications of Otter Tail's proposal on future cost recovery associated with this Rider.

The TCR Rider petition filing submitted by Otter Tail raises the following three, material concerns that are precedent setting and should be addressed both, with with respect to the implications on the current rider as well as implications on future cost recovery:

1. Lack of review regarding cost prudence related to the Langdon/Hensel Line located in North Dakota;
2. Distortion of pricing signals in the rate design for the LGS class by allocating 84% of the fixed and demand related costs to the energy charge; and
3. Inadequate approach in managing Schedule 26 related costs, as these costs increase to unprecedented levels in the future.

For the reasons discussed below, the Chamber recommends that (1) these investments be reviewed for prudence in OTP's next general rate case, regardless of addition to rate base (2) all transmission related costs be recovered from the demand charge in the rate design for the LGS class, and (3) if Schedule 26 costs are to be recovered through the Rider, (a) the revenues must flow to customers as received (b) if costs exceed revenues by a capped amount, such costs should be recovered over a longer period to mitigate the costs impact for customers.

Transmission costs are expected to increase to unprecedented levels owing to expansions related to Cap-X 2020, integration of wind generation to fulfill RPS standards, and Otter Tail's needs. Exhibit A shows a sample of projects that are in the MISO "pipeline" to demonstrate the magnitude of expected costs in the future. All projects in Appendix A have been examined and approved by MISO staff. Projects in Appendix C are at the conceptual stage. The Fargo-St. Cloud project alone is estimated at \$490,000,000. Based on MISO's estimates, OTP's share for this project is close to \$80 million. Consequently, it is crucial that decisions made regarding the TCR Rider keep these forward looking costs and their magnitude in perspective.

1. PRUDENCY REVIEW OF LANGDON/HENSEL LINE

The Chamber is concerned with the lack of review of a significant portion of costs to be recovered under this rider, such recovery, if allowed immediately through the rider should be an exception, not a rule. The Langdon-Hensel Line has reviewed no MISO recovery because it was not built by a MISO member (built by MinnKota, not OTP) and reviewed no North Dakota prudence review (if built in Minnesota Certificate of Need would have been required), but accounts for a 61% share of revenues, which OTP hopes to collect from MN ratepayers under OTP's proposed TCR. The Langdon-Hensel 115 KV project is a joint project with Minnkota with a total cost of \$ 11.2 million and OTP's share to be recovered in the rider is \$3.82 million.

OTP notes that ND does not require certificate of need for a project to be designed and operated at 115 KV or less, so the project has received no review with respect to dollars spent or how they are allocated between MinnKota and OTP. Further, note that no MISO approvals are cited even though MISO has an ongoing queue procedure to study new transmission requests.[NONE ARE CITED OR NONE WERE OBTAINED, BECAUSE NOT REQUIRED BECAUSE BUILT BY MINNKOTA?] If it would have gone through the MISO approval process, an analysis to determine who should pay for the new transmission project project would have taken place. Example MISO classifications include: Network Integrated Transmission Service ("NITS"); Energy Resource Interconnection Service ("ERIS"); Network Resource Interconnection Service ("NRIS"); or others, any of which would affect how and from whom the joint utilities recover these costs. There is no justification in the filing, for example, that the Langdon-Hensel project should not be considered generator outlet and shared by other parties purchasing output from the Langdon wind farm.

We note that in OTP's Luverne Wind Project filing under MPUC Docket No. E017/M-09-883, made on July 25, 2009, OTP has made a MISO Transmission Service Request (TSR) and MISO is making a study of 13 miles of 230 KV line to be included as generator outlet under MISO guidelines – this seems inconsistent with OTP's request for recovery of this investment. The result of the MISO TSR proceeding results in other participants sharing in the 230 KV line costs. Which could be the result if the Langdon - Hensel 115 KV line was classified as generator outlet under the MISO system or at least could result in an allocation different than the MinnKota split OTP is proposing.

It is our understanding that OTP indirectly avoided MISO study and approval because Minnkota, the project manager, is not a transmission owning member of MISO (and neither is

WAPA [WHAT IS THE RELEVENCE OF WAPA?]), so each has its own set of transmission tariffs and its own queue for developers. Since each also has no "seams" agreement with MISO there is no procedure to prevent pancaking of transmission rates and no MISO procedure requiring advance study of new generation and transmission via application via the MISO queue. However, OTP and MDU are transmission owning members of MISO within these adjacent and overlapping service territories and are subject to MISO queue and application procedures. [WHAT IS THE RELEVENCE OF MDU?] By Minnkota being a "middleman", the Langdon-Hensel project avoided the MISO queue.

Additionally, a recent municipal trade publication states that Minnkota is a broker for sales out of the Langdon wind farm (constructed by NextEra, previously called Florida Power and Light Energy) to the Northern Minnesota Power Association (NMPA) as well as to OTP.

[RELEVENCE OF THIS PARA?]

Lastly, since this asset is not within the MISO system, there may be a lack of proper "Seams" Agreements, regardless Langdon-Hensel project may also earn wheeling revenues, which must be shared with MN ratyepayers.

There is no indication that the amounts included in OTP's TCR application are inappropriate, but it would appear that the project, which has avoided ND and MN Commission review, as well as MISO review should be put through a prudency review prior to final recovery, which review is most apporprate, in this case, within OTP's next rate case.

2. TCR RIDER CHARGE DEMAND ALLOCATION

All costs related to Otter Tail's proposed revenue requirements for the TCR Rider are fixed in nature. [Otter Tail correctly allocates according to classes based on demand usage] Otter Tail appropriately allocated the total revenue requirements at the inter class level using the D2

allocator. However, in the proposed rider design for recovery herein, it split the allocation 84%-16% to energy and demand respectively within the LGS class.

This intra cost allocation does not follow the cost driver incurred and results in sending an incorrect and distorted price signal to the LGS customers. The problem will be further exacerbated as transmission costs increase significantly as noted earlier. The result is that high load factor customers are penalized as they pay a disproportionate share of the costs when compared to the costs they impose on the system. It is crucial that all fixed charges associated with transmission upgrades be recovered 100% via the demand charge.

The 100% recovery through the demand charge, as proposed by the Chamber, will reflect cost to serve at the intra-class level and will match the manner in which the charges are allocated at the inter class level. In Xcel Energy's case deliberations regarding the TCR Rider, the Commission ruling was as follows:

- a. State that it may be appropriate to develop a demand-based charge for TCR rider in the future if significantly higher levels of costs are to go through the TCR in the future.(E002/GR-09-1065 – Section V.B.1)

Since the approved MISO projects indicate substantial costs in the future, the Chamber urges the Commission to set the use the correct methodology in this proceeding now, so that costs are recovered entirely through a demand charge.

3. SCHEDULE 26 COST RECOVERY

Otter Tail proposes to recover Schedule 26 related costs through the TCR Rider. As described in the utility's petition, these costs are associated with shared costs of transmission related investments at MISO and termed RECB (Regional Expansion Criteria and Benefits) costs. Cost allocation for RECB related costs varies by type of project:

- MISO approved baseline Reliability Projects (to ensure reliability) that are 345 KV and above and that have a project cost greater than \$5 million are 20% socialized across the MISO footprint. The remaining 80% are allocated on a sub-regional basis based on a system power flow analysis that typically results in allocating costs to pricing zones in close proximity to the proposed transmission facility.
- MISO approved regionally beneficial projects (for economics) that have a project cost of greater than \$5 million are 20% socialized and 80% is allocated as applicable to each pricing zone within each of the three Planning Sub Regions (East, West and Central). So far, no project listed in the MISO expansion plan has been approved as a regionally beneficial project.
- MISO approved generator interconnection projects assigns 50% of the costs responsibility for the network upgrade to the transmission owner in the current tariff. Note that in the last year, Otter Tail submitted a letter to exit MISO on the basis that the myriad of proposed generator interconnection projects in its control area were wind generators that were being constructed for benefits elsewhere outside its control area. Consequently, Otter Tail felt that it was paying for costs that were not commensurate with the benefits to its ratepayers. MISO submitted a temporary solution in a filing to FERC whereby 90% of the costs would be borne by the generator, until a more permanent solution can be vetted through the MISO stakeholder process. FERC has not ruled on this issue yet. Consequently, a great deal of uncertainty surrounds the treatment of generator interconnection projects and OTP's participation in MISO.

As demonstrated in Exhibit A, costs associated with shared projects can be material amounts. Note the Cap-X 2020 and Bemidji projects approved in MISO's Appendix A [which are listed...](#) and the Green Power Express project in Appendix C, which is listed at an expected cost of \$12.4 billion. [MISO is in the process of determining cost allocation methodology for projects such as Green Power Express, where the generation is located remotely. Consequently, there is a great deal of uncertainty regarding how such cost sharing will ultimately occur.](#)

Due to the unknown nature of cost sharing associated with large regional transmission, infrastructure projects going forward, and as well as, the known cost sharing for significant regional investment currently approved, there are two reasonable options to choose from for recovery of Schedule 26 related costs:

1. Defer the costs and revenues and their treatment until there is more certainty regarding the issues stated above; note that MN statute §216B.16 Subd. 7b (b)(2) authorizes the Commission to “accept, reject or modify” a tariff that allows recovery of MISO related RECB charges.
2. If the Commission wants to allow recovery of such costs in this instant proceeding, the revenues should also flow through as received by Otter Tail. In addition, the Commission should set trigger mechanisms to spread net costs (i.e., excess costs over revenues) over a larger number of years to mitigate rate impacts to customers. [\[reflective of capital improvements? Why a jump that would not be sustained\]](#) For example, if the costs exceed revenue by \$1 million to \$5 million, the costs should be spread over 5 years and if the costs exceed revenue by \$5 million to \$10 million, the costs would be spread over 10 years and so on. Since it is already known that transmission costs are going to be significant and there does not appear to be a way of gauging revenues, as acknowledged by OTP, it is reasonable to spread these costs over a longer period of time. This blunted cost allocation was utilized in OTP’s renewable recovery rider.

WHY IS THIS IMPORTANT NOW RATHER THAN WHEN RATES JUMP... NOTHING TO CURRENTLY DEFER AND CHARGES NEED TO COME BACK B4 RECOVERED?

Since recovery of Schedule 26 related costs are going to have far reaching implications in the future and are going to be potentially very significant going forward, the Chamber urges the Commission to implement our recommended options as described above.

3. Recommendations

In summary, The Chamber's recommendations are as follows

1. Langdon-Hensel Line requires prudence review at time of OTP's next rate case regardless of the project recovery through base rates.
2. Charges related to the TCR Rider must be included in the demand charge of the LGS rates
3. Either defer Schedule 26 costs until there is most certainty on cost sharing treatment or if Schedule 26 are allowed to be recovered through the Rider, flow through Schedule 26 revenues as Otter Tail receives them and modify treatment to spread cost recovery over a period of 5 to 10 years if costs exceed revenues by a specified capped amount

Dated: October 8, 2009.

Respectfully submitted,

By: _____

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