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June 27, 2013

Dr. Burl Haar
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of the Petition of Otter Tail Power Company for Approval of a Transmission Cost Recovery Rider Annual Adjustment
Docket No. E017/M-13-103
REPLY COMMENTS

Dear Dr. Haar:

Enclosed for filing in the above-referenced matter are Otter Tail Power Company's ("Otter Tail") Reply Comments.

Otter Tail has electronically filed this document with the Commission which, in compliance with Minn. Rule 7829.1300, subp. 2, also constitutes service on the Department of Commerce, Division of Energy Resources and the Office of Attorney General-Residential Utilities Division. A Certificate of Service is also enclosed.

If you have any questions regarding this filing, please contact me at 218-739-8279 or at stommerdahl@otpco.com.

Sincerely,

/S/ STUART TOMMERDAHL
Stuart Tommerdahl
Manager, Regulatory Administration

dm
Enclosures
By electronic filing
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Petition of Otter Tail Power Company for Approval of a Transmission Cost Recovery Rider Annual Adjustment

Docket No. E017/M-13-303

OTTER TAIL POWER COMPANY'S REPLY COMMENTS

I. INTRODUCTION

These Reply Comments respond to Comments filed by the Department of Commerce, Division of Energy Resources ("Department") on May 24, 2013 in the above–captioned matter. In their Comments, the Department identified a number of items to which Otter Tail Power Company ("OTP") was asked to respond. In these Reply Comments, OTP will provide details on the anticipated cancelation of the Sheyenne-Audubon 230 kV line upgrade ("Sheyenne Project" or "Sheyenne Line"), address the Department's questions with regard to MISO Schedule 37 and 38 revenue forecasts, confirm the Department's understanding of Attachment O revenues, discuss the issue of cost recovery caps within OTP's Transmission Cost Recovery Rider ("TCRR"), and address the inclusion of internal costs within the TCRR. OTP also addresses a recent compliance obligation regarding the appropriateness of the use of carrying charges within a Rider.

II. SHEYENNE – AUDUBON 230 KV LINE UPGRADE NO LONGER NEEDED

OTP sought recovery of three new transmission projects in the initial Petition in this Docket filed on February 7, 2013. These projects were deemed eligible for recovery in OTP's TCRR by the Minnesota Public Utilities Commission ("MPUC" or "Commission") in its Order dated March 15, 2013 in Docket No. E017/M-12-514 ("12-514"). Subsequent to both the initial Petition in this Docket and the March 15 Order in Docket 12-514, the decision was made to cease further development of the Sheyenne project. This decision was based on additional transmission studies that indicated the Sheyenne Project was no longer needed to support the interconnection of the Luverne and Ashtabula wind farms due to a separate regional transmission project near the point of interconnection. The following provides further background leading up to this decision.

The need for the Sheyenne Project arose from the first phase of interconnection studies completed by Minnkota Power Cooperative ("MPC") in 2008 for the interconnection of the Luverne and Ashtabula wind farms. These studies focused on projected near-term transmission system operating conditions during the 2010 timeframe. As a result of these studies, the Sheyenne Project was identified. In order to allow interconnection of the wind farms in an expedited manner, and to determine the status of other pending projects under development at the time of these interconnection studies, a temporary wind adjusted rating was implemented in mid-2009 to prevent the Sheyenne Line from overloading during real-time operating conditions. One of the pending projects under development at the time of these interconnection studies was the CapX2020 Fargo – Monticello 345 kV line ("CAPX Fargo").

The MAPP Design Review Subcommittee ("DRS") required additional interconnection studies be conducted to evaluate out-year transmission system conditions as part of the project approval process. This study was completed in 2012 by MPC and focused on the 2017 time-frame. A key assumption in this out-year study was the operation of the CAPX Fargo line, which is scheduled to be energized in 2015. The out-year study showed that with the CAPX Fargo line in service, flows along the Sheyenne Line would be reduced to levels below the existing rating of the facility, therefore eliminating the need to upgrade the Sheyenne Line.

The Mid-Continent Independent System Operator ("MISO") has reviewed the additional study material from MPC and confirmed in March 2013 that the addition of the CAPX Fargo project will be sufficient to relieve the Ashtabula and Luverne wind farm owners from the upgrade obligation of the Sheyenne Line. OTP, as the transmission owner of the Sheyenne Line, agreed with MISO's conclusion and, in the March 2013 timeframe, began the process of cancelling the Sheyenne Project. MISO is now expected to move forward with amending the existing Facility Construction Agreement ("FCA") to remove the requirement of the Sheyenne Project and instead, require wind adjusted ratings for the Sheyenne Line with an accompanying operating guide until the CAPX Fargo project is in-service. OTP is currently working with MISO and MPC to amend the FCA and expects that process to be completed in the next few months. In the end, OTP anticipates it will have incurred less than $15k in project development costs associated with this project. All costs have been removed from the TCRR.

III. FORECAST MISO SCHEDULE 37 AND 38 REVENUES INCLUDED IN SCHEDULE 26 FORECASTS

The Department noted in Section D of its Comments that there were no MISO Schedule 37 and 38 revenues included in the forecast information provided in Attachments 2 and 13 of the Petition. In the calculation of the annual revenue requirements under Attachment GG, MISO determines the applicable financial obligations of American Transmission Systems, Incorporated ("ATSI"), Duke-Ohio ("DEO") and Duke-Kentucky ("DEK"). However, MISO does not provide a separate Schedule 37 and 38 revenue forecast, but instead includes the forecast for these revenues as part of the overall Schedule 26 revenue forecast. MISO does report the Schedule 37 and 38 revenues on an actual basis, and OTP includes these within the tracker just as other actual amounts within the tracker are updated on an on-going basis.

IV. ATTACHMENT O REVENUES

In Section F of the Department's Comments, the Department requested confirmation of its understanding of Attachment O revenues related to Regional Expansion Criteria Benefits ("RECB") projects and Multi-Value Projects ("MVPs"). The Department is correct in its understanding. OTP does not receive any other revenues (besides those revenues received under MISO Schedules 26/26A) from other parties for their use of OTP's RECB and MVP transmission lines. The revenue requirements calculated under Attachment GG and Attachment MM for the RECB and MVPs, respectively, are carved out of the Attachment O calculation.

V. RESPONSE TO THE DEPARTMENT'S RECOMMENDATIONS TO LIMIT THE AMOUNT OF CAPITAL INVESTMENT INCLUDED IN THE RIDER TO CERTIFICATE OF NEED ESTIMATES AND TO EXCLUDE CAPITALIZED INTERNAL LABOR

The Department makes two recommendations to limit the capital costs included in the TCRR. The first recommendation is that the capital costs used in the TCRR should be capped at the planning estimates cited in the Certificate of Need ("CON") proceeding for each project (if no CON was issued, then in the Eligibility Determination); the second recommendation is that the TCRR should not include internal capitalized labor costs in the total amount of investment used for the Rider recoveries.

These Reply Comments address each of the Department's recommendations in the following sections. In short, Otter Tail does not agree that capping of costs to CON estimates or limiting recovery of capitalized internal costs would be appropriate. As will be further explained below, CON planning estimates are by their nature preliminary and made without the benefit of routing information or final design engineering. For these reasons, they have not historically been viewed as an upper limitation on prudence and using them in this way could not have been reasonably contemplated at the time of the CON applications. Also, as will be further explained below, creating limitations on recovery of capitalized internal costs is neither appropriate nor in the public interest.

A third (but perhaps less intuitive) reason for not making adjustments to the capital costs included in the TCRR, is the related impact that the removal of such costs has on the amount of corresponding revenue credits applied to the TCRR that are based on those capital costs. In these Reply Comments, OTP will illustrate how capping or limiting the amount of capital investment included in the TCRR will actually result in higher TCRR rates, not lower rates, due to the removal of revenue credits that correspond to the level of investment.

Because each of the two recommendations proposed by the Department would result in reductions in recoverable costs (capping costs or disallowing internal costs), these Reply Comments will first explain more clearly the impact such reductions would have on the corresponding revenue credits that currently serve to reduce TCRR rates.

A. INCLUDING ALL CAPITAL COSTS AND CORRESPONDING MISO REVENUES RESULTS IN LOWER TCRR RATES.

While in most Rider circumstances reducing the amount of capital investment included in a Rider would reduce the Rider Rates, in this instance, TCRR rates will <u>*increase*</u> if the amount of capital investment is reduced. The following will help explain why this occurs.

All but one of the transmission projects included in OTP's TCRR are regionally cost-allocated projects that receive revenue through the FERC-approved MISO tariff. These MISO revenues are credited to the TCRR, reducing the TCRR revenue requirement.

In this way, by investing in such projects, OTP has reduced the amount OTP's customers currently pay for the projects. To help illustrate how investing in such a project reduces the cost to retail customers, Table 1 below compares what OTP customers currently pay for the Bemidji –

Grand Rapids ("B-GR") project (with OTP as an investor in the project) with what customers would have paid had OTP not invested in the project:

Table 1

	Bemidji–Grand Rapids Project Revenue Requirements 2013	
	With OTP Investment	**No OTP Investment**
Schedule 26 Expense[1]	1,228,463	1,228,463
MN Revenue Requirements[2]	1,447,707	0
Schedule 26 Revenue[3]	(1,879,798)	0
Total	796,372	1,228,463

As Table 1 illustrates, it is very beneficial to OTP's customers for OTP to invest in these regional projects and for the project costs and revenue credits to be included in the Rider rate calculations. Also, because the revenue credits are currently larger than the corresponding TCRR revenue requirements, the effect of reducing the amount of capital investment in the TCRR has what might appear a counterintuitive effect: the TCRR rates will *increase* as the total amount of capital investment reflected in the Rider *decreases*. The only way that a reduction in capital investment could result in a reduction to TCRR rates would be if the capital investment used for the Rider's revenue requirement calculation was reduced but the capital investment used to calculate the corresponding revenue credits was not reduced. Such an approach would be an artificial and inappropriate mismatching of the investment recognized in the TCRR for the two rate calculation components. It would essentially allow the TCRR to capture revenues from investments that are not being paid for through the TCRR. Such a mismatching would not be consistent with standard ratemaking treatment and the result would serve as a significant disincentive for OTP and other utilities to invest in these projects despite the benefits illustrated

[1] Minnesota's share of MISO's allocation of costs to OTP for B-GR based on OTP's retail load requirements.
[2] The Minnesota revenue requirement for B-GR is based on OTP's total investment in the project.
[3] Minnesota's share of MISO's allocation of revenues to OTP for B-GR is based upon OTP's total investment in the project.

in Table 1. Such a mismatching would also be inconsistent with the Commission's ruling in OTP's last TCRR update that increased the amount of investment included in the TCRR for the purpose of increasing the corresponding credits, as will be explained further below.

Fundamentally, it should be recognized that one of the most beneficial aspects of the TCRR is that it provides a retail ratemaking mechanism that syncs up with the FERC-approved MISO rate mechanism for regionally allocated transmission investments. The MISO tariff allows a utility to recover on a current basis its annual revenue requirement for investments made in qualifying transmission facilities. Similarly, the Minnesota TCRR provides a retail mechanism that allows for the recovery of eligible investments. To avoid a double recovery on TCRR eligible transmission investments that also qualify for MISO regional recovery, the MISO revenues coming into the utility for those investments are applied to the TCRR as an off-setting revenue credit, thus reducing the amount that needs to be recovered from OTP retail customers.

As indicated above, this approach of including in the TCRR calculations <u>all</u> of the capital investment used in the MISO tariff mechanism was specifically addressed by the Commission in its Order in OTP's last annual TCRR Update. In its final Order in that Docket, the Commission addressed the question of how much of OTP's investment in regional projects should be included in its TCRR (the entire investment or only the amount that corresponds to retail service). The Order states:

> *"The Commission will apply standard ratemaking treatment to the costs of the Bemidji and Fargo transmission lines. <u>All Minnesota-jurisdictional costs of the two lines will be included in the rider and all revenues attributable to the Minnesota-jurisdictional portions of the lines will be credited to ratepayers</u>."*[4]

That Commission decision recognizes that while it would typically increase rates to add more capital investment to the TCRR, doing so in the case of these regional projects actually reduces current TCRR rates. The decision also explicitly recognizes that synchronizing the two mechanisms requires that the costs of projects included in the TCRR and revenue credits attributable to those costs must match.

For these reasons, the capital costs included in the TCRR for OTP's eligible transmission project investments should not be reduced as proposed by the DOC. If costs are excluded from the TCRR revenue requirement calculation, then principals of matching would require that the

[4] Commission Order in Docket No. E-017/M-10-1061, Page 5, B. Commission Action, Paragraph 1.

revenue credits that correspond to the excluded costs should also be excluded. As described above, because OTP's TCRR projects are predominantly projects that qualify for MISO regional cost allocation, such an approach would result in higher TCRR rates.

B. EXPLANATION OF PROJECT COSTS AND CON ESTIMATES, AND EXPLANATION OF WHY INVESTMENT INCLUDED IN THE RIDER SHOULD NOT BE CAPPED AT THE PLANNING ESTIMATES USED IN CON PROCEEDINGS

OTP provided the Department with the following table in response to Department Information Request No. 4, which requested information on cost estimates referenced in CON and Eligibility proceedings for projects to be included in the TCRR:

Table from OTP Response to DOC IR #4.

Project	CON Docket #	TCR Eligibility/ Update Docket #	TCR Eligibility/ Update Amount (millions)	OTP Ownership Percentage	OTP's Share of Approved Costs (millions)
Fargo-Monticello	06-1115	E017/M-10-1061	$640.0	13.2%	$84.5
Bemidji-Grand Rapids & Cass Lake	07-1222	E017/M-10-1061	$111.5	20.0%	$22.3
Brookings-Hampton	06-1115	E017-M-12-514	$669.6	4.1%	$27.5
Ramsey	N/A	E017-M-12-514	$0.9	100.0%	$0.9

In its Comments, the Department requested additional clarification of the planning estimates cited in the CON Dockets listed (as opposed to amounts cited in eligibility and prior update proceedings). The following explanation is intended to provide that clarification.

The cost estimates listed for the Fargo-Monticello and the Brookings-Hampton projects are amounts included in the respective CONs for those projects; the amounts used in the eligibility Docket cited in the table were not changed from the respective CONs for those projects. The Ramsey project did not require a CON but initial cost estimates were provided in the Eligibility Filing Docket (Docket No. 12-514) noted in the table above.

For the Bemidji-Grand Rapids project[5] (B-GR), OTP provided the amount $111.5 million in the table, which was the amount approved for recovery in OTP's last TCRR Update (Docket No. E017/M-10-1061). As indicated above, in that proceeding the Commission addressed whether it was appropriate and beneficial to include more or less of the costs of the B-GR project (and the Fargo-Monticello projects) in the TCRR, and the Commission ruled that all costs should be included. While the Department's recommendation to cap costs at the level of the CON estimates was not raised in the proceeding, such a reduction in costs would have been directly contradictory to the Commission's ruling to include all costs so that all revenues could also be credited to the TCRR. There are several additional reasons that it would not be appropriate to reduce the total costs of the B-GR project in the TCRR based on CON planning estimates. Those additional reasons are explained below.

The B-GR project was jointly developed, with OTP owning 20 percent of the project. The Application for a CON for the project was filed on March 17, 2008 in Docket E017, E015, ET-6/CN-07-1222. The CON was approved in an Order dated July 14, 2009. The project construction was completed and the facility went into service as of September 2012.

The Application in the CON proceeding contains the following description of the estimated costs of the project:

> "3. 3 Estimated Cost
>
> Depending on the terrain crossed, the cost of construction for this 230 kV line is estimated to be in the range of $675,000 to $915,000 per mile in 2007 dollars (excluding right-of-way acquisition, permitting, and other ancillary costs). The cost of 230 kV substation upgrades is estimated to be approximately $1 to $1.5 million per substation. The length of the proposed Bemidji-Grand Rapids 230 kV Line along the Utilities' preferred corridor is approximately 68 miles, and based on the projected number of miles of the line that would be constructed on wooded and wetland terrain, the estimated cost for line construction is about $58 million. Another $2.5 million is estimated to upgrade the Wilton Substation near Bemidji and the Boswell Substation near Grand Rapids, for a total estimated construction cost for the Project of $60.5 million." (CON Application at 16).

[5] As noted in OTP's initial Petition in this Docket, the Cass Lake project was included in the Bemidji-Grand Rapids revenue requirements calculation in the previous TCRR Update filing. In order to more closely resemble MISO Attachment GG project breakdowns, OTP has separated the Cass Lake project from the Bemidji-Grand Rapids project in its Petition.

As the description makes clear, the project is a planning estimate, made before a route has been selected, before project design is conducted and before any knowledge of construction conditions, terrain, etc. can be reasonably assessed. For some project cost components the CON application references that such costs will be incurred, but no estimate is provided; for example the CON application explicitly identifies that certificate of need, route permitting, legal, environmental permitting and right of way costs will be incurred, but no quantification of those costs is included in the estimate.

Additionally, as noted in the Department's Comments in this TCRR proceeding, planning estimates in a CON proceeding are generally used to assist in making comparison of the alternatives that are being examined. In the case of the B-GR CON, the planning estimates used for all of the alternatives considered were made on a similar basis. In its Comments in the CON proceeding, the Department concluded this approach of arriving at construction cost estimates for the proposed project and alternatives was reasonable. Those Comments state:

> "Regarding detailed cost analysis, the Applicants performed a detailed cost analysis of four different alternatives:
>
> - the proposed facility;
> - a Winger-Wilton 230 kV line;
> - a Badoura-Wilton 230 kV line; and
> - rebuild existing 115 kV lines.
>
> Key inputs to the Applicants' cost analysis of the four alternatives are:
> - 15 percent required reserve ratio;
> - $700/kW installed cost of generation;
> - 11.92 percent fixed charge rate for generation;
> - 11.73 percent fixed charge rate for transmission;
> - $50/MWh energy cost;
> - 7.49 percent discount rate;
> - 40-year life;
> - $795,000 per mile to build the 230 kV alternatives;
> - $430,000 per mile for the 115 kV rebuild alternative;
> - additional cost adders for construction in wetland and forest areas;
> - $2 million for a 230 kV substation upgrade; and
> - $1 million for a 115 kV substation upgrade.
>
> Based upon experience in recent dockets and the Applicants' response to OES Information Request Nos. 51 to 57, the OES concludes that the above inputs are reasonable" (DOC Comments at 12).

Of course it is the objective of OTP and all parties to a CON proceeding that the best information may be ascertained and assessed based on what is reasonably known at the time of a CON application. However, because the projects under consideration are at such an early stage of development, estimates must be based on generally accepted per-mile construction costs and other planning estimate methodologies rather that detailed design and site condition-specific cost estimates. Also, it is reasonable to exclude from the estimates ancillary cost categories such as permitting, legal and other costs when it may not be reasonably possible to accurately estimate with specificity how such cost categories will impact the proposed project and the alternatives. In the B-GR CON Application, there is an explicit recognition that such costs will be incurred. There is just no quantification of such costs. As cited above, in the case of the B-GR CON estimates, the OES concluded that the inputs used for estimating project costs were reasonable. These Department Comments were adopted by the Commission as part of its Order approving the B-GR CON. It is not possible for OTP to now meet some higher expectation with respect to the granularity or specificity of the cost estimates used in that proceeding. Therefore, to apply such a higher expectation as an upper limitation on recovery is not a reasonable application of the planning estimates that were used in that proceeding.

In Xcel's 2012 TCRR Update proceeding, the question of whether Xcel's capital costs for the B-GR project should be capped arose.[6] An extensive discussion and analysis of the B-GR project CON estimates is included in Xcel Energy's Reply Comments in that Docket.[7] In summary, Xcel's explanation identified that CON planning estimates have not historically been applied as a cap in recovery proceedings, and Xcel further explained several factors that can affect project costs. For example:

- Many project costs are not reasonably capable of estimation at the time of the CON proceeding (when the project is in the early stages of development), such as costs specific to the eventual route, which has not been identified at the time of the CON application;
- Project costs can change from planning estimates for reasons that are not within the reasonable control of project management occur, which is not unusual for such projects (for example weather-related changes to construction conditions that can affect construction costs);

[6] IN THE MATTER OF XCEL'S PETITION FOR APPROVAL OF 2012 TRANSMISSION COST RECOVERY, PROJECT ELIGIBILITY, RATE FACTORS, AND 2011 TRUE-UP. Docket No. E002/M-12-50.
[7] Xcel's August 31, 2012 Reply Comments in DOCKET NO. E002/M-12-50, at 12-20.

- Escalation of costs is normal given the passage of time from CON application to actual construction;
- Design changes to associated facilities are possible, such as substation and underlying transmission facilities;

The Department filed Response Comments agreeing with some but not all of Xcel's positions.

An Order has not been issued in that Xcel proceeding, and it is OTP's understanding that all issues relating to recovery of Xcel's investment in the B-GR project were transitioned to Xcel's pending general rate case. OTP has not identified any testimony in Xcel's pending rate case where any party has disputed the prudence of the total costs expended on the B-GR project or recommended any disallowance of B-GR costs.

OTP generally agrees with Xcel's Reply Comments regarding the planning estimates cited in the CON for the B-GR project and their relation to costs actually incurred to construct the project. OTP also agrees with Xcel's arguments of why it would be inappropriate to cap the capital costs of the project for TCR recoveries to the CON planning estimates (see Xcel's Reply Comments in that Docket at pages 14-20). With respect to the specific costs incurred on the B-GR project, Table 1 in Xcel's Reply Comments is particularly helpful in reconciling the planning estimates that were included in the B-GR CON Application with the actual as-built costs of the project. Xcel's reconciliation and discussion explains that when reasonable adjustments are made to escalate the CON estimates (2007 $) to the period of construction (2012 $) and to take into account extraordinary and unforeseeable winter construction conditions and post permitting legal fees, the CON estimates are reconciled to $87.2 million of as-built costs. This reconciled amount does not include the Permitting, Right of Way and Legal fees that were explicitly referenced in the CON application but not quantified. When those costs are added, the CON estimate is reconciled to $110.9 million of actual as-built costs. The remaining additional costs identified in Xcel's Table 1 reconciliation (pipeline induction management costs, and associated facility costs) complete the reconciliation of the CON estimate to the actual as-built costs.

Additionally, OTP agrees with Xcel's Reply Comments that if the Commission were to establish a principle that OTP's TCRR recoveries should be limited to CON planning estimates, that ruling should apply on a going forward basis. Making such a determination on a going forward basis would give OTP adequate notice of this expectation and an opportunity to specifically quantify all anticipated costs and contingencies when preparing future CON applications.

In summary, the inclusion of these costs in the last annual Update to OTP's TCRR (Docket E017/M-10-1061) was appropriate and no adjustment to the inclusion of such costs should be made in this proceeding for several reasons.

First, making such adjustments to reduce the amount of capital costs would result in a reduction of the corresponding revenues, as described earlier. As was expressly recognized in the Commission's approval of OTP's last TCRR Update, and cited above, "*All Minnesota-jurisdictional costs of the [Bemidji-Grand Rapids and Fargo-Monticello Projects] will be included in the rider and all revenues attributable to the Minnesota-jurisdictional portions of the lines will be credited to ratepayers.*" This ruling recognized the substantial benefit for OTP's customers of including the B-GR investment in the TCRR. It also recognized that the costs included in the TCRR for the project must match the revenues that are attributable to those costs. While we do not expect it was the intention of the Department's recommendation to increase TCRR rates by excluding costs from the TCRR, that would be the practical effect of such an approach in this instance.

Secondly, it would not be appropriate to use CON planning estimates as a cap to recovery when OTP could not have reasonably known at the time it was preparing the CON application that the planning estimates would be applied in this way. As noted in the B-GR CON proceeding the cost estimating approach and inputs were reasonable for the evaluation of alternatives and the CON estimates can be reasonably reconciled to the actual as-built costs (as demonstrated in the Xcel Reply Comments Table 1). It would not be a reasonable application to the planning estimates cited in the CON application, to use them as an upper limitation on TCRR cost recovery. By their nature, such planning estimates must be made without specific information on routing, design or construction conditions. They also expressly do not include common ancillary permitting, legal and other costs. As Xcel explained in its TCRR proceeding, this is not how planning estimates have historically been used. For these reasons, the Commission should not establish a practice of capping costs at CON planning estimates.

C. BREAKDOWN OF AMOUNTS ATTRIBUTABLE TO CAPITALIZED INTERNAL COSTS, IMPACT OF EXCLUDING THOSE COSTS FROM THE TCRR AND EXPLANATION WHY SUCH COSTS SHOULD NOT BE EXCLUDED FROM TCRR

OTP does not disagree with the Department's statement that the issue of Internal Capitalized Costs has been raised in prior OTP Dockets[8] as well as the proceedings of other utilities. The fundamental concern raised by the Department for the disallowance of internal costs within Rider mechanisms is the concern that utilities may double recover these costs, claiming these costs are already included in base rates. This concern was raised in both of OTP's Dockets which the Department cites. However, the Commission did not specifically rule on this issue in those Dockets but instead, the issue was deferred from these Dockets to OTP's general rate case[9] at the time for determination as to the appropriate recovery of capitalized internal costs. OTP's response to these concerns is detailed in OTP's Reply Comments in the Renewable Rider proceeding (Docket No. E-017/M-09-1484 ("09-1484")), and those Reply Comments were later included in the rate case proceeding. OTP's Reply Comments from (09-1484) are included in Attachment A to these Reply Comments for reference.

In OTP's general rate case, OTP demonstrated for both the Renewable project costs and the costs associated with the Big Stone II Capital project, that under traditional rate making, internal costs attributable to long-term Construction Work In Progress (CWIP) projects were not being recovered in base rates due to the offsetting Allowance for Funds Used During Constructions (AFUDC) credit to the overall base rate revenue requirement. In the Administrative Law Judge's (ALJ) Findings of Fact, Conclusions and Recommendations Report issued February 14, 2011, the ALJ supported OTP's position and noted the following on pages 11 of that report:

"2. Inclusion of Capitalized Internal Costs

> ***47. The Company demonstrated that its capitalized internal costs were excluded from current rates and, therefore, not recovered. The Company explained that***

[8] OTP's 2010 Renewable Resource Cost Recovery Rider (Docket No. E-017/M-09-1484) and OTP's Big Stone II Deferred Accounting filing (Docket No. E-017/M-09-1484)
[9] OTP General Rate Case Docket No. E-017/GR-10-239

capitalized internal costs were accounted for in CWIP along with the other project costs, and that, in its last rate case, the CWIP costs were excluded from recovery through the use of the Allowance for Funds Used During Construction (AFUDC), which is a credit that increases the total available for return, reducing the revenue requirement. Thus, the long-term CWIP was excluded from the revenue requirements and rates.

48. If OTP is permitted to recover its costs in the Big Stone II project, there is no meaningful basis to distinguish the treatment of internal costs from external costs. There is no evidence demonstrating that the Company's own employees assigned to work on Big Stone II contributed less substantively than consultants or others the Company contracted with for the limited purpose of developing Big Stone II. Public policy is not advanced by encouraging utility companies to look outside their own personnel as they develop significant new projects."

The Commission agreed with the ALJ's recommendation and cited the following in Part D. Commission Action, Section 2 Big Stone II Costs are Recoverable, paragraph 5 found on pages 11-12 of the Commission's Order dated April 25, 2011:

The Commission likewise agrees with the Administrative Law Judge that there is no principled basis for disallowing recovery of internal costs not reflected in rates and that it is not in the public interest to discourage Otter Tail from making the best use of its internal resources and expertise.

OTP treats the internal costs capitalized to transmission projects no differently than the internal costs that were capitalized to renewable projects and to the Big Stone II project as cited above. These capitalized costs are not being recovered in base rates so the capitalization of internal costs to rider recoverable projects would not subject those costs to double recovery. Additionally, OTP has consistently included internal capitalized labor costs in its TCRR and the Commission has never previously denied recovery of these costs in prior OTP annual TCRR Petitions.

The public interest would not be served by excluding capitalized internal costs from TCRR recoveries. First, as noted in the above-quoted ALJ's recommendation and the Commission's Order from OTP's last rate case, it would not be in the public interest to discourage OTP from making the best use of its internal resources and expertise on transmission projects. To treat costs for internal resources differently from costs spent on external resources would serve as a disincentive from using those internal resources.

Secondly, as described earlier in these Reply Comments, if the amount of the capital costs included in the TCRR is reduced (by removing the capitalized internal labor costs) for the transmission projects that qualify for regional cost allocation, the corresponding MISO revenues will decline more than the corresponding MN TCRR revenue requirement, and the result will be higher rates, not lower rates. The specific calculations of how this occurs are explained below.

In OTP's response to the Department's Information request (MN-DOC-003), OTP indicated that approximately $1,762,985 of actual internal capitalized costs is included in the projects listed within the TCRR through April 2013. OTP calculated that the impact of removing actual costs incurred from project inception through April 2013, as well as projected costs through April of 2014, would be an increase in the revenue requirement of approximately $458,000. Table 2 below provides further breakdown of the revenue requirement calculations assuming internal costs are included (Column A), and assuming the internal costs are excluded (Column B). The overall change in revenue requirement is computed in the last column in the table. A more specific explanation of each line follows the table.

Table 2

		(A)	(B)	(B) - (A)
		With Internal Capitalized Costs	**Without Internal Capitalized Costs**	**Difference**
1	Revenue Requirements	5,680,520	5,519,050	(161,470)
2	MISO Expenses	4,412,583	4,412,583	0
3	MISO Revenues	(7,799,282)	(7,437,358)	361,924
4				
5	Carrying Charge	(11,725)	433	12,158
6	True-Up	(7,283)	237,815	245,098
7	Net Revenue Requirement	2,274,813	2,732,523	**457,710**

Column A of Line 1 in the table above reflects the revenue requirement based on 100% of OTP's investment in transmission projects included in the rider, including both internal and external costs. Column B of Line 1 reflects the revenue requirement computed on CWIP and/or completed project (in-service) amounts which exclude OTP's internal costs. The net impact is a ($161,470) reduction in revenue requirements due to the removal of the nearly $1.763 million of internal costs from the projects included in this TCRR.

Line 2 in the table above reflects MISO Schedule 26 and 26A expenses assessed to OTP for OTP's share of regionally allocated transmission costs assigned to OTP based on OTP's load within the MISO footprint. These expenses remain unchanged with regard to any impact of OTP including or excluding internal costs from the rider as ownership or investment is not a factor in this cost allocation through the MISO cost allocation process.

Line 3 in the table above reflects the MISO revenues attributable to OTP based on the level of investment OTP has made in transmission projects located within the MISO footprint. The MISO revenue credit in Line 3 Column A ($7,799,282) reflects the applicable MISO return based on 100% of OTP's investment in regional transmission projects. This revenue credit is calculated on investment amounts which include all costs (internal and external) for both the investment applicable to OTP's retail load as well as investment levels beyond the retail load. The MISO revenue credit shown on Line 3 Column B ($7,437,358) in the table above, reflects the reduced MISO revenue credit based on the exclusion of internal costs from CWIP or Rate Base amounts upon which the MISO Revenue Credit is calculated. The net impact is a reduction in the revenue credit (and increase in overall revenue requirement) of $361,924.

Line 5 reflects the carrying charge assessed to any over or under collection balance that exists within the TCRR. In the event that revenue collections exceed the revenue requirement, the carrying charge amount computed on the over-collection is recorded as a credit (Benefit to ratepayers) in the TCRR. In an under-collection situation, the carrying charge amount is added to the revenue requirement. Removing internal costs (historical and forecast) results in a slight increase in the overall revenue requirement of $12,158.

Line 6 reflects the balance of (over)under recovery within the tracker attributable to the prior collection period of the tracker. Removing the historic actual and forecast internal costs, (Revenue requirement impact quantified in line 1), removing the corresponding historic and projected revenue credits attributable to the excluded internal costs (revenue requirement impact quantified on line 3), results in an increase in revenue requirements of $245,098.

Line 7 of the table reflects the total net revenue requirement impact of including and excluding the internal costs from the TCRR. The sum of Lines 1 through 6 results in a $457,710 net increase in revenue requirement.

In summary, it would not serve the public interest to exclude capitalized internal costs from the TCRR. In the case of projects that qualify for regional cost allocation (which is the majority of the projects currently in OTP's TCRR), excluding such costs will increase rates as described above. In the case of other transmission projects, as the Commission recognized in OTPs last rate case there is no principled basis for disallowing recovery of internal costs, and it would not be in the public interest to discourage OTP from making the best use of its internal resources and expertise. For these reasons, adjustments to remove capitalized internal costs from the TCRR should not be made.

VI. COMPLIANCE REQUIREMENT FROM ORDER IN DOCKET NO. E017/M12-708: DEMONSTRATION THAT CARRYING CHARGES USED IN OTP'S RIDER PROVIDE FAIR AND EQUITABLE TREATMENT OF TRACKER ACCOUNT BALANCES

Due to the nature of how rate rider recovery mechanisms work, when revenue requirements are determined for each collection period, actual revenues collected will never match the approved revenue requirement for the collection period. To provide protection to both the ratepayers and OTP, a carrying charge is assessed on any over-collection or under-collection balance realized in the tracker. The carrying charge is based on OTP's overall rate of return approved in its most recent general rate case.

In OTP's most recent Renewable Energy Rider, Docket No. E017-M-12-708, PUC staff raised the question of whether it was appropriate to include a carrying charge on tracker balances. In the Commission's Order dated April 2, 2013, in that Docket, the Commission asked OTP to justify in its next rider filing the inclusion of any carrying charge imposed on the rider tracker account balances.

The Department noted in Section E on Page 9 of its Comments in this TCRR Docket, the tracker balance (True-up amount) showed an over-collection of approximately ($379k) for 2012 and a corresponding negative carrying charge of approximately ($27k) computed on that over-collection. Both the over-collection amount and the negative carrying charge amounts are <u>credited back</u> against the revenue requirement, <u>reducing the overall revenue requirement</u> for the next collection period proposed in the TCRR. This negative carrying charge is computed and credited to the customer based on OTP's current rate of return. In situations where an under-collection occurs, a carrying charge is assessed, increasing the revenue requirement for the subsequent collection period. A negative carrying charge protects the ratepayer from over-collection while a positive carrying charge protects OTP from under-collection.

OTP believes it is important to point out that the application of the carrying charge component provides both OTP and the ratepayers fair and equitable treatment of positive and negative tracker balances that are normal occurrences with rate rider mechanisms. OTP appreciates the Department's Comments finding that that 2012 true-up and carrying charge calculations are reasonable.

Based upon this discussion and consistent with the Department's recommendation in this matter, OTP requests that the Order in this matter include an indication that this explanation satisfies the requirement created by Ordering paragraph 4 of the April 2, 2013 Order in Docket No. E017-M-12-708.

VII. CONCLUSION

As is illustrated by Table 1 of these Reply Comments, OTP's capital investment in the projects included in the TCRR are providing a substantial benefit for OTP's customers. Those illustrated benefits are in addition to the reliability and market efficiency benefits that justify the transmission projects in the course of the regional planning process. Incentivizing these beneficial investments is at the heart of the legislation that authorizes TCRRs. As noted also, the TCRR allows for a retail rate mechanism that syncs up with MISO's FERC-authorized tariff mechanism. In OTP's last TCRR Update (Docket 10-1061), the Commission established a framework for which transmission cost recovery would, in the Commission's opinion, yield the greatest benefit to OTP ratepayers by requiring OTP to include all investment costs (and associated revenue credits) in the TCRR. The Department supported this position, and the Commission Order in 10-1061 noted that both the Department and OTP concurred that:

"…any rate making treatment adopted should be used consistently and equitably into the future and saw no reasonable possibility that this would not happen." [10]

OTP has submitted this TCRR Update filing in a manner that is consistent with the framework that was established in Docket 10-1061, including all Minnesota-jurisdictional costs attributable to the applicable transmission facilities, as well as all associated revenues attributable to the Minnesota-jurisdictional portions of the facilities.

OTP has also provided additional explanation why the adjustments recommended by the DOC should not be made to the recoveries occurring through OTP's TCRR. Capping these recoveries to some lower CON planning estimates is not warranted; excluding capitalized internal costs would not be appropriate or in the public interest.

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[10] Commission Order in Docket No. E-017/M-10-1061, Page 4. Section 2. The Department, Paragraph 3

OTP acknowledges that the Commission has the right to decide each case on the specific facts and the law. However, to implement the recommendations put forth by the Department to now disallow or cap certain costs from recovery in the TCRR, would run contrary to the Commission's prior rulings and the public interest and therefore such adjustments should not be made.

As noted above, OTP also agrees that the costs of the Sheyenne-Audubon project should be removed from the TCRR.

Finally, OTP requests that the Order in this matter include confirmation that the explanation included in these Reply Comments justifying its Rider tracker account carrying charge mechanism satisfies the requirement created by Ordering paragraph 4 of the April 2, 2013 Order in Docket No. E017-M-12-708.

Dated: June 27, 2013

Respectfully Submitted,

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Excerpt from OTP Reply Comments in OTP's Renewable Resource Cost Recovery Adjustment ("RRA") Factor Filing Docket No. E017/M-09-1484 March 29, 2010

I. OTP Response to OES Comments

The OES recommends the Commission approve OTP's 2010 Renewable Resource Cost Recovery Adjustment ("RRA") Factor with a modification to remove all capitalized internal costs. The OES believes that including these costs in the Rider rate may result in a double recovery of costs already being recovered in OTP's existing base rates. With respect to rate design, the OES recommends that the Rider should use a demand and energy charge for the Large General Service ("LGS") rate class customers and an energy charge for all other classes based on an 8 percent capacity allocation. In addition to these recommendations, the OES Comments also request that OTP provide information on how cost recovery for the Langdon, Ashtabula and Luverne wind projects (the "Projects") through the Renewable Rider might differ from cost recovery in base rates through OTP's soon to be filed general rate case, Docket No. E-017/GR-10-239 (the "2010 Rate Case")—the purpose of this request is to consider whether costs are appropriately reflected in each recovery mechanism and to consider whether one of the mechanisms is preferable from a customer perspective. The OES more specifically requested information on whether there is any difference in the treatment of the federal manufacturing production tax deduction or federal production tax credit under each approach.

A. Response to OES: Recovery of Capitalized Internal Costs Incurred During Development of the Rider Wind Projects.

Rider recovery of capitalized labor and internal costs associated with these Projects does not result in double recovery and, therefore, OTP would be denied all recovery if such costs were excluded from the Rider, as the OES recommends. The rationale for the OES's position is based on its belief that:

> "OTP is provided a representative amount of internal costs in a rate case through both: 1) the test-year amount of internal costs that are capitalized into CWIP, which is included in rate base and ultimately in the revenue requirement; and 2) the test-year amount of non-capitalized internal costs which is reflected as an expense on the income statement and included in the revenue requirement." (OES Comments at 9).

OTP addresses each argument below and explains why current rates do not include a representative amount of such costs. This explanation demonstrates why removing the capitalized labor and internal costs from the Rider would result in an inappropriate denial of recovery of these reasonably incurred costs.

(1) The capitalized costs in long-term CWIP were excluded from the revenue requirement in OTP's last rate case and, therefore, a representative amount of such costs is not being recovered in OTP's current rates.

The OES asked OTP to explain its earlier statements that the long-term CWIP had been excluded from current rates in its last rate case, given the OES's observation that a CWIP balance over $7 million was included as part of rate base.[1] While the OES is correct that $7 million of CWIP was reflected in the rate base balance, the CWIP was removed from rates as a result of the treatment of allowance for funds during construction (AFUDC). The AFUDC "offset" reduces the revenue requirement that would otherwise occur from including CWIP in rate base. In OTP's rate case income statement, a credit was made to increase net income (the

[1] The $7 million amount reflects both long-term and short-term CWIP.

total available for return) by the amount of the AFUDC associated with the long-term CWIP.[2] This credit increased the total available for return and reduced the revenue requirement. This crediting of AFUDC has the effect of excluding long-term CWIP from the revenue requirements and from rates. CWIP is capitalized along with AFUDC and recovered as part of plant investment (rate base) once the plant becomes operational. In the case of non-Rider investments, the recovery begins when rates are next set in a general rate case. In the case of Rider investments, the recovery begins when the Rider rate is set in the next annual RRA adjustment (like this one). In either case, the CWIP, including the labor and internal costs included in the CWIP, and the AFUDC that accrued during construction, becomes part of the rate base for which the utility is authorized to earn its allowed rate of return.

This approach of including AFUDC as an offset to the test year expenses is the generally accepted method used in Minnesota for excluding the long-term CWIP from the revenue requirement. Minnesota Law allows the Commission to depart from this approach in certain circumstances in order to allow a current return to be earned on the CWIP,[3] but OTP is not aware of many instances where the Commission has authorized such a departure.[4] OTP believes such a departure may be useful in certain circumstances, especially for very large project investments, but OTP did not seek such a departure in its last rate case with respect to its wind projects.

OTP agrees that if a departure from this method of using the AFUDC offset had been granted for a renewable project when establishing base rates in OTP's last rate case, then the

[2] *See* Exhibit ___PJB-1, Schedule 1, in Docket No. E017/GR-07-1178, line 23, which reflects that a $493,156 credit reflected in OTP's original filing; the actual amount of the credit to final rates is shown in the schedule from OTP's August 7, 2008 compliance filing in that docket, on the Revised Income Statement – Minnesota Jurisdiction Original Filing Compared to Commission's Decisions, line 21, where $488,851 in AFUDC is credited to reduce the revenue requirement.
[3] Minnesota Statutes, Section 216B.16, Subd. 6a.
[4] *See e.g. Minn. Power & Light v. Minn. Pub. Serv. Com'n*, 310 N.W.2d 686, 692 (Minn. 1981).

provision in the Renewable Rider Statute cited in the OES Comments would apply to the Rider recovery for that project, and earning on the CWIP through the Rider would not be appropriate. For convenience, the Rider Statute referenced by the OES is repeated here; it says that the Commission may approve a rate schedule that provides recovery of the costs of a renewable project and:

> (2) Provides a current return on construction work in progress (CWIP), provided the recovery of these costs from Minnesota ratepayers is not sought through some other mechanism. Minn. Stat. §216B.1645, Subd. 2a.

In OTP's case, however, as explained above, OTP has not sought authority to earn a current return on CWIP in its base rates or in some other mechanism. Therefore, excluding any costs from OTP's rider recovery would result in OTP being denied recovery of those costs altogether.

In summary, OTP has followed the accepted method of excluding the effects of the long-term CWIP from the revenue requirement by using the AFUDC offset and, therefore, there is no amount in OTP's current base rates that represents the capitalized internal labor and cost of the Rider wind projects. Therefore, if OTP is not allowed to recover those costs through its Rider, it will be inappropriately denied any recovery of those costs.

(2) The test-year amount of <u>expensed</u> labor and internal costs included in the revenue requirement in OTP's last rate case is not an appropriate representative amount of all labor and internal costs (both expensed and capitalized), such that recovery of <u>capitalized</u> labor and internal costs should be denied.

The OES asserts a second rational for denying OTP's recovery of its capitalized labor and internal costs for the wind projects: in effect, it takes the position that because OTP was allowed to include its test year expensed labor and internal costs in its rate case revenue requirement (and therefore in base rates), that any labor costs that are capitalized for construction projects in future years between rate cases must be disallowed as duplicative of the expenses built into rates. The OES's position runs contrary to fundamental rate making principles, and either ignores or confuses that in any year (including the test year) some portion of labor and internal costs is <u>expensed</u> and the remaining portion is <u>capitalized</u>. The OES's position implies that the portion of labor and internal costs that was expensed in the test year, will serve as a representative of both expensed AND capitalized labor and internal costs in future years. Therefore, the OES concludes the expensed portion of those costs included in the rate case revenue requirement is adequately representative of the capitalized labor and internal costs included in the Rider; and that recovery of those costs through the Rider should be disallowed as duplicative. Acceptance of this argument would allow a utility to recover only a portion of its labor and internal costs (the expensed portion). It would leave a utility without any recovery of its capitalized internal costs.

OTP included its test year expenses (including its expensed labor and internal costs) in its revenue requirement in its last rate case, but those expensed labor and internal costs by definition did not include OTP's capitalized labor and internal costs included in long-term CWIP (see the discussion of CWIP above). Therefore, to recover all its labor and internal costs, OTP must be allowed to recover both its expensed costs and its capitalized costs. By including the test year expensed costs in the base rate revenue requirement, OTP is receiving a representative amount of expensed costs in its current base rates, but it is not receiving a representative amount of its capitalized costs in current base rates. Those capitalized costs are made part of rate base as the projects for which they were incurred become operational. Thereafter, during the project's serviceable life, the utility recovers the project's costs by including in its rates the annual depreciation of its investment in the project and a return on the un-depreciated remainder of the investment. It is the depreciation and return on the net remaining investment that are reflected in the revenue requirement used to set rates—but they do not appear in rates until after the project becomes operational. If a utility were not allowed to put all its capitalized labor and internal costs into rate base, either through a rate case or through a special rate rider, it would be denied any recovery of those costs.

OTP provided information to the OES showing OTP's ratio of expensed internal labor costs to capitalized labor costs. That information demonstrates that OTP did not reduce its expensed labor costs between rate cases by diverting such costs to capital projects. Table 1 clearly shows that the portion of internal labor capitalized in the test year and subsequent years has been consistent.

Table 1

	2006 Test year	**2007**	**2008**	**2009**
Expense	84%	84%	84%	84%
Construction	16%	16%	16%	16%
Total	100%	100%	100%	100%

In addition, Table 2 shows the growth of actual labor expense that OTP has incurred in each year subsequent to its last rate case. This information shows that OTP has incurred increases to expensed costs in the years since its last rate case – costs that were not included in the current base rates that resulted from the last rate case. Consequently, the expensed internal costs included in the test year revenue requirement increased in subsequent years and current base rates do not recover all of those costs much less a portion of the capitalized expenses.

Table 2

	Labor Expense
2006 test year	$58,535,216
2007	$60,090,369
2008	$60,225,513
2009	$61,014,050

In summary, in OTP's last rate case, the long-term CWIP included in rate base was removed from rates by the inclusion of the AFUDC offset. Also, the test year revenue requirements included a representative amount of <u>expensed</u> labor and internal costs but not a representative amount of <u>capitalized</u> labor and internal costs. Those capitalized costs will be recovered through depreciation and a return on investment over the life of the project for which they have been incurred, either through the Rider or base rates as a result of OTP's 2010 Rate Case. Therefore, OTP is not including any of the Renewable Projects' capitalized labor and internal costs in current rates. Also, the amount of expensed costs used to set rates in OTP's last rate case was less than the amount of current expenses; and the proportion of internal labor being capitalized and expensed in OTP's last rate case and in subsequent years has been extremely consistent. For these reasons, the OES's recommendation to exclude capitalized labor and internal costs from Rider recoveries should be denied."

CERTIFICATE OF SERVICE

Re: **In the Matter of the Petition of Otter Tail Power Company for Approval of a Transmission Cost Recovery Rider Annual Adjustment**
Docket No. E017/M-13-103

I, Diane Merz, hereby certify that I have this day served a copy of the following on Dr. Burl W. Haar and Sharon Ferguson by e-filing, and to all other persons on the attached official service list by electronic service or by first class mail.

Otter Tail Power Company
Reply Comments

Dated this **27th** day of **June 2013**.

/s/ DIANE MERZ
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