12-2500-19336-2
E-017/GR-07-1178

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Otter Tail Corporation d/b/a/ Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota

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The above-entitled matter came on for evidentiary hearing before Administrative Law Judge Steve Mihalchick on March 17-21 and April 3-4, 2008, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota.

The parties to this proceeding are: Otter Tail Corporation d/b/a Otter Tail Power Company ("OTP" or the "Company"); the Minnesota Department of Commerce/Office of Energy Security (the "Department");[1] the Minnesota Office of Attorney General -- Residential Utilities Division ("OAG"); Enbridge Energy Limited Partnership and Enbridge Energy Company, Inc. ("Enbridge"); the Minnesota Chamber of Commerce (the "MCC"); AG Processing, Inc. ("AG Processing"); and Jonathan Drews who filed Direct Testimony, but has not otherwise participated in these proceedings. These intervenors, collectively, sponsored prefiled written testimony of 15 witnesses.

Appearances were made by the following: For OTP, Bruce Gerhardson, Associate General Counsel, Otter Tail Power Company, 215 South Cascade Street, Fergus Falls, Minnesota 56537, and Michael J. Bradley and Richard J. Johnson, Attorneys at Law, Moss & Barnett PA, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, Minnesota 55402. For the Department, Valerie Means and Karen Finstad Hammel, Assistant Attorneys General, 445 Minnesota Street, 1400 Bremer Tower, St. Paul, Minnesota 55101. For the OAG, Ronald M. Giteck, Assistant Attorney General, 445 Minnesota Street, 900 Bremer Tower, St. Paul, Minnesota 55101. For Enbridge, Robert S. Lee and Andrew P. Moratzka, Attorneys at Law, Mackall, Crounse & Moore, PLC, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, Minnesota 55402-2859. For the MCC and AG Processing, Richard Savelkoul, Attorney at Law, Felhaber, Larson, Fenlon & Vogt, P.A., 444 Cedar Street, Suite 2100, St. Paul, Minnesota 55101-2136

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Minnesota Public Utilities Commission (the "Commission") and the Office of Administrative Hearings, exceptions to this Report, if any, by any party adversely affected must be filed within 15 days of the mailing date hereof with the Executive Secretary, Minnesota Public Utilities Commission, Metro Square Building, Suite 350, 121 7th Place East, St. Paul, Minnesota 55101-2147. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions of Law and Order should be included, and copies thereof shall be served upon all parties. Oral argument before a majority of the Commission will be permitted to all parties

[1] The Department changed its structure to place responsibility for energy matters under the Office of Energy Security. This change came after the Department had filed Direct Testimony in this proceeding. Because the record generally refers to the Department, that identification has been retained for the purpose of these findings.

adversely affected by the Administrative Law Judge's recommendation who request such argument with their filed exceptions or reply. Exceptions should be e-filed with the Commission.

The Commission will make the final determination of the matter after the expiration of the period for filing exceptions as set forth above, or after oral argument, if such is requested and had in the matter.

Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that said recommendation has no legal effect unless expressly adopted by the Commission as its final order.

I. FINDINGS OF FACT.

A. Jurisdictional-Procedural Background.

1. On October 1, 2007, the Company filed its application, including its Direct Testimony, seeking a general revenue increase of $14,509,521.00 or 11.02 percent of total revenues (the "Application"), which was assigned Docket No. E-017/GR-07-1178 by the Commission. The Company used a historical test year ending December 31, 2006, with known and measurable changes, for this proceeding. On November 13, 2007, the Commission issued an Order Accepting Rate Case Filing and Suspending Rates ("Order Accepting Filing") and a Notice and Order for Hearing. In the Order Accepting Filing, the Commission found that the Company's Application was substantially complete as of October 1, 2007. On November 27, 2007, the Commission issued its Order Setting Interim Rates authorizing the Company, effective November 30, 2007, to collect $7,125,147 annually in interim rates.

2. OTP has, during the course of this proceeding, agreed to a number of adjustments, including the Department and OAG proposal to credit asset-based margins to the base rate revenue requirement instead of to the fuel revenue requirement. As a result, OTP is currently seeking an $8,260,330 increase in base rates, which is a 6.29 percent increase.

3. On January 31, 2008, the Department, OAG, the MCC, AG Processing and Enbridge filed Direct Testimony.

4. On February 29, 2008, the Company, the Department, and the MCC filed Rebuttal Testimony.

5. On March 10, 2008, Surrebuttal Testimony was filed by the Company, the Department, the OAG, the MCC, AG Processing and Enbridge.

B. Summary of Public Comments.

6. Public hearings were held on February 5, 2008, at the Bemidji City Hall in Bemidji (two members of the public spoke); February 6, 2008, 1:00 p.m., at the Morris City Hall in Morris (five members of the public spoke); February 6, 2008, 7:00 p.m., at the Fergus Falls City Council Chambers in Fergus Falls (six members of the public spoke); and February 7, 2008, at the Youngquist Auditorium of the University of Minnesota in Crookston (one member of the public spoke). A total of 14 members of the public participated in the public hearings by speaking. Comments included: praise for the Company's commitment to economic development in rural Minnesota communities; requests to the Commission for balance in considering the rate of return for investors with the increased costs for consumers; concern about the cost increase to the large general service customers; and the lack of support for wind generation. Commentators questioned

Otter Tail Corporation's purchase of unregulated businesses, how the fuel adjustment clause works, how energy costs are assigned to retail customers, and whether the rate case decision is made on the case as a whole, or on an issue by issue basis. Written public comments were accepted until March 3, 2008.

C. Description of the Company.

7. Otter Tail Corporation is a Minnesota corporation headquartered in Fergus Falls, Minnesota, doing business as Otter Tail Power Company. OTP began generating electricity in 1909. The Company now provides electricity to 423 communities and to unincorporated rural areas in western Minnesota, northeastern South Dakota, and the eastern two-thirds of North Dakota. As of year-end 2006, OTP was providing electricity and energy services to 129,035 customers: 60,472 in Minnesota, 56,894 in North Dakota, and 11,669 in South Dakota.

D. Burden of Proof.

8. Minn. Stat. § 216B.16, subd. 4, imposes on OTP the burden of showing "that the rate change is just and reasonable." Minn. Stat. § 216B.03 provides: "Every rate made, demanded or received by a public utility . . . shall be just and reasonable . . . . Any doubt as to reasonableness should be resolved in favor of the consumer."

9. The Minnesota Supreme Court described the Commission's role in determining just and reasonable rates in a rate proceeding as follows:

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (i.e., the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses.[2]

In that same case, the Minnesota Supreme Court also stated that:

> In evaluating the validity of a rate increase application, the Commission should apply the classic burden of proof analysis employed in civil cases in determining whether the utility has established the amount of a claimed cost as a judicial fact.[3]

10. In civil cases, the burden of proof has two separate meanings.

> 1. The duty of creating an affirmative belief on the part of the tribunal in the existence of the fact or facts in issue, or
>
> 2. The duty of introducing evidence at a particular stage of a trial -- of going forward with the evidence.[4]

[2] *ITMO the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota*, 416 N.W.2d 719, 722-723 (Minn. 1987).
[3] *Id*., 416 N.W.2d, at 722.

11. In this proceeding, the Administrative Law Judge will assess the evidence presented and make a recommendation to the Minnesota Public Utilities Commission ("Commission"). Whether OTP has met is burden of proof is ultimately for the Commission to decide, based on the record.

II. TRANSMISSION.

12. OTP moves electricity throughout its service area using transmission facilities. That electricity is provided to customers through lower voltage distribution facilities. The parties to this matter raised two related but separate issues concerning OTP's 41.6 kV and 69 kV facilities. The first issue is how the cost of those facilities should be allocated for jurisdiction cost of service study ("JCOSS") purposes. The second issue is a rate design issue -- should the existing "rolled-in rates" be retained or should there be a recognition of separate transmission and subtransmission functions.

A. The Jurisdictional Cost Allocation Issue.

13. As noted by the Commission in a prior order, "Rates for OTP have been established in the past as if the Company operates one system covering portions of Minnesota, North Dakota, and South Dakota."[5] To ensure fairness to ratepayers, "operating costs such as OTP's Minnesota personal property tax liability on generation have been allocated between the states .... "[6] OTP has used demand for its transmission jurisdictional allocator. Xcel Energy and Interstate Power & Light Company ("IP&L") also use demand for their transmission jurisdictional allocators.

14. Enbridge and MCC propose to allocate 115 and higher voltage costs based on demand, but the cost of 69 kV and 41.6 kV facilities based on mileage. The Enbridge/MCC adjustment would reduce the Minnesota revenue requirement by $3.04 million.[7]

15. The Department proposes to allocate the cost of 69 kV and higher voltage based on demand, but the 41.6 kV facilities based on mileage. The Department's adjustment would reduce the Minnesota revenue requirement by $1.73 million.[8]

16. OTP, Enbridge and the MCC agree that this issue should be determined based on whether the facilities are transmission or distribution under the guidelines established by the Commission.

17. The Department asserts that the transmission function of the 41.6 kV facilities is not relevant to how their costs are allocated, based on its assumption that such facilities provide only a local benefit and therefore should be allocated based on location.

18. The Commission addressed the asset separation issue in its *Boundary Order*, adopted in 2000.[9] The *Boundary Order* adopted Guidelines proposed by an industry group, and

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[4] Minnesota Practice, Vol. 11, Evidence § 301.05 at 13.00.

[5] *ITMO the Petition of Otter Tail Power Company to Implement Personal Property Tax Savings Credit*, PUC Docket No. E-017/M-02-515, at 5 (Commission Order Directing Refund and Rate Reduction, with Associated Compliance Filings issued September 6, 2002) (http://www.puc.state.mn.us/docs/orders/02-0126.pdf).

[6] *Id*.

[7] Ex. 69, Erickson Direct at 31. Mr. Erickson's Direct references $4.44 million, which includes a depreciation error of approximately $700,000. In addition, if costs are reallocated, it would also be necessary to reallocate revenues of approximately $700,000.

[8] Ex. 91, Johnson Surrebuttal at 10. Mr. Johnson identifies expenses of $1.27 million, to which would be added a rate base adjustment of $1.16 million, offset by the allocation of $700,000 in reallocated revenues. Ex. 116, Rogelstad Oral Supplement at 7; and Tr. V. 6 at 72.

directed that these Guidelines apply to: "competitive proceedings, cost separation dockets, rate cases, and valuations for asset transfers."[10] The Commission noted that "these issues are not of slight or transitory significance" and went on to state:

> Given the centrality of these issues, and the broad agreement among industry participants on the proposed guidelines for addressing these issues, the Commission will approve the proposed guidelines. The guidelines have the advantage of providing a uniform, state-wide framework for analyzing asset separation issues, while providing individualized application to various utilities. The guidelines shall be used wherever issues of identifying the assets involved in generation, transmission or distribution arise …. The Commission adopts the … guidelines for the purpose of determining the functional boundaries between the transmission and generation functions, and between the transmission and distribution functions. The Commission directs the parties to use the guidelines and appendices in all future proceedings involving unbundling and other relevant proceedings.[11]

19. The *Boundary Order* distinguished between generation, transmission, and distribution. There is no intermediary subtransmission category created in the *Boundary Order*.[12]

1. Determining Whether 41.6 kV And 69 kV Are Transmission Using The Boundary Order.

20. The *Boundary Order* sets out eight Minnesota Boundary Guidelines. OTP initially performed a system-wide analysis using the Boundary Guidelines and presented its results in Mr. Rogelstad's Rebuttal testimony.[13] That analysis focused on Guideline 1, which addresses transmission lines.

Minnesota Boundary Guideline 1

21. Guideline 1, as set out in the *Boundary Order*, states:

> Lines with voltage of more than 50 kV are considered transmission assets unless demonstrated to be distribution assets after application of the relevant factors. Lines with voltage of 50 kV or less are distribution assets unless demonstrated to be transmission assets after application of relevant factors. See Appendix A regarding "relevant factors."

22. Appendix A contains ten "relevant factors." The first Relevant Factor is: "How does the FERC 7-factor test apply and what is the result of its application."

23. <u>FERC FACTOR 1</u> states that local distribution facilities are normally in close proximity to retail customers. OTP's 41.6 kV and 69 kV facilities are not in close proximity to retail customers. The closest the transmission facilities come to retail customers is at the substations

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[9] *ITMO a Proceeding to Develop Statewide Jurisdictional Boundary Guidelines for Functionally Separating Interstate Transmission from Generation and Local Distribution Functions*, PUC Docket No. E-99/CI-99-1261 (Commission's Order Adopting Boundary Guidelines for Distinguishing Transmission From Generation and Distribution Assets issued July 26, 2000) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=767992) ("*Boundary Order*").
[10] *Id.* at 1 (emphasis added).
[11] *Boundary Order*, at 4.
[12] Tr. V. 6 at 121-122, Sherner.
[13] Ex. 18, Rogelstad Rebuttal at 14-25.

where the transmission delivers power to be stepped down for retail use.[14] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

24. FERC FACTOR 2 asks whether the facilities are primarily radial in nature. Facilities that are radial in nature do not have the ability to connect into or be looped to other transmission facilities and are more likely to be distribution. Radial lines can also be transmission if they perform a transmission function.[15] A radial line terminates to a substation where the energy is used and is not capable of operating in a looped fashion.[16] OTP's 41.6 kV and 69 kV transmission facilities have been planned and designed with looped capability and have the ability to transfer energy throughout the geographic region served by OTP and its interconnected neighbors.[17] OTP removed all radial lines (two percent of its lines were radial) and OTP's facilities do not terminate to a substation.[18]

25. MCC maintains that because OTP operates portions of its facilities normally open, all of the facilities are radial in nature.[19] Operating a line normally open means that somewhere in the transmission line a switch is opened so that power flows into the line from both ends rather than through the line. While open, the line separately serves the communities on each side of the open switch and cannot instantaneously support other transmission lines if there is a fault. By opening the lines, OTP improves reliability for communities served off the line. Mr. Schedin agreed that this practice enhances reliability for customers served by the line.[20]

26. OTP noted that it closes these normally open facilities on a daily basis, as maintenance is required and whenever a need exists to support other transmission demands during faults.[21] Mr. Sherner opined that the 41.6 kV facilities cannot be operated normally closed because the heavy loading on the overlay of high voltage transmission would result in 41.6 kV facilities overloads.[22] Mr. Rogelstad disagreed, noting that OTP operates the lines closed in its day-to-day operations,[23] and further stated that "OTP has installed sophisticated relaying systems that protect the lines to ensure that overloads will not occur."[24]

27. The configuration and operation of OTP's 41.6 kV and 69 kV facilities is looped, not radial in nature. Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

28. FERC FACTOR 3: Does power flow into the facilities and rarely, if ever, flow out? In distribution networks, the power is consumed and, therefore, power does not flow out. OTP has shown that it's 41.6 kV and 69 kV facilities were planned and designed to have power flow into, through, and out. Most of OTP's generation facilities are located in North and South Dakota, where power flows onto OTP's transmission facilities, including 41.6 kV and 69 kV facilities. That electricity flows out in Minnesota. More than 100 MWs of generation capacity is located in North and South Dakota that is used to serve OTP's Minnesota customers. This generating capacity is

[14] Ex. 18, Rogelstad Rebuttal at 16.
[15] *Id.* at 24.
[16] Ex. 18, Rogelstad Rebuttal Schedule 1.
[17] *Id.* at 16-17.
[18] *Id.* at 11 and 24; Ex. 118 at 4.
[19] Ex. 64, Schedin Surrebuttal at 25.
[20] Tr. V. 3 at 179, Schedin agrees that fewer customers would be affected if the line goes down.
[21] Ex. 18, Rogelstad Rebuttal at 11-12; Ex 116 at 7.
[22] Ex. 128, Sherner Surrebuttal at 14.
[23] Ex. 116, Rogelstad Hearing Statement at 7.
[24] *Id.*

directly interconnected to OTP's 41.6 kV transmission facilities. OTP has been working with MISO to process numerous additional third-party generator interconnection requests for use of its transmission system at the 41.6 kV voltage level.[25] Mr. Sherner agreed that 41.6 kV and 69 kV facilities that are connected to generation qualify as transmission.[26]

29. Mr. Schedin maintained that OTP's practice of operating portions of its lines normally open means that power normally flows in and rarely, if ever, flows out and is therefore distribution.[27] In response, OTP stated that all of OTP's lines are in a looped configuration,[28] most serve multiple loads,[29] many serve loads of other utilities,[30] (including GRE, which serves no distribution function), none serve a single load by terminating at a distribution substation,[31] and they are capable of supporting other transmission.[32] Additionally, OTP closes these lines on a daily basis.[33] OTP also operates approximately 20 percent (184.2 miles) of its higher voltage 115 kV lines normally. No one has maintained that OTP's 115 kV lines are distribution, not transmission.

30. Application of FERC Factor 3 to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

31. <u>FERC FACTOR 4</u>: When power enters the facilities is it ever reconsigned or transported to some other market? OTP jointly developed the integrated transmission system with its neighboring utilities, designing the system to transfer power for multiple utilities over the 41.6 kV and 69 kV facilities and to facilitate the Midcontinent Area Power Pool ("MAPP") and later the MISO Energy Market. A merchant wind generator has recently signed an interconnection agreement to interconnect with OTP's 41.6 kV facilities near Elbow Lake, Minnesota. The output of that third party's wind generation is not intended to serve OTP customers. That electricity is intended to be marketed to another utility or sold into the market.[34] Application of FERC factor 4 to OTP's 41.6 kV and 69 kV facilities supports a finding that these facilities perform a transmission function.

32. <u>FERC FACTOR 5</u>: Is the power that enters the facilities consumed in a comparatively restricted geographic area? OTP's 41.6 kV and 69 kV facilities are part of an integrated transmission network that transfers power across OTP's 50,000 square mile service territory. OTP inputs power on the transmission system, including the 41.6 kV and 69 kV facilities, in North and South Dakota, and pulls it out in Minnesota. The majority of these lines serve multiple communities,[35] and many serve loads of other utilities (including GRE, which serves no distribution function).[36] Most of the 41.6 kV and 69 kV line segments are long. The few segments that are short often serve other utility communities.[37] The treatment of these facilities under MISO's Tariff

[25] Ex. 18, Rogelstad Rebuttal at 17-19.
[26] Tr. V. 6 at 123.
[27] Ex. 64, Schedin Surrebuttal at 25.
[28] *Id.* at 11.
[29] Ex. 118, Attachment 1, Appendix A.
[30] *Id.*
[31] *Id.*
[32] Ex. 18, Rogelstad Rebuttal at 27-28.
[33] *Id.* at 11-12; Ex. 116 at 7.
[34] Ex. 18, Rogelstad Rebuttal at 19.
[35] Ex. 118, Attachment 1, Appendix A.
[36] *Id.*
[37] *Id.*

(discussed below) supports a finding that power transmitted over OTP's 41.6 kV and 69 kV facilities is not consumed in a restricted geographical area.[38]

33. Mr. Rogelstad provided a map of the Otter Tail service area with only OTP's 115 kV and above depicted. OTP noted that it also uses other utilities' transmission facilities. OTP's ability to use other utilities' facilities is conditioned on reciprocating by allowing those other utilities to use OTP's facilities, including OTP's 41.6 kV and 69 kV lines. OTP would be unable to provide power throughout its service territory without the use of approximately 3,900 miles of 41.6 kV and 200 miles of 69 kV lines and the reciprocal access those facilities provide to the transmission facilities of other utilities.[39] Application of FERC factor 5 to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

34. FERC FACTOR 6: Where are the meters that measure the flow into the local distribution system located? All of Otter Tail's transmission partners -- GRE, MCP, Missouri River Energy Services ("MRES"), etc. -- have metering on the distribution side of the distribution substation transformer. These substation transformers typically step down 41.6 kV to 12.5 kV with the meter on the 12.5 kV side of the transformer.[40] Application of FERC factor 6 to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

35. FERC FACTOR 7: Are these facilities of "reduced voltage." In reference to FERC Factor 7, FERC said, "The [FERC] has analyzed utilities' filings required by the [FERC]'s regulations. These filings are made on FERC Form No. 1. While there is no uniform breakpoint between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV."[41] OTP's 41.6 kV and 69 kV facilities are not of "reduced voltage" within the meaning of FERC factor 7.[42] Applying the FERC factors as required by the first Relevant Factor set out in Guideline 1 of the *Boundary Order*, supports a finding that OTP's 41.6 kV and 69 kV facilities should be classified as transmission.

36. The second "Relevant Factor" is whether the facility is installed only for the purpose of serving a particular "customer" (either generation or distribution). OTP's 41.6 kV and 69 kV facilities do not serve a particular customer.[43] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

37. The third "Relevant Factor" is: "Does the facility serve wholesale load or other grouped load (e.g., retail load pockets), either in looped or radial configuration?" OTP's 41.6 kV and 69 kV facilities serve wholesale load (i.e., municipal customers, neighboring generation and transmission coops (G&T Coops), and municipal power agencies (such as MPC, GRE, and MRES, etc.) as well as OTP retail customers. OTP noted that there are numerous transmission agreements between OTP and other utilities for the wholesale provision of electricity.[44] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

38. The fourth "Relevant Factor" is: "Was it designed to serve single phase load?" The OTP 41.6 kV and 69 kV facilities were designed to transmit three-phase power. OTP has identified

[38] Ex. 18, Rogelstad Rebuttal at 19.
[39] Tr. V. 6 at 89, Rogelstad.
[40] Ex. 18, Rogelstad Rebuttal at 20.
[41] *See* FERC Order No. 888, Appendix G, Footnote 100.
[42] Ex. 18, Rogelstad Rebuttal at 20.
[43] *Id*. at 21.
[44] Ex. 18, Rogelstad Rebuttal at 23.

four locations where a single phase load is connected to these facilities, but the total load connected in this fashion is less than 0.3% of OTP's total load.[45] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

39. The fifth "Relevant Factor" is: "Was it jointly planned to meet load-serving needs of more than one utility? Are there contractual relationships designating its use?" The vast majority of OTP's 41.6 kV and 69 kV facilities were jointly planned to meet the load serving needs of more than one utility. There are numerous contracts with neighboring utilities that govern the use of these jointly planned facilities. Most of these utilities are G&T Coops and municipal power agencies, which provide only generation and transmission services to their members.[46] The vast majority of OTP's transmission system is covered by one or more of these agreements.[47] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

40. The sixth "Relevant Factor" is: "What are the anticipated future uses of the facility? Is it planned to be looped?" OTP removed all radial lines and all of OTP's remaining lines are looped.[48] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

41. The seventh "Relevant Factor" is: "Does the facility interconnect two or more utilities?" OTP has numerous interconnections and Integrated Transmission Agreements (ITAs) . OTP has more than 200 interconnections with other utilities at just the 41.6 kV and 69 kV voltage levels.[49] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that these facilities perform a transmission function.

42. The eighth "Relevant factor" is: "Who operates the line? Who performs maintenance and emergency repair? How is it operated on a normal and contingent basis?" OTP provides its own operation and maintenance for all of the 41.6 kV and 69 kV facilities that it owns. For joint transmission facilities (where different utilities own individual segments of the line), each partner is responsible for the portion of each facility it owns.[50] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

43. The ninth "Relevant Factor" is: "What requirements does the facility meet under NESC design and maintenance codes?" The NESC is the National Electric Safety Code. Utilities must follow NESC codes as they design electrical facilities. OTP's 41.6 kV and 69 kV facilities meet NESC design and maintenance codes.[51] Application of this factor to OTP's 41.6 kV and 69 kV facilities supports a finding that the facilities perform a transmission function.

44. The tenth "Relevant Factor" is: "What is the dominant functionality of the facility?" Except for the few radial facilities that OTP removed, the 41.6 kV and 69 kV facilities were identified as used for the "transmission function 100 percent of the time."[52] This requires a determination based on the results of the other nine "Relevant Factors." Based on the evaluation of

[45] *Id*. at 22.
[46] *Id.*
[47] *Id.* at 22-23.
[48] *Id.* at 11 and 24; Ex. 118 at 4.
[49] *Id.* at 24.
[50] *Id.*
[51] *Id.* at 25.
[52] *Id.*

the facilities under the other nine Relevant Factors, the dominant functionality and, in fact, the only functionality of these facilities, is transmission.[53]

45. MCC asserted that OTP needed to perform its analysis of the 41.6 kV and 69 kV facilities using a segment-by-segment review, rather than the system level review that OTP conducted. In response, OTP performed a segment-by-segment analysis of the ten Relevant Factors. After conducting that additional study, OTP indicated that 117 miles of radial lines (constituting two percent of the total facility miles) would be removed from transmission treatment. In addition, OTP identified some minor changes to the classification given to some substation equipment. The collective revenue requirement affect of those changes was $7,200.[54]

46. OTP presented its segment-by-segment analysis shortly before the evidentiary hearings. Enbridge objected to the timing of the analysis and asserted that OTP had a duty to present the study with its initial filing. The analysis was admitted to the record and may be relied upon in this proceeding. The effect of admitting the analysis is to reclassify 117 miles of lines as distribution, reclassify some previously misidentified substations, and reduce OTP's revenue requirement by $7,200. Any other party that sought information on a segment-by-segment basis should have done so during discovery. There has been no showing of prejudice that would support excluding the analysis from the record of this proceeding.

Minnesota Boundary Guideline 2

47. This guideline is used to allocate substations (or portions of substations) to generation, transmission or distribution.[55] In the course of Otter Tail's review of its substation records, it identified some combination substations. The specific property records for these substations were reviewed. A list was prepared of specific facilities that should be reclassified as a function other than transmission.[56] Mr. Sherner identified two substations where he believed that OTP may have improperly allocated a transformer.[57] Mr. Sherner's criticism is irrelevant to the core issue of whether the 41.6 kV and 69 kV facilities serve a transmission function.

48. Minnesota Boundary Guideline 3 through Minnesota Boundary Guideline 8 were included in OTP's segment-by-segment analysis but are not relevant to the disputed issues in this proceeding.

49. In its segment-by-segment analysis, OTP determined that some facilities did not meet the requirements of the Minnesota Boundary Guidelines for transmission. These facilities served either a distribution function (*e.g.*, radial lines with no ability to loop), or a generation function. A summary of the results is presented in the following tables:

[53] *Id.*
[54] Exs. 116 and 118.
[55] Ex. 118, Attachment 1 at 3; and *Boundary Order*, Guideline 2.
[56] Exhibit 118, Appendix B.
[57] Tr. V. 6 at 111-114, Sherner.

Summary of 41.6 kV and 69 kV Lines

	Total Line Miles	Line Miles Determined to Transmission	Line Miles Determined to be Distribution
41.6 kV	3794	3682	112
69 kV	207	202	5

Summary of Substation Review

Transmission	Adjustment to Distribution	Adjustment to Generation	Adjusted Transmission
$54,429,051	$3,608,740	$1,505,020	$49,315,291

50. Making the foregoing changes to OTP's facility designations results in a reduction of OTP's revenue requirement by approximately $7,200.[58]

2. MISO and the Definition of Transmission.

51. Mr. Erickson asserted that when MISO took over operation of larger transmission facilities, only those facilities rated at 100 kV and higher would qualify as transmission facilities.[59] OTP Transmission service using facilities below 100 kV is governed by the MISO Tariff.[60] Nearly 50 percent of the branch transmission facilities included in MISO's Transmission Operator's rates were below 100 kV.[61] While MISO has affected how losses associated with facilities 100 kV and greater are recovered, the recovery of line losses for 41.6 kV and 69 kV facilities has not changed.[62] OTP maintained that MISO has limited its operations to larger voltage facilities because it would otherwise have been overwhelmed by the magnitude of the task of taking over the operation of all transmission.[63]

52. OTP's 41.6 kV facilities have been included in MISO planning where they are impacted by new generation projects.[64] MISO members' transmission rates are determined in MISO Tariff Attachment O. That portion of the MISO tariff does not distinguish between voltage levels.[65]

53. MISO is obligated by FERC Order 890 to include transmission facilities with voltage below 100 kV in future planning.[66] Mr. Sherner confirmed the accuracy of this.[67] Mr. Sherner went

[58] Tr. V. 6 at 69.
[59] Ex. 69, Erickson Direct, at 6/
[60] Ex. 18, Rogelstad Rebuttal at 7.
[61] *Id.* at 7.
[62] *Id.* at 9; and Tr. V. 6 at 52 and 123, Rogelstad.
[63] Ex. 18, Rogelstad Rebuttal at 5.
[64] Ex. 116 at 6.
[65] Tr. V. 6 at 121, Sherner.
[66] Ex. 18, Rogelstad Rebuttal at 7.
[67] Tr. V. 6 at 107, Sherner.

on to state that MISO is evaluating how to determine what qualifies as a transmission facility. Mr. Sherner's recommendation was for MISO to apply the *Boundary Order* and the *Mansfield* standards,[68] which he described as "useful standards."[69]

54. Every member of MISO, except Minnesota Power, includes lower voltage transmission in their FERC Form 1 reports.[70] FERC Form 1 (RUS Form 12 for GRE) annual reports provide the information for MISO Attachment O rates.[71] The following table is based on those reports, which were attached to Ex. 116:

Utility	Percentage of Transmission above 115 kV	Predominate voltage below 115 kV and percentage of total transmission
OTP	23 %	41.6 kV is 73%
GRE	33%	69 kV is 56.6%
IP&L	35%	69 kV is 31%, 34.5 kV is 34% (located in Iowa)[72]
MDU	41%	41.6 kV is 35%
NSP WI	57%	69 kV is 42%
NSP MN	60%	69 kV is 38%

55. OTP has demonstrated that, excluding lines owned by Minnesota Power, at least 40% of the transmission miles for every Minnesota MISO member are provided by facilities of 69 kV or lower.

56. The creation of MISO has not changed the standards used to classify facilities as being used for transmission or distribution. Classification of facilities as transmission or distribution is a duty of the Commission, not MISO. The standards set out in the Commission's *Boundary Order* are the criteria for that classification. Applying those standards supports OTP's position, as adjusted through its segment-by-segment analysis.

3. Shield Wires.

57. Mr. Erickson and Mr. Schedin concluded that because a portion of OTP's 41.6 kV and 69 kV lines do not have shield wires, none of OTP's 41.6 kV and 69 kV facilities qualified as

[68] *Mansfield Municipal Electric Department and North Attleborough Electric Department v. New England Power Company*, 97 FERC 61,134 (2001).
[69] Tr. V. 6 at 107 and 135.
[70] Ex. 116.
[71] Tr. V. 4 at 61.
[72] The Iowa Utilities Board determined that the 34.5 kV lines are properly characterized as transmission by applying the FERC 7-Factor Test. *Interstate Power and Light Co. and ITC Midwest LLC,* IUB Docket No. SPU-07-11, ORDER TERMINATING DOCKET AND RECOMMENDING DELINEATION OF TRANSMISSION AND LOCAL DISTRIBUTION FACILITIES, at 74-75 (September 20, 2007).

transmission facilities. Mr. Sherner did not include this argument in his testimony. OTP noted that the argument was no longer being pursued by Enbridge or the MCC. Because the argument appeared in testimony, it will be addressed here.

58. The use of shield wires is not a criterion in either the Commission's Boundary Order or the FERC 7-Factor Test. The purpose of shield wires is to provide protection from lightning strikes. Shield wires do not affect capacity.[73] There was some suggestion that shield wires could be a requirement for service quality purposes.[74] That would be a cost/benefit issue that is not determinative of the function of the facility.

59. OTP has installed alternative methods protect against lightning strikes on those facilities that do not rely on shield wires. OTP noted out that 23 percent of its 115 kV lines do not have shield wires.[75] There is no dispute that the 115 kV lines are properly characterized as transmission.

60. The presence or absence of shield wires does not have any impact on the characterization of lines as transmission or distribution.

B. Demand-Based Transmission Allocation.

61. OTP's practice has been to allocate transmission based on demand. Enbridge and the MCC agreed that transmission should be allocated based on demand. Characterizing 41.6 kV and 69 kV facilities as distribution, not transmission, Enbridge and MCC advocate allocating those facilities based on mileage, not demand. The Department maintains that using different allocation methods for transmission facilities based on voltage is a reasonable approach. The Department proposes allocating 41.6 kV facilities based on mileage, analogizing the different voltage facilities to the difference between highways and byways.

62. OTP noted that Xcel Energy and IP&L both allocate all of their transmission in their jurisdictional cost of service studies ("JCOSS") based on demand.[76] This practice is supported as reasonable because demand drives the cost of transmission. Each of these utilities treats lower voltage facilities as transmission.[77] OTP noted that Xcel Energy has two transmission rates, one for voltage below 69 kV and another for voltage at 69 kV or higher. While Xcel Energy has different rates for these two transmission service levels, it uses the same jurisdictional demand allocator for all transmission.[78]

63. Transmission is allocated based on demand because, as load (demand) increases, so does the need to use higher voltage facilities.[79] The role of load in determining the voltage levels was explained by Mr. Rogelstad as follows:

> I think it all comes down to load density. The facilities that we've had in place, if you go back to 1986, were adequate to meet the load requirements of the transmission system back then. And in some cases we've had to upgrade those facilities, and I've

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[73] Tr. V. 4 at 49, Erickson.
[74] Tr. V. 7 at 176-177.
[75] Ex. 18, Rogelstad Rebuttal at 13.
[76] Tr. V. 2 at 32; IP&L Docket No. E001/GR-05-748, Initial Filing Volume IV, Information Requirements, Exhibit __ (CAH-1), Schedule B-5, page 1 of 2, and Schedule G-1, indicating that System Coincident Peak was used, the same method used by OTP.
[77] *See* Finding 54, above.
[78] Tr. V. 2 at 32;
[79] Ex. 116, Rogelstad Hearing Statement at 2.

provided a couple of examples in my testimony, where we brought them from a 41.6 kV to 115 because of a load increase or generation added that required a larger capability line. And therefore, because of the relatively low load density and vastness of our system, the 41.6 kV system is adequate.[80]

64. Lower voltage facilities cost less to install and operate.[81] Minnesota has a higher load than do North Dakota and South Dakota. Reflecting that, Minnesota requires more higher voltage/higher-cost transmission facilities to serve its load than do North Dakota and South Dakota. Using demand to allocate those costs assigns costs on a cost causative basis. Conversely, North Dakota and South Dakota have a lower load than Minnesota. Reflecting that, North Dakota and South Dakota require lower voltage/lower-cost facilities to serve their loads. Using demand to allocate those costs properly allocates more of the cost savings from those lower-cost facilities to North Dakota and South Dakota.[82]

65. Minnesota's demand in OTP's service area is roughly equal to the demand of OTP's service area in North Dakota and South Dakota combined.[83] Relying on demand as the allocator, Minnesota should pay approximately 50% of the cost of generation and transmission. If OTP's 41.6 kV facilities were allocated based on mileage, North Dakota and South Dakota would pay 68% of the cost of those facilities while still paying 50% of the cost of higher voltage facilities.[84]

66. No evidence was put forward to support using mileage or location as a cost-causative method of recovering a cost that is demand driven.

67. The Department asserted that even if the 41.6 kV and 69 kV facilities are providing a transmission function, there is no requirement that lower voltage transmission be allocated based on demand. The Department maintained that mileage is a more cost causative approach.[85] The Department did not offer an engineering or operational basis for distinguishing between higher and lower voltage facilities. The Department relied on Mr. Schedin's assertion that these lines offer no benefit outside of where they are located.[86] Based on this, it was argued that high voltage could be treated like a highway, while lower voltage could be treated like a byway. No example was provided of how such a distinction is currently being employed with respect to transmission.[87] MISO Attachment O does not distinguish between voltage levels in terms of rates.

68. OTP maintained that Minnesota ratepayers benefit from the 41.6 kV lines throughout the OTP system. OTP asserted that without those lines OTP would not have access to other utilities' transmission facilities granted though ICAs. Absent that access, OTP would not be able to deliver generation, most of which is located in the Dakotas, to Minnesota retail customers.[88]

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[80] Tr. V. 6 at 87-88, Rogelstad.
[81] Tr. V. 6 at 119, Sherner.
[82] Tr. V. 6 at 87-88, Rogelstad.
[83] Tr. V. 4 at 112-113, Mr. Schedin testified that the D1 factor for Minnesota is comparable to the combined North Dakota and South Dakota D1 factor. This indicates that the demand in Minnesota is comparable to the demand and for North Dakota and South Dakota combined.
[84] Ex. 89, Johnson Direct at 14.
[85] Ex. 91, Johnson Surrebuttal at 8.
[86] Ex. 90, Johnson Rebuttal at 4.
[87] Tr. V. 5 at 23-24, Johnson.
[88] Ex. 116, Rogelstad Evidentiary Hearing Statement and the attached map; Tr. V. 6 at 89, Rogelstad.

69. OTP noted that Minnesota ratepayers benefit from the more than 100 MW of generation in North Dakota and South Dakota. This generation is directly connected to 41.6 kV lines, thereby providing a direct benefit from those facilities to Minnesota.[89]

70. OTP maintained that it has avoided incurring the significant costs of installing a new 115 kV line by instead installing a new 230/41.6 kV substation. As a consequence, the existing 41.6 kV facilities saved $14 million in investment to the benefit of the ratepayers.[90]

71. OTP has demonstrated that its 41.6 kV facilities are an integrated part of the transmission network, those facilities provide more than a localized benefit, and that the use of demand to allocate those facilities results in reasonable rates.

C. The Proposed Jurisdictional Allocation Changes Jeopardize OTP's Ability to Recover Its Cost of Service.

72. OTP noted that each of the Commissions in North Dakota, South Dakota and Minnesota have approved identical jurisdictional allocators. This allows OTP to recover its cost of providing service without risk of over- or under-recovering its revenue requirement. Several parties have proposed three significant allocation changes (subtransmission, E8760, and breakeven methodology) which would increase the collective cost of service in North Dakota and South Dakota by $6.3 million.[91] Such reductions in revenues and earnings would reduce OTP's Minnesota ROE by 350 basis points, from the 11.25 percent to 7.75 percent, which is far below the ROEs of comparable companies.[92]

73. OTP has shown that recovery of these cost shifts in North Dakota or South Dakota is unlikely in the near term. In North Dakota, 41.6 kV or higher facilities are statutorily classified as transmission facilities pursuant to NDCC § 49-21.1-01. Recovery of such cost shifts in North Dakota would require amendment of that statute.

74. In prior orders, the Commission has expressly recognized the importance of using consistent jurisdictional allocation processes between the jurisdictions in which a multi-state utility does business.[93] The Commission's decision rejecting a jurisdictional allocation change in Minnesota without a similar change in the other jurisdictions was upheld on appeal.[94]

75. The Commission has consistently adhered to its responsibility to set rates in the public interest, which requires careful balancing of the interests of both the utility and its ratepayers. The public interest is furthered when issues are resolved within the bounds of accepted regulatory practice.[95] The public interest is not served if reasonable consistency cannot be obtained among jurisdictions.

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[89] Ex. 18, Rogelstad Rebuttal at 17-18.
[90] Ex. 116, Rogelstad Evidentiary Hearing Statement at 2.
[91] Ex. 15, Moug Rebuttal at 5.
[92] Ex. 17, Hevert Rebuttal at 70.
[93] *Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers Within the State of Minnesota*, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER, Docket No. E-002/GR-85-558 at 23 (June 2, 1986) and *In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates,* ORDER AFTER RECONSIDERATION (October 20, 1988)..
[94] *ITMO of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates,* 416 N.W.2d 719, 728 (Minn. 1987).
[95] *In the Matter of the Application of Interstate Power for Authority to Change its Rates for Natural Gas Service in the State of Minnesota*, Docket No. G001/GR-90-700.

D. Should Transmission Be Functionalized Into High and Low Voltage.

76. Enbridge and MCC proposed that two separate rate classes, transmission and subtransmission, be established. This would be a change from the existing approach, called a "rolled-in" rate, that does not distinguish between high and low voltage. The proposed change would be based on functionalizing costs in a manner that allocates none of the lower voltage transmission costs to Enbridge.

77. This identical issue was addressed by FERC regarding OTP in 1980. As a result of being required by the U.S. Supreme Court to provide transmission services to the municipality of Elbow Lake, Minnesota,[96] the issue arose whether Elbow Lake should only pay for the lower cost 41.6 kV facilities used to serve it, or whether it should be required to pay a rolled-in rate that included the cost of higher voltage facilities. FERC ruled that OTP operated an integrated system, and consequently a rolled-in rate should apply.[97]

78. Mr. Sherner asserted that if FERC were to address this issue fresh today it would apply the FERC 7-factors, as reflected in *Mansfield.*[98] In *Mansfield*, FERC accepted an Administrative Law Judge recommendation, which stated in part: "Commission policy is that transmission rates should be assessed on a rolled-in basis absent a showing that **particular** facilities are not integrated with the transmission system as a whole." (Emphasis added.) The analysis conducted by OTP applied the FERC 7-factors, and suggests that FERC would again apply a rolled-in rate.

79. Mr. Sherner testified that Enbridge should not contribute to the cost of lower voltage facilities unless "OTP can successfully demonstrate they provide meaningful ongoing or emergency support to their pumping stations."[99] Mr. Rogelstad and OTP information responses demonstrated that the lower voltage 41.6 kV and 69 kV facilities in the Bemidji area are used during outages of higher voltage transmission, in order to maintain adequate service quality to the area.[100] Mr. Sherner agreed that OTP is able, through use of lower voltage facilities, to improve line flow by 10% to two of Enbridge's locations, by 25% to another Enbridge location and by 50% to a third Enbridge location. OTP was able to restore voltage from .902 (90% of normal) to .0967 (97% of normal) in one of these locations using lower voltage facilities.[101] This ability to restore voltage to 97% is necessary to meet North American Electric Reliability Association (NERC) certification.

80. Absent the ability to rely on lower voltage transmission facilities to meet NERC standards, substantial and costly 115 kV facility additions would be required and these costs would be passed on to Minnesota ratepayers. Under Enbridge's cost allocation argument, Enbridge would need to pay proportionately for the additional facilities.

81. OTP noted that it has transmission customers that connect to a substation connected directly to 115 kV lines. OTP also has transmission customers that connect to substations that are connected directly to 41.6 kV and 69 kV transmission lines. The lower voltage facilities are often "down stream" from higher voltage facilities located "upstream." Under the approach advanced by Enbridge and MCC, transmission customers connected to lower voltage facilities would be

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[96] *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973)
[97] Ex. 18, Rogelstad Rebuttal at 25-26; *Otter Tail Power Company*, 12 FERC ¶ 61,169, at 61,420 (1980).
[98] Tr. V. 6 at 129, Sherner.
[99] Ex. 128, Sherner Surrebuttal at 16.
[100] Ex. 18, Rogelstad Rebuttal at 27-28.
[101] Tr. V. 6 at 129, 133, Sherner.

allocated costs for all transmission facilities.[102] In contrast, transmission customers connected to a 115 kV line would not be allocated any costs of the "downstream" 41.6 kV and 69 kV facilities because they did not use the downstream facilities.[103]

82. Enbridge is located in the Bemidji area, which has a high load density when compared to the rest of OTP's service area. OTP maintained that this high load density, not the demand from Enbridge, created the need to install a 115 kV line to serve the area.[104] Absent the surrounding load, Enbridge could have been served off of a lower voltage facility.[105] OTP maintains that Enbridge's upstream location is a matter of geographic coincidence, not a demonstration of cost causation.

83. OTP maintained that, following the approach of Enbridge and MCC, the retail customers located in Bemidji (who are served by a substation connected to a 115 kV line) should pay lower rates than retail customers located in Kalstad and Plummer (which are served by a substation that is connected to a 41.6 kV line that is downstream from the 115 kV line that serves Bemidji).[106] In other words Kalstad and Plummer customers use both a 41.6 kV line and a 115 kV line while Bemidji customers only use a 115 kV line to be served. OTP noted that the Commission has not previously established retail rates based on an "upstream/downstream" basis.

84. OTP also noted that Enbridge, as a contributing cause to the need for higher cost 115 kV transmission, could be allocated a greater portion of those costs. OTP noted that a synchronous condenser was installed in the Solway peaking plant to provide needed voltage support to the Bemidji area.[107] If location-based pricing is used, OTP maintains that some additional portion of those higher costs should also be borne customers in the Bemidji area, including Enbridge. North Dakota and South Dakota customers are located much closer to OTP's primary generation resources. Using the upstream pricing theory, customers in those states are upstream of Minnesota and those customers should be allocated less cost than Minnesota customers. OTP noted that it has plans to install an additional $67 million in new high voltage transmission in the region serving Enbridge. If locational pricing were to be instituted, Enbridge would be required to pay a greater portion of those costs.

85. Enbridge is the only transmission customer of OTP which has its own step down transformer. Enbridge receives a lower rate due to this factor and benefits from other load-based considerations. For OTP's particular LGS rate, Enbridge is the only customer served. OTP has no customer that receives a lower (non-time of day) rate.[108] The terms under which Enbridge receives service were negotiated. A change in cost allocation would not, by itself, result in a lower rate for Enbridge.

86. All of OTP's Minnesota customers (including Enbridge) benefit from the use of rolled-in rates to establish pricing. There has been no showing that location should be used to set rates.

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[102] Tr. V. 3 at 185, Schedin; Tr. V. 4 at 56, and 60, Erickson.
[103] *Id.*
[104] *See* Tr. V. 4 at 36, Erickson.
[105] Enbridge steps down the transmission to 4 kV. The surrounding area load requires use of a 115 kV line, not Enbridge.
[106] Ex. 129 is a drawing of one of the 115 kV line in the Bemidji area and lists the facilities used to serve the different customer and municipal customer groups.
[107] Tr. V. 6 at 146-147, Sherner.
[108] Tr. V. 4 at 28, 30, 33-35, Erickson.

E. Conclusion.

87. OTP's 69 kV and 41.6 kV facilities meet the Commission's standards for allocation as transmission. Allocating the costs of those facilities by demand is appropriate in order to recognize the relationship between demand and the costs required to provide the necessary transmission voltage. The use of rolled in rates for transmission customers is readily applied and results in reasonable rates for OTP's customers.

III. RATE OF RETURN.

A. Summary.

88. The rate of return (ROR) is determined by the weighted average cost of the various sources of capital used by a company. Capital structure generally refers to the mix of long- and short-term debt, preferred stock, and common equity. Because the various types of capital have different cost rates, each component is weighted by its relative proportion in the overall mix of capital to determine the overall cost of capital. As a result, the overall ROR is dependent on the costs and types of capital used by the company.[109]

B. Capital Structure.

89. For the Commission to carry out its statutory responsibility to set rates that are just and reasonable, a balancing of consumer and utility interests must be performed. A reasonable rate enables an investor-owned utility to recover its operating expenses, depreciation, and taxes, as well as compete for funds in capital markets. Allowing a fair and reasonable return upon the utility's investment in property used to provide the utility service is a factor in setting just and reasonable rates. This return on investment in property is more commonly referred to as return on equity (ROE).[110]

90. OTP has no existence separate from Otter Tail Corporation, thus OTP has no publicly traded common stock. Since ROE is a market-based concept, it is necessary to establish the ROE figure by other means. The Commission has historically relied upon the Discounted Cash Flow (DCF) analysis to derive ROE for rate cases. This is the most widely accepted model and one that has been used consistently as a starting point for establishing the cost of equity in public utility cases before the Commission.[111]

91. OTP conducted a comparison of its proposed capital structure with comparable companies' utility operating subsidiaries. This comparison was conducted with utility holding company data because the utility operating subsidiaries are not separately traded entities and, thus, lack direct market data. OTP maintained that its capital structure should be evaluated by comparison to the capital structures of the utility operating companies owned by the utility holding companies within the comparable groups.[112]

92. The Department objected to OTP's proposed capital structure as having too high a common equity figure. The OAG proposed an even lower equity figure, based on trends in the

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[109] *See* Ex. 130 (Kaml Direct) at 11.
[110] *ITMO the Application of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota*, DOCKET NO. G-002/GR-06-1429, at 28 (Commission Findings of Fact, Conclusions of Law, and Order issued September 10, 2007)(*NSP Gas Rate 2007 Order*) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=4768622).
[111] *NSP Gas Rate 2007 Order*, at 28.
[112] Ex. 17, Hevert Rebuttal at 63.

U.S. capital markets, particularly the current low cost of equity.[113] The parties' competing proposed capital structures are as follows:

	OTP Proposal	Department Proposal	OAG Proposal
Short Term Debt	4.10%	4.10%	4.10%
Long Term Debt	39.40%	42.30%	44.75%
Preferred Stock	3.60%	3.60%	3.60%
Common Equity	52.9%	50.00%	47.55%
Total	100.0%	100.0%	100.0%

93. The effect of the Department and OAG proposals is to move more of the accounting structure into lower cost categories, thereby reducing the overall revenue required to meet the ROE figure. OAG further recommended that OTP be made a separate subsidiary of a newly formed holding company under Otter Tail Corporation.[114]

94. OTP maintained that its proposed capital structure is supported by OTP's comparatively low cost of long term debt (LTD), which is 6.32%. This figure was contrasted with the LTD cost of 6.59% experienced by Otter Tail Corporation.[115] OTP maintained that its cost of LTD has been consistently lower than that of other Minnesota utilities, as set forth below:[116]

[113] Ex. 130, Kaml Direct at 4-9.
[114] OAG Brief, at 1.
[115] Ex. 13, Moug Direct at 4.
[116] *Id.* at 5.

	2003	2004	2005	2006
Minnesota Power	6.83%	6.60%	6.03%	5.87%
OTP	**6.31%**	**6.30%**	**6.36%**	**6.33%**
Interstate	7.09%	6.88%	6.81%	6.61%
Xcel-MN	7.88%	7.40%	6.95%	6.79%
Xcel-ND	7.87%	7.32%	6.97%	6.83%
MDU-ND	8.78%	8.62%	8.71%	7.98%
Source: Annual state regulatory reports				

95. The cost of LTD to OTP is not determinative of the appropriate capital structure. The capital structure must reflect the appropriate economic structure of the utility operations for which ROE is being calculated. The Department has demonstrated that its proposed capital structure is appropriate for the ROE calculation.

96. Based on its proposed capital structure, OTP recommended an overall rate of return ("ROR") of 8.89%, including a ROE of 11.25%, as follows:[117]

	Percent of Total	Cost	Weighted Cost
Short Term Debt	4.1%	6.52%	0.27%
Long Term Debt	39.4%	6.32%	2.49%
Preferred Stock	3.6%	4.75%	0.17%
Common Equity	52.9%	11.25%	5.96%
Total	100.0%		8.89%

There was no dispute regarding: (1) the costs of LTD, Short Term Debt ("STD"), or Preferred Stock; or (2) portions of the capital structure for STD or Preferred Stock.

97. The Department, through Dr. Eilon Amit, and OAG, through Mr. Clark Kaml, also made recommendations in regards to both the Company's ROR and ROE. The final recommendations of the parties on the substantive issues are as follows:

	ROE	Common	ROR

[117] Ex. 15, Moug Rebuttal Schedule 1.

		Equity Ratio	
Company	11.25%	52.9%	8.89%
Department	10.91%	50.0%	8.57%
OAG	9.69%	47.55%	7.97%

C. Standards for Determination of the ROE.

98. The basic standards for the determination of ROE are set forth in *Hope*[118] and *Bluefield*[119] and in Minn. Stat. § 216B.16. *Hope* and *Bluefield* establish standards that require a return that is: (1) consistent with other businesses having similar or comparable risks; and (2) adequate to support credit quality and access to capital, while maintaining financial integrity. Minn. Stat. § 216B.16 refers to "the need of the public utility for revenue sufficient to enable it … to earn a fair and reasonable return upon [its] investment … ."

99. The Commission's order should provide the Company with the opportunity to earn a ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure the financial soundness of the Company's operations; and (3) commensurate with returns on investments in utilities of comparable risks.

D. The Discounted Cash Flow ("DCF") Model.

100. The Discounted Cash Flow ("DCF") model is based on the theory that a stock's price represents the present value of all future expected cash flows. The DCF model is widely used to determine ROEs for utilities.[120] The DCF model expresses the ROE as the sum of the expected dividend yield and long-term growth rate.[121]

101. The most common form of the DCF model is the "Constant Growth" form. Under the Constant Growth DCF model, the price of a stock is a function of the collective ROE required by investors, which is determined as the sum of dividend yield and growth.[122]

102. Multi-period DCF models have also been proposed for use in utility proceedings to calculate the cost of equity. The difference between the Constant Growth and Multi-period DCF models are in the assumptions for rates of growth to be experienced throughout the period studied. Multi-period DCF models are reasonable means of calculating the cost of equity, but they can be more sensitive to the inputs and assumptions used by the analyst.[123] The Commission has

[118] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) ("*Hope*").
[119] *Bluefield Waterworks and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").
[120] Ex. 16, Hevert Direct at 15.
[121] *Id.* at 13-14.
[122] In its most common, Constant Growth form, DCF model is expressed as follows:

$$k = \frac{D(1+g)}{P} + g \quad [1]$$

where "k" equals the required return, "D" is the current dividend, "g" is the expected growth rate, and "P" represents the subject company's stock price. Ex. 16, Hevert Direct at 14.
[123] Ex. 17, Hevert Rebuttal at 17.

consistently relied on the Constant Growth DCF model and has rejected the suggestion to rely solely on multi-period DCF models.[124]

103. Dr. Amit analyzed OTP's reasonable costs of equity using both a Constant Growth DCF and a multi-period DCF analysis to support the Department's position on ROE. The Two Growth DCF essentially requires the same variables as the Constant Growth DCF, except there are two growth rates, one for the first period, and a second rate for long-term growth rate. Dr. Amit used a "Two Growth DCF" in a multi-stage DCF model for three of the companies in his comparable group.[125]

104. In arriving at an ROE, Mr. Hevert used both a Constant Growth DCF and multistage DCF. Mr. Hevert placed primary reliance on his Constant Growth DCF and considered the substantial increases in the updated Constant Growth DCF model results by comparison to other models.

105. Mr. Kaml used a Constant Growth DCF and relied entirely on his original DCF results, which were based on data ending December 31, 2007. Dr. Amit and Mr. Hevert each updated their results with more recent data. The OAG offered additional information updating Mr. Kaml's calculations, but that information was offered after the evidentiary record had closed and on the last day for reply submissions. The information was stricken due to its untimeliness.

E. The ROE Recommendations.

1. Summary of the Company's ROE Recommendation.

106. OTP proposed an ROE of 11.25% based on Mr. Hevert's analysis. Mr. Hevert relied primarily on a Constant Growth DCF, which initially resulted in mean ROE figures of 10.78 and 10.82%.[126] Mr. Hevert also incorporated the results of his Capital Asset Pricing Model ("CAPM") analysis to arrive at the ROE figure. OTP contended that his analysis was corroborated by comparison to 43 recent ROE awards to vertically integrated utilities in other jurisdictions.[127] The results of Mr. Hevert's analyses, applied to the various proxy groups, are as follows:[128]

	Mean Low	Mean	Mean High
Hevert Revised Proxy Group	10.28%	11.51%	12.74%
Combined Proxy Group	10.15%	11.26%	12.37%
Amit Proxy Group	10.98%	12.38%	13.78%

[124] *See, Application of CenterPoint Energy*, Docket No. G-008/GR-05-1380, Commission Findings of Fact, Conclusions of Law, and Order at 31 (where the Commission adopted the recommendation of the Administrative Law Judge, rejecting the sole use of a multi-stage DCF model by CenterPoint Energy Minnesota Gas for the determination of cost of equity), *and* Administrative Law Judge Findings of Fact, Conclusions, and Recommended Order, Docket No. G-008/GR-05-1380 at 15-20. The Commission noted that a single-stage DCF had been performed, but the results discarded by CenterPoint as being "too low." *CenterPoint Energy*, supra, Commission Order at 31.
[125] Ex. 122, Amit Direct at 21-25; Ex. 17, Hevert Rebuttal at 17.
[126] Ex. 16, Hevert Direct, at 18.
[127] Ex. 17, Hevert Rebuttal, at 73-74.
[128] *Id.* at 73.

	Mean Low	Mean	Mean High
Kaml Proxy Group	9.70%	10.65%	11.61%
AVERAGE	10.28%	11.45%	12.63%

2. Comparable Groups.

107. Mr. Hevert and Dr. Amit used screening criteria that were generally similar. Mr. Kaml: (i) ignored factors that are available to investors and that are recognized as important by Value Line and Zacks; and (ii) included utilities that are dissimilar to OTP. The following table shows their respective comparable groups:

	Amit Group[129]	Hevert Updated Group[130]	Kaml Group[131]
DPL, Inc.			√
Edison International	√	√	
Empire District Electric	√	√	√
Entergy Corp.	√	√	
Pinnacle West Capital	√	√	√
Progress Energy	√	√	√
Westar Energy		√	√
Dominion Resources	√		
American Electric Power			√
Cleco Corporation			√
PNM Resources			√
Southern Company			√
Xcel Energy			√

[129] Ex. 124, Amit Surrebuttal, Schedule EA-S-4.
[130] Ex. 17, Hevert Rebuttal, (RBH-2), Schedule 1, page 2.
[131] Ex. 130, Kaml Direct, Schedule CDK-5.

108. *DPL*. Utilities that are subject to retail competition (such as DPL) have significantly different risks than vertically integrated utilities in Minnesota (such as the Company) that are not subject to such competition.[132] DPL should be excluded from the comparable group.

109. *Edison International*. Edison International ("EIX") was included by both Dr. Amit and Mr. Hevert, but excluded by Mr. Kaml because of the 2001 California energy crisis and EIX's suspension of dividends that ended in 2003.[133] There was no evidence these events have any bearing on investors' current perceptions of EIX.[134] The Value Line risk rating for EIX is 3 (on a scale of 1 to 5), which is the same as four of Mr. Kaml's comparables,[135] and Value Line states that: "On balance, EIX is an average utility investment."[136] Accordingly, EIX is appropriate for inclusion in the Comparison Group.

110. *Entergy*. Entergy was included by both Dr. Amit and Mr. Hevert, but excluded by Mr. Kaml because of a proposed restructuring.[137] OTP contended that Entergy should be included because: (i) it met all appropriate screening criteria; (ii) there was no indication of any significant effect on the price of Entergy stock; and (iii) a portion of the proposed restructuring was rejected more than one year ago.[138] Entergy is appropriate for inclusion in the Comparison Group.

111. *Cleco and Southern*. Mr. Kaml included both Cleco and Southern in his group. OTP and the Department maintained that the beta coefficients of these companies rendered them not comparable to OTP. Beta coefficients are appropriate screens that are used by investors.[139] Cleco and Southern should be excluded from the comparable group.

112. *PNM*. PNM announced agreements that involve the transfer of almost 25% of its assets in January 2008.[140] While this transfer was announced after the analyses were performed, excluding PNM for this reason is appropriate to maintain the most accurate analysis possible.[141]

113. *Xcel Energy*. Dr. Amit excluded Xcel Energy because it is not categorized as an electric company.[142] Mr. Hevert excluded Xcel Energy because a large portion of its revenues and earnings result from its regulated natural gas business.[143] A utility with substantial natural gas business is not comparable to OTP, which has no natural gas business. Xcel Energy should be excluded from the comparable group

114. *American Electric*. Mr. Hevert excluded American Electric because it did not meet his beta screen.[144] Dr. Amit excluded it because it is subject to retail competition.[145] Screens for beta and retail competition are appropriate. American Electric should be excluded.

115. *Westar*. Dr. Amit excluded Westar because of its SIC industry code.[146] Mr. Hevert included Westar because it met all of his screening criteria.[147] Excluding Westar results in

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[132] Ex. 122, Amit Direct at 9; Ex. 17, Hevert Rebuttal at 13.
[133] Ex. 130, Kaml Direct at 18.
[134] Ex. 17, Hevert Rebuttal at 39-40.
[135] Tr. V. 7 at 38.
[136] *Id.* at 39; and Ex. 136.
[137] Ex. 130, Kaml Direct at 18.
[138] Ex. 17, Hevert Rebuttal at 37.
[139] *Id.* at 35.
[140] *Id*. at 36.
[141] Tr. V. 7 at 42.
[142] Ex. 122, Amit Direct, Schedule EA-2.
[143] Ex. 17, Hevert Rebuttal at 36.
[144] Ex. 137, page 3.
[145] Ex. 122, Amit Direct, Schedule EA-7.

increases of Mr. Hevert's updated mean and high DCF results by 45 and 70 basis points respectively.[148]

116. *Dominion*. Dr. Amit included Dominion. Mr. Hevert excluded Dominion because of substantial revenues and earnings from non-regulated operations.[149] If Dominion was included, Mr. Hevert's updated mean and high DCF results would have increased by 42 and 39 basis points respectively.[150]

117. Both of Dr. Amit's and Mr. Hevert's comparable groups are appropriate. Of the two, Dr. Amit's provides the closest comparison to OTP. Adjusting Mr. Kaml's comparable group (by removing AEP, Cleco, DPL, PNM, Southern, and Xcel Energy) would increase his mean DCF by 25 basis points.[151]

3. Earnings Per Share Growth Forecasts.

118. The DCF model is based on *long-term* growth and assumes cash flows in perpetuity and a constant dividend payout ratio. In the long-run, book value per share ("BVPS") growth and dividend per share ("DPS") growth are derived from earnings per share ("EPS") growth.[152]

119. Dr. Amit and Mr. Hevert relied solely on EPS growth estimates. They maintained that this is appropriate because: (i) EPS growth is the only logical source of long term growth, as investors know;[153] and (ii) objective data demonstrates that EPS is the only growth estimate in which investors place sufficient reliance to affect the price of electric utilities' stock in general or the comparable companies considered by Dr. Amit, Mr. Hevert, and Mr. Kaml.[154]

120. Mr. Kaml gave equal consideration to BVPS and DPS growth rates. Mr. Kaml's use of BVPS and DPS growth rates reduced the results of a DCF analysis of his comparable group by 53 basis points. Mr. Hevert maintained that updating Mr. Kaml's data and focusing on EPS growth rates would increase his mean DCF result to 10.47%, before adjustment of his comparison group and inclusion of flotation cost recovery.[155]

121. Over the long-run, both BVPS and DPS are derived from EPS growth. While in the short run, expected growth rates of DPS, BVPS, and EPS may differ, the long-run expected BVPS and DPS growth rate must equal the EPS expected growth rates. As a result, expected EPS growth is the foundation of growth in the DCF model.[156] Since the DCF model assumes cash flows in perpetuity and a constant dividend payout ratio, EPS, rather than DPS or BVPS, is the appropriate measure of growth for the DCF model.[157]

122. Mr. Hevert contended that that EPS growth projections are the only measure of growth that have a statistically significant and meaningful effect on investors' stock purchase decisions (and resulting prices) for: (i) electric utility stocks in general; and (ii) the comparison

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[146] Ex. 17, Hevert Rebuttal at 13.
[147] *Id.*
[148] *Id.*
[149] *Id.* at 14.
[150] *Id.* at 15.
[151] Ex. 17, Hevert Rebuttal at 69.
[152] *Id.* at 41.
[153] Ex. 124, Amit Rebuttal at 5-6; and Ex. 17, Hevert Rebuttal at 40-41.
[154] Ex. 17, Hevert Rebuttal at 42-45.
[155] *Id.* at 69.
[156] Ex. 123, Amit Rebuttal at 6.
[157] Ex. 17, Hevert Rebuttal at 41.

companies used by Mr. Kaml, Dr. Amit, or Mr. Hevert. Mr. Hevert maintained that neither DPS nor BVPS growth rates had any statistically significant effect as a predictor of investors' stock valuations.[158]

123. Emphasizing EPS growth projections appropriate blends the need to use price data based on information that is as recent as possible, yet avoids the impact of significant short-term market fluctuations. The most recent 30-day period as used by Dr. Amit accomplished this purpose. The projected EPS growth rates are the appropriate growth rates to be used in a DCF analysis or a TGDCF analysis because long-term sustainable DPS growth rates are solely determined by the EPS growth rates.[159]

124. The Department relied upon the TGDCF to appropriately account for the fact that some of the projected EPS growth rates may not be sustainable in the long-run. (This same problem exists with the projected book value per share ("BPS") and dividend per share ("DPS") growth rates.) The Department's recommended ROE for OTP is the most appropriate and most reasonable ROE in this proceeding because it is the only ROE that used the most recent available dividend yields and projected growth rates, used the EPS projected growth rates which are the most appropriate to use in a DCF or TGDCF analysis, and accounted for the some of the projected EPS growth rates being unsustainable in the long-run.[160]

4. Dividend Yields.

125. Dr. Amit used a 30-day averaging period to eliminate the effect of potentially aberrational prices in the dividend yield calculation.[161] Mr. Hevert accepted a 30-day averaging period in his updated DCF analysis[162] and determined a dividend yield of 4.31%.[163] OTP, the Department, and the OAG all included a 1/2 year growth component,[164] to address the different times during the year when the companies in the comparison groups issued dividends.[165]

126. The dividend yields that were included in the data from which the OAG determined its ROE recommendation averaged about 4.41% for the three month period ending December 31, 2007[166] and subsequently increased to 4.54%.[167]

5. Updating of Data.

127. The Department noted that updating information in the DCF model is important since the model is a forward-looking assessment of the cost of equity. Because current stock prices incorporate all publicly available information, older data should be avoided.[168] The same assertion was made regarding growth forecasts, which should also match the period of the stock price information.[169]

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[158] *Id*. at 2-3, 41.
[159] DOC Ex. 122 at 15, and DOC Ex. 123 at 4-8.
[160] Department Brief, at 13-14.
[161] Ex. 122, Amit Direct at 46.
[162] Ex. 17, Hevert Rebuttal at 16.
[163] *Id.* at RBH-2, Schedule 1, page 2.
[164] *Id.* at 10, 33.
[165] Ex. 16, Hevert Direct at 15.
[166] See, Ex. 130, CDK-5.
[167] Ex. 17, Hevert Rebuttal, (RBH-2), Schedule 1, page 5.
[168] Ex. 122, Amit Direct at 14.
[169] Ex. 124, Amit Surrebuttal at 1.

128. Since more current information is now available than when the parties filed their direct testimony, the more current information should be used.[170] Dr. Amit noted the need for updated information in times of market changes and demonstrated that by reference to the irrelevance of data from late 2007 in the context of current capital market conditions.[171] Mr. Kaml acknowledged that it was important to use the most current information that is available.[172] He also acknowledged that the Commission typically uses updated information when it is available.[173] Mr. Kaml did not provide updated information, and had not reviewed more current information for his comparable group after the cut off of his data as of December 31, 2007.[174] Dr. Amit noted, however, that the impact of using his updated data was a "slight increase," amounting to 20 basis points difference in the ROE and only 10 basis points in the ROR.[175]

129. Market conditions have increased the cost of equity since the time of the parties' direct testimony, as reflected in the surrebuttal analyses of Dr. Amit, whose recommended ROE increased by 20 basis points[176] and in the rebuttal analyses of Mr. Hevert, whose mean DCF analyses increased by 51 basis points using the six companies in his revised comparable group.[177] Updated information alone would have increased Mr. Kaml's mean DCF by 25 basis points.[178] Including updated information is important for precision in rate setting, but the updating of information will not support adopting one model over another, since the differences are going to be insignificant compared to the differences in modeling.

6. Flotation Costs.

130. Mr. Hevert and Dr. Amit proposed recovery of flotation costs by the same "Amortization Method" that the Commission has used in prior cases. The evidence provided by the Company meets all of the criteria for flotation cost recovery in the *2004 Great Plains Rate Case*,[179] the *1994 Minnesota Power Rate Case*,[180] the *2005 Xcel Energy Rate Case*,[181] and under FERC standards.

a. Common Stock Issuance.

131. The recovery of flotation costs related to the issuance of common stock is closely analogous to the recovery of issuance costs for LTD. To deny recovery of common stock flotation costs because there was no common stock issuance planned for the test year would be comparable to allowing the recovery of LTD issuance costs only in years when the LTD debt was issued. There is no requirement that limits the recovery of those costs to LTD issued in the test year or to investments made in the test year, and there is similarly no logical basis to limit recovery of common stock flotation costs to common stock issued in the test year.[182]

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170 *Id.* at 2.
171 Tr. V. 7 at 70-71.
172 *Id.* at 41.
173 *Id.* at 42.
174 *Id.* at 41.
175 Ex. 124, Amit Surrebuttal at 2.
176 Ex. 124, Amit Surrebuttal at 2.
177 Ex. 16, Hevert Direct at 39; and Ex.17, Hevert Rebuttal at 73.
178 Ex. 17, Hevert Rebuttal at 69.
179 *Petition of Great Plains Natural Gas Company*, Docket No. G-004/GR-04-1487, ("*2004 Great Plains Rate Case*").
180 *ITMO the Application of Minnesota Power for Authority to Change its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E015/GR-94-001 ("*1994 Minnesota Power Rate Case*").
181 *Application of Northern States Power Company*, Docket No. E-002/GR-05-1428, ("*2005 Xcel Energy Rate Case*").
182 Ex. 17, Hevert Rebuttal at 46-47.

132. Common stock is closely analogous to LTD because: (i) both are issued primarily to provide financing for long-term investments; and (ii) both remain part of the utility's balance sheet for long periods of time. Common stock is also comparable to rate base, in that it remains part of the utility's cost of doing business long after the initial investment.

133. It is inconsistent to think of flotation costs as a cost that is appropriately recovered only if stock is issued in the test year. While a test year limitation is an appropriate requirement for when *expenses* have been incurred, it is *not* an appropriate requirement for when *long-term costs*, such as rate base or permanent capital have been incurred. Flotation costs associated with common stock issuances should be treated the same as issuance costs of LTD, which are amortized over the life of the LTD.[183]

134. The Amortization Method matches the recovery of the cost to the useful life of the capital, which is permanent with common stock. In contrast, the Current Recovery Method allocates all flotation costs to only current ratepayers, who receive only a portion of the benefits from new common stock issuances. The Current Recovery Method is counter to the basic principles of capital cost recovery under regulated rates.[184]

135. Under capital cost recovery principles, the cost recovery of an investment must be spread over the life of the investment to best match cost recovery with the benefits provided. Since the issued common stock remains on the utility's balance sheet and continues to provide benefits to ratepayers indefinitely, it is appropriate to recover flotation costs via the Amortization Method which matches the period of the benefit. Otherwise, current ratepayers would pay all the costs of an investment that continue to provide benefits for future ratepayers.[185] Mr. Kaml agreed that common stock proceeds are used to finance long-term investments and that the Current Recovery Method recovers all common stock issuance costs from current ratepayers.[186]

b. Dilution.

136. The purpose of a flotation cost adjustment is to prevent dilution and allow investors to earn their required rate of return even during years in which no new common equity shares are issued.[187] Dr. Amit demonstrated how dilution occurs with a mathematical model.[188]

137. Mr. Kaml asserted that the need for recovery of flotation costs should be limited to common stock issuances at less than book value.[189] However, the purpose of flotation cost recovery is to prevent dilution, and that dilution is based on the relationship of issuance proceeds received by the issuing utility to the *market value* of the stock, not the book value.

138. The authorized ROE should reflect the level at which the regulated utility is able to attract capital (*i.e.*, the market price). Accordingly, recovery of those issuance costs is needed so that the authorized ROE is not diminished by those costs.[190] Without recovery of flotation costs,

[183] Ex. 123, Amit Rebuttal at 10.
[184] *Id.* at 8.
[185] *Id.* at 9-10.
[186] Tr. V. 7 at 17-18.
[187] Ex. 123, Amit Rebuttal at 12.
[188] *Id.* at 12-13.
[189] Ex. 130, Kaml Direct at 28.
[190] Ex. 17, Hevert Rebuttal at 47-48.

the authorized ROE may not be earned because costs associated with the utility's common stock have not been recovered.[191]

c. Investment Plans.

139. OTP has provided evidence of investment plans that include $759 million of investments in total. Approximately $336 million of that investment relates to the proposed Big Stone II project.[192] The remaining $423 million relates to other projects, including $106 million for additional wind generation and related transmission.[193] OTP noted that its capital expenditure program is well above average and considerably more extensive than those undertaken by the proxy group companies. As a general matter, OTP maintains that the financial community recognizes that additional risks are associated with substantial capital expenditures.[194] OTP indicated that it will need sources of capital beyond its earnings to carry out its investment plans.[195] The OAG did not provide any evidence that would call into question OTP's investment plan or OTP's need to issue common stock to capitalize that investment plan.[196]

140. In raising new capital, continuing a high ratio of equity to total capitalization is needed for OTP to maintain its strong credit ratings.[197] New common stock will be needed to maintain a balance of debt and common equity since capitalizing the anticipated investment projects primarily through the issuance of debt instruments would substantially reduce the ratio of common equity to total capitalization.

d. Prior Commission Decisions.

141. The Commission has allowed recovery of flotation costs without a showing of an issuance of new common stock in the test year. To impose such a requirement would be comparable to allowing recovery of LTD issuance costs only in the year in which the LTD was issued.

142. In the *1994 Minnesota Power Rate Case*, the Commission explained why the need for flotation cost recovery is not limited to years in which an issuance occurs, stating:

> Issuance or flotation costs are not simply for use in years when the company is issuing common stock. They represent the difference between what the investors paid and the company received during public offerings, and, because there is no fixed life, as there is with a bond, they must be recovered through a return adjustment.[198]

In the *2005 Xcel Energy Rate Case*, the Commission recognized that such a requirement could impede the utility's ability to raise capital needed to fund investment, saying in part:

> In this case, the absence of affirmative, record evidence that Xcel plans to issue stock during the test year clearly cuts in favor of denying the entire 25-basis-point

[191] *Id.* at 48.
[192] *ITMO the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota*, PUC Docket Nos. ET-6131, ET-2, ET-6130, ET-10, ET-6444, E-017, ET-9/CN-05-619 ("*Big Stone II*").
[193] Ex. 15, Moug Rebuttal at 2.
[194] Ex. 17, Hevert Rebuttal at 27, 29.
[195] *Id.* at 3.
[196] Tr. V. 7 at 22-23.
[197] *Id*.
[198] *1994 Minnesota Power Rate Case,* FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 49 (November 22, 1994).

adjustment. At the same time, there is no affirmative, record evidence that the Company will not issue stock during that time, the parties did not address the issue, and the record contains many references to plans for an aggressive capital improvement program.

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>
> The commission has no intention of hindering Company efforts to raise capital for this program, parts of which are critical to maintaining system reliability and to implementing state policies promoting the development of renewable generation technologies … .[199]

143. The *2003 Interstate Rate Case,*[200] which was discussed in the *2005 Xcel Energy Rate Case*,[201] does not support the conclusion that flotation costs depend on test year stock issuances. In that case: (i) the utility did not request flotation cost recovery;[202] and (ii) the utility presented *no evidence* of *either* actual or projected issuance costs.[203] That case also reflected the unusual circumstance of the Commission rejecting a settlement because the ROE was too high.[204]

144. The *2004 Great Plains Rate Case* allowed flotation cost recovery based on the costs of *prior* equity issuances without any showing of common stock issuance during the test year.[205] Mr. Kaml recognized that the Commission has relied on utility plans to issue common stock, and has allowed flotation cost recovery without requiring a test year common stock issuance.[206]

e. Use of the Amortization Method.

145. The Commission uses the Amortization Method, which adjusts the dividend yield. This approach is comparable to the recovery of the issuance costs of LTD.[207] The Commission described and approved the Amortization Method in *2004 Great Plains Rate Case*,[208] as follows:

> The adjustment was made by dividing the expected dividend yield by (1 – percentage flotation costs).[209]

146. Mr. Kaml acknowledged that the Commission has used the Amortization Method when allows recovery of flotation costs.[210] Mr. Kaml also acknowledged the importance of precedent, stating: "Once one method is adopted, it must be continued."[211] The Amortization

[199] *2005 Xcel Energy Rate Case,* Commission Findings of Fact, Conclusions of Law and Order; Order Opening Investigation at 27 ("*2005 Xcel Energy Order*").
[200] *Petition by Interstate Power and Light*, Docket No. E-001/GR-03-767 ("*2003 Interstate Rate Case*").
[201] *2005 Xcel Energy Order* at 27.
[202] *2003 Interstate Rate Case*, Commission Findings of Fact, Conclusions of Law, and Order; Order Modifying Settlement at 7 (April 5, 2004).
[203] *Id*.
[204] *Id*.
[205] *See, 2004 Great Plains Rate Case*, Commission Findings of Fact, Conclusions of Law and Order at 10 (May 1, 2006) ("*Great Plains Order*").
[206] Tr. V. 7 at 23.
[207] Ex. 17, Hevert Rebuttal at 48.
[208] *Great Plains Order* at 11.
[209] *Id*. at 12.
[210] Tr. V. 7 at 24, 26.
[211] Ex. 38, Kaml Direct at 26; and Tr. V. 7 at 27.

Method used by Dr. Amit and Mr. Hevert complies with the Commission's prior decisions on this issue.[212]

f. FERC Requirements.

147. Mr. Kaml acknowledged that his proposed test year limitation was quite restrictive,[213] and that his recommendation is more severe and restrictive than what is required under the FERC standards.[214]

148. OTP's financial situation meets the FERC requirements for flotation cost recovery, even under the "Current Recovery Method." Under *Boston Edison*, flotation cost recovery was allowed based on a showing "that [the utility] will require external financing to complete its construction program"[215] and that it had a plan to issue common stock "during the next five years."[216]

149. The Company has demonstrated its need for common stock issuance in the next 5 years under its capital investment plan, which calls for an investment of approximately $739 million.[217] An award of flotation costs is appropriate under these circumstances.

150. With a $100 million common stock issuance and flotation costs of 4.41%[218] (as Dr. Amit found), the issuance costs would be $4,410,000 ($100,000,000 x 4.41%). The Company's $759 million investment plan over the next 5 years is very likely to require substantial common stock issuances.[219] Under the Current Recovery Method, all of those $4,410,000 costs would be recovered from current ratepayers, even though investments made with the $100 million would serve ratepayers for many years. Under the Amortization Method, a 20 basis point flotation cost adjustment determined by Dr. Amit[220] would add approximately $341,000 to the revenue requirement[221] and the 18 basis point flotation cost adjustment determined by Mr. Hevert[222] would add approximately $307,000 to the revenue requirement.[223] The Amortization Method provides a far better match of costs and benefits for ratepayers.

F. Other ROE Awards.

151. OTP maintained that ROE recommendations of the Department and the Company are corroborated by mainstream of other decisions relating to vertically integrated utilities, such as OTP.[224] OTP contrasted Mr. Kaml's ROE recommendation as being lower than *any* authorized rate award of 42 awards in jurisdictions that have not adopted electric restructuring at the retail

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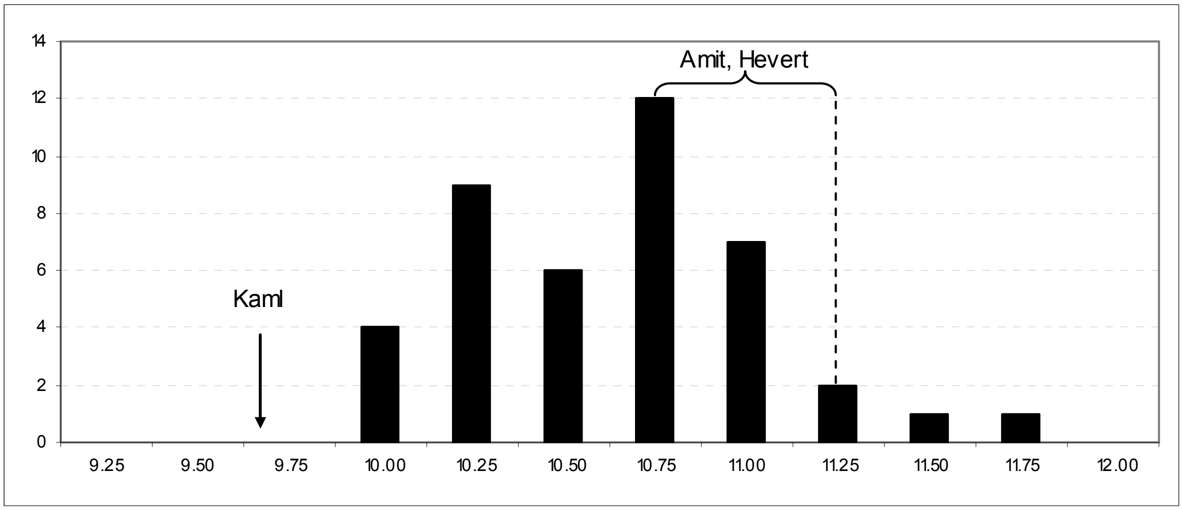
[212] Ex. 17, Hevert Rebuttal at 49.
[213] Tr. V. 7 at 20.
[214] *Id.* at 20, 22.
[215] *Boston Edison Company*, 66 FERC ¶ 63,013 at 65,081; 1994 WL 995669 (F.E.R.C., 1994) at 31.
[216] *Id.*
[217] Moug Rebuttal at 2-3.
[218] Ex. 123, Amit Direct, Schedule (EA-15).
[219] Ex. 15, Moug Rebuttal at 2; Ex. 17, Hevert Rebuttal at 27, 29.
[220] *See*, Ex. 125, Amit Surrebuttal Schedule (EA_S-4).
[221] $100,000,000 x 20 basis points x 1.705611 = $341,120.
[222] Ex. 17, Hevert Rebuttal (RBH-1), Schedule 1 at 2.
[223] $100,000,000 x 18 basis points x 1.705611 = $307,000.
[224] Ex. 17, Hevert Rebuttal at 2.

level from 2006 through 2008. Presented graphically, OTP described the comparison as follows:[225]



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The results of many cases (42 cases since 2006) eliminate any realistic possibility that unusual facts could explain all of these results. As a result, the ROE awards in other states provide a useful benchmark to corroborate the results of the record in this proceeding.[227]

152. The Commission has considered ROE awards from other jurisdictions in making its own awards. The reasons for such consideration were recently stated as follows:

> Third, as the ALJ herself suggested, the Commission has taken administrative notice of a list of updated ROE decisions from other jurisdictions provided by the Company. The ALJ suggested that updated information on those decisions might support adjusting her 9.5 percent ROE recommendation upward. While the probative value of ROEs set in other jurisdictions is limited because the record does not allow the Commission to assess the differing regulatory circumstances affecting those awards, they do provide some window to national context and, as such, can serve a limited function as a check on reasonableness.[228]

153. Using the comparison of other jurisdiction's awards as a check on reasonableness provides further support for the Department's position on ROE. The Department's proposed ROE is near to both the mean and median awards over the entire survey of awards since 2006. While such a survey cannot substitute for a reasoned, transparent determination of ROE, the survey can provide reassurance that the choices made in making that determination were sound and economically justified. By contrast, OTP's proposed award of ROE would be among the three highest since 2006. OAG's proposed award of ROE would be the lowest over that same period.

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[225] *Id.* at 4, updated to Dr. Amit's 10.91% ROE recommendation; Source: SNL Interactive. *See* Appendix A to Exhibit 17.
[226] Ex. 17, Hevert Rebuttal at 4. Chart 1.
[227] Ex. 16, Hevert Direct at 24.
[228] *ITMO the Application of Northern States Power Company, a Minnesota Corporation and Wholly Owned Subsidiary of Xcel Energy Inc., for Authority to Increase Rates for Natural Gas Service in Minnesota*, PUC Docket No. G-002/GR-06-1429, at 36-37 (Commission Findings of Fact, Conclusions of Law, and Order issued September 10, 2007) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=4768622).

154. OTP also noted that PNM debt securities were downgraded to non-investment grade levels (a/k/a "junk") by Fitch within days of a recommended decision by a New Mexico hearing examiner that included a ROE of 9.71%.[229] OTP recognized that any downgrade is possibly the result of multiple factors, but maintained that the recommended 9.71% ROE must have been a contributing factor.[230] Using investor reaction to an ROE award is another method of assessing the range of reasonableness of proposed awards.

G. ROE Recommendations.

155. The competing recommendations for an award of ROE are as follows:[231]

	Low	Mean	High
Hevert Constant Growth DCF	10.28%	11.51%	12.74%
Amit Two Growth DCF	9.90%	10.91%	11.85%
Kaml Constant Growth DCF	Not calculated	9.69%	Not calculated

156. Mr. Hevert's 11.25% ROE is based primarily on his Constant Growth DCF analyses, reflects his updated Multistage DCF and CAPM results. The Department and OAG-RUD have identified significant factors that have not been adequately accounted for in the Hevert analyses. Even the effort to show that his results are corroborated by the mainstream of ROE awards from other jurisdictions for vertically integrated electric utilities indicates that the Hevert ROE recommendation is too high and should not be adopted.

157. Mr. Kaml's analysis and ROE recommendation are very unlike the recommendations of either Dr. Amit or Mr. Hevert, and is an extreme outlier from the mainstream of ROE awards in other states. Updating Mr. Kaml's data, eliminating DPS and BVPS growth rates, removing dissimilar utilities, and applying the Amortization Method for flotation costs would lead to a 10.91% ROE, which is consistent with the rate calculated on behalf of the Department.[232]

158. Dr. Amit's 10.91% ROE is supported by his Two Growth DCF and CAPM analysis. The Amit analysis is well supported by factors that have consistently been relied upon by the Commission in setting utility rates. The proposed 10.91% ROE is reasonable and should be awarded to OTP.

H. Conclusion.

159. The Department's proposals for capital structure, ROE and ROR are fair and reasonable and should be adopted:

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[229] Tr. V. 7 at 52-53.
[230] The OAG cited a 9.10% ROE for Orange and Rockland (a Consolidated Edison subsidiary) as representative of investor expectations. Ex. 131, Kaml Surrebuttal at 6. However, a 9.10% ROE for Consolidated Edison of New York also led to a downgrade of its debt securities. Tr. V. 7 at 52.
[231] Ex. 17, Hevert Rebuttal at 73; Ex. 124, Amit Surrebuttal at 6; and Ex. 130, Kaml Direct at 31. Mr. Kaml did not calculate low or high DCF results, but rather stated that a range was 50 basis points above and below his mean DCF results.
[232] Ex. 17, Hevert Rebuttal at 69-70.

	Percent of Total	Cost	Weighted Cost
Short Term Debt	4.1%	6.52%	0.27%
Long Term Debt	42.3%	6.32%	2.67%
Preferred Stock	3.6%	4.75%	0.17%
Common Equity	50.00%	10.91%	5.46%
Total (ROR)	100.0%		8.57%

IV. WHOLESALE MARGINS.

160. The treatment of wholesale margins for rate making purposes is divided into three subject areas: asset-based margins, non-asset based margins, and ancillary service market ("ASM"). Each subject area raised issues that will be addressed separately.

A. Asset-Based Margins.

161. Asset-based margins result from OTP's sale of energy that is not needed to serve OTP retail needs. The cost of assets used to generate the energy sold into the market is included in rates. Since ratepayers are incurring the cost of the assets generating these margins, there is no disagreement that the treatment of asset-based margins must benefit the ratepayers. In spite of this agreement, there are three issues concerning the treatment of asset-based margins: (1) whether asset-based margins should be credited to the base rate revenue requirement or the fuel cost revenue requirement; (2) if asset based margins are credited to the base rate revenue requirement, what level of asset-based margins should be credited; and (3) whether asset-based margins that exceed the amount credited to the base rate revenue requirement should be paid to ratepayers through the fuel clause.

1. How Asset-Based Margins Should Be Credited.

162. In its initial filing, OTP proposed paying 100% of the asset-based margins through the fuel clause adjustment ("FCA"). OTP proposed paying 100% of asset-based margins through the FCA because the Commission approved an FCA sharing mechanism for asset-based margins in the *2005 Xcel Energy Rate Case*[233] and the IPL rate case (Docket No. E017/GR-05-748).[234] MCC also supported crediting asset-based margins to the fuel cost revenue requirement.[235]

163. In their Direct Testimonies, the Department and the OAG proposed that asset-based margins be credited instead to the base rate revenue requirement.[236] The Department stated that this was appropriate because OTP's asset-based margins are consistent in amount from year to

[233] *ITMO the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota,* Docket No. E-002/GR-05-1428 (Commission Findings of Fact, Conclusions of Law, and Order; Order Opening Investigation issued September 1, 2006) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3285507)("*2005 Xcel Energy Rate Case*")
[234] Ex. 10, Brause Rebuttal at 4-5.
[235] Ex. 61, Schedin Direct at 26.
[236] Ex. 96, Campbell Direct at 23; and Ex. 79, Lindell Direct at 5-6.

year, making it possible to determine a reasonable amount of credit.[237] The OAG proposed a credit to the base rate revenue requirement to provide the Company an incentive to obtain margins equal to the amount of credit, and to reduce the magnitude of the increase in base rates.[238]

164. OTP agreed to credit asset-based margins to the base rate revenue requirement, as long as the fixed credit amount is reasonable.[239] MCC did not address this issue in its Rebuttal Testimony and apparently does not oppose crediting the asset-based margins to the base rate revenue requirement.[240]

165. Crediting asset-based margins to the base rate revenue requirement is appropriate, conditioned on a reasonable fixed credit amount.

2. Selecting a Reasonable Fixed Credit.

166. OTP proposes using the historical average of asset-based margins received in 2003, 2004, 2006 and 2007 to determine the amount of credit ($5.009 million) to the base rate revenue requirement. The Department proposes using the same historic period but includes 2005 in determining the amount of the credit ($5.197 million). The OAG proposes crediting the amount of wholesale margins received in 2006 ($5.745 million).

167. One of the advantages of crediting the full amount of asset-based margins to the fuel cost revenue requirement is that it eliminates the need to select a reasonable amount to credit to the base rate revenue requirement. If the amount of the credit to base rates is too large, then the Company's revenue requirement will be unfairly low. Conversely, if the credited amount is set too low, the revenue requirement will be unreasonably high.

168. OTP, the Department and the OAG each proposed a different amount of base rate credit. The following table shows the historical amount of asset-based margins.

Year	Amount
2002	$2.376 million
2003	$4.339 million
2004	$4.292 million
2005	$5.953 million
2006	$5.745 million
2007	$5.658 million[241]

169. The Department and OTP are in agreement except for the treatment of 2005 in the historical average. The Department excluded the 2002 margins because they were comparatively lower. OTP excluded 2002 because it was the first year of MISO operations, which resulted in the amount of asset-based margins received in 2002 being significantly below those of subsequent years.[242]

[237] Ex. 96, Campbell Direct at 23.
[238] Ex. 79, Lindell Direct at 5-6.
[239] Ex. 10, Brause Rebuttal at 4.
[240] Tr. V. 3 at 163, Schedin.
[241] Ex. 11, Brause Rebuttal at 5. Some of this information was originally filed as trade secret because the 2007 financial information had not been released at that time to the financial community. It has subsequently been released and is no longer trade secret.
[242] Ex. 10, Brause Rebuttal at 5.

170. OTP excluded 2005 asset-based margins because 2005 was the first year of MISO Day 2, and OTP maintained that it did an excellent job of anticipating the market opportunities that were presented in that year. With each subsequent year, OTP's margins have been smaller, reflecting the changes in MISO Day 2 operations and the increasing sophistication of the other market participants.[243]

171. The OAG argues that 2006 is representative because the margins received in that year were less than those received in 2005, and more than those received in 2007. The OAG offered no evidence that the asset-based margins received in 2006 will be replicated in future years.

172. Because of the volatility of asset-based margins, using the mean results over the longer period as proposed by OTP and the Department is reasonable. Both 2002 and 2005 are appropriately excluded as outliers from the range of results that are likely to be experienced by OTP in upcoming years. A fixed sharing margin credit of $5.009 million is reasonable.

3. The OAG Proposal to Pass Additional Asset-Based Margins through the FCA.

173. The OAG proposed that any asset-based margins in excess of the credited amount be paid to ratepayers through the FCA. Under the OAG proposal, if actual margins are less, the Company would absorb the loss. Conversely, if there are additional margins in excess of the amount of the credit, those would be paid to the ratepayers. In comparison, under the Company's and Department's proposals, any additional margins would be applied to meet OTP's future revenue requirement, offsetting some of the effects of inflation and other cost increases and delaying the need for a rate case. This treatment was used by OTP from 2003 through 2007 to delay the need for a rate case.[244]

174. The OAG maintained that asset-based margin "transactions create costs for ratepayers, including higher costs for plant in service, higher inventories of fuel, materials and supplies, depreciation and other costs."[245] OTP responded that if costs did increase as a result of asset-based margin transactions between rate cases, the Company could not recover those cost increases except by filing another rate case.[246] OTP contended that ratepayers were not harmed by the additional sales. To the extent that those costs increased between rate cases, OTP maintained that it should be allowed to use the associated margins to cover those cost increases.

175. Normally, both the utility and the ratepayers accept the risk that expenses or revenues will be higher or lower between rate cases. As a general matter, there is no accounting or true-up between an awarded rate of return and the rate of return actually experienced over the period between rate adjustments. The OAG's proposal to pay any additional margins to the ratepayers unbalances that risk.

176. As a general principle, the Commission sets rates using a test-year matching concept. Revenues and expenses within a 12 month test period are matched to determine rates. The OAG's proposal would require payment of "excess" revenues from asset-based margins without a determination that OTP's base rates were excessive. As a result, the OAG's proposal violates the prohibition against single item ratemaking, which prevents a change in rates based on a change in a single cost or revenue.

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[243] *See id.*
[244] Ex. 8, Brause Direct Table 1 at 8.
[245] Ex. 79, Lindell Direct at 7-8.
[246] Tr. V. 5 at 63, Campbell.

177. The Commission's policy against single-issue ratemaking was affirmed by the Minnesota Court of Appeals in *Matter of Minnesota Power's Transfer.*[247] The Commission had approved a utility's transfer of two generating units to the City of Duluth, but refused to adjust that utility's rates to reflect the transfer. In affirming the Commission's decision, the Court stated:

> The PUC could not have simply removed the transferred property from Minnesota's rate base and reduced its rates accordingly. Minn. Stat. § 216B.23, subd. 1, requires not only a finding that current rates are unreasonable before setting new ones, but also that the new rates be reasonable. For the PUC to act as Hanna requests would be to ignore both requirements: the record does not show that Minnesota Power's rates are unreasonable solely because of the transfer, and removing the property from its rate base would not be "determining and fixing" reasonable rates as required by the statute.[248]

178. The OAG's proposal is not in keeping with Commission precedents for appropriate treatment of revenues and expenses. If the Commission prefers to assure that ratepayers receive the actual level of wholesale margins received by OTP, then the Commission should adopt the OAG's proposal with the modification that all asset-based margins be used to provide a credit to the fuel clause revenue requirement, as has been approved for Xcel Energy and IP&L.

179. Should the Commission choose to provide a credit to base rates, as proposed by the Department, then the Commission should approve a credit of $5.009 million, with no pass through of additional margins through the FCA.

B. Non-Asset Based Margins.

180. Non-asset based margins result from the unregulated purchase and sale of energy for non-retail purposes. Both asset-based margins and non-asset based margins are conducted by the same OTP marketers, sharing common equipment. Therefore, it is appropriate for non-asset based margins to cover their incremental costs and provide a reasonable contribution towards common costs. The primary disputed issue related to non-asset based margins is the level of contribution to require that will cover those incremental and common costs.

181. As with asset-based margins, there are two primary methods for compensating ratepayers for this activity, a credit to base rates or payments made through the FCA. Unlike asset-based margins, all of the parties propose that payments for non-asset based margins be made through the FCA. The difference is largely because the amount of non-asset based margins is volatile and risky. Non-asset based margins can even reflect net losses. For that reason, only net positive margins are to be shared with ratepayers on an annual basis.[249]

182. Prior to the test year, OTP provided a credit to the base rate revenue requirement by moving regulated costs below the line. In 2006, OTP credited the base rate revenue requirement by moving $993,173 of regulated costs below the line. This credit was determined based on volumes and not costs.

183. OTP proposed modifying its practice for the test year in two respects. First, it proposed moving from providing a credit to base rates to providing a credit to fuel costs. Second,

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[247] *In the Matter of Minnesota Power's Transfer of M.L. Hibbard Units 3 and 4 Boilers and Related Facilities to the City of Duluth*, 399 N.W.2d 147 (Minn. Ct. App. 1987).
[248] *Id.* at 151.
[249] A comparison of OTP's 2006 non-asset margins of $1,773,864 (Ex. 20, Beithon Direct at 30) with its 2007 non-asset margins (Ex. 11, Brause Rebuttal at 8) demonstrates the high level of variability.

it proposed using a percentage of margins rather than volumes in determining the amount of the credit. OTP has shown that using a percentage of margins is superior to using volumes as the mechanism for establishing the amount of the credit.

184. OTP proposed paying 10 percent of its non-asset based margins (non-regulated profits) to the ratepayers, by passing those margins through the fuel clause. In Docket No. E002/GR-85-1428, Xcel Energy's proposal to share 25 percent of the margins, coupled with Xcel Energy bearing the full risk that non-asset based margins might be negative, was presented to the Commission in a settlement that the Commission approved.[250]

185. OTP has comparatively greater non-asset based margins than Xcel Energy. For that reason, OTP's proposal of 10 percent provides significantly more cost support than does Xcel Energy's 25 percent payment. Comparing OTP's proposal at 10 percent of margins to Xcel Energy at 25 percent of margins using three different measures results in the following:

per customer	2.9 times larger
per kWh	2.25 times larger
per retail revenue dollars	2.5 times larger[251]

186. The OAG proposed that the 25 percent sharing used by Xcel Energy be required of OTP.[252] The OAG offered two explanations for its position. First, OTP's analysis in its Direct Testimony did not consider the difference in the mix of customers.[253] The table in the foregoing finding shows that the concern is unfounded. On a per kWh basis (which eliminates customer differences entirely), OTP's proposal is 2.25 times more generous than the Xcel Energy proposal. Second, the OAG maintained that OTP only provided comparison information for 2006. OTP responded that small variations from year-to-year in each utility's performance in non-asset based activities were possible, but that such variations would not change the ultimate conclusion that OTP's proposal is significantly more generous.[254]

187. The Department accepted OTP's proposal to pay 10 percent of the non-asset based margins through the fuel clause. However, the Department also proposed to credit $993,173 to the base rate revenue requirement.

188. Crediting $993,173 to the base rate revenue requirement would be a fixed credit based on volumes of non-asset sales during 2006. OTP maintained that this figure is a snap shot amount that ignores the volatility and risk (since annual margins could be negative) associated with non-asset based margins. OTP asserted that requiring a fixed credit to base rates is inconsistent with the Department's justification for providing a percentage credit to the fuel cost revenue requirement.[255]

189. The Department maintained that the $993,173 credit is based on a determination of non-regulated costs, pursuant to the standards set out in Docket 1008.[256] OTP indicated that this

[250] Tr. V. 5 at 54-55.
[251] Tr. V. 1 at 53.
[252] Ex. 29, Lindell Direct at 8.
[253] *Id.*
[254] Ex. 10, Brause Rebuttal at 9.
[255] *See id.* at 33.
[256] Department Brief at 35-36.

was the amount of regulated costs that OTP moved below the line in 2006 to provide a credit to the base revenue requirement. OTP indicated that the amount was not based on a cost analysis. [257]

190. OTP asserted that even if volumes were the appropriate allocator for determining credits, applying Docket 1008 principles does not support first allocating costs and then also taking 10 percent of the profit of the non-regulated business activity.[258]

191. OTP characterized the Department's proposal as the equivalent to crediting 48 percent of these margins.[259] As stated by Mr. Brause:

> The Department's approach would create a subsidy to the ratepayers and would be confiscatory. Consequently, it would reduce, if not remove entirely, OTP's reasons for engaging in this highly risky enterprise. If OTP ceases this activity, its costs are not expected to decrease materially and certainly would not decrease by an amount equal to 10 percent of the anticipated margins. As recognized in the approved Xcel Energy settlement, utilities are not required to engage in this unregulated business.[260]

192. The MCC proposed that 30% of the non-asset based margins be paid to the ratepayers, based on an attempt to create a fully allocated cost requirement for this activity.[261] OTP maintained that the extent of commingling sales activities for both asset-based and non-asset sales made determination of a stand-alone cost for either activity virtually impossible.

193. OTP identified several problems with the MCC methodology. All incentive payments were removed in direct conflict with the MCC's other testimony that it is appropriate to pay incentives to marketers. Loading factors were inappropriately applied to incentives, when labor costs already recovered those loadings (double counting costs). An "office space" charge was applied without any support for that charge. The entire "office space" charge was added to the Minnesota portion of the non-asset based activity greatly inflating the costs assigned to the non-asset based activity. [262]

194. OTP contended that adequately covering its incremental cost while providing some contribution to common costs from non-asset based margins is consistent with public interest. Where the margin sharing is too high, OTP maintained continuing this highly risky activity will be jeopardized and all ratepayer benefit eliminated.

195. If the Commission approves a payment mechanism that flows margins through the fuel clause, and does not also credit $993,173 to the base rate revenue requirement, then it is appropriate to make the fuel clause payment provisions effective with the date interim rates went into effect. This allows the treatment of non-asset based margins used in determining final rates to also be used for the purposes of determining the interim rate refund.

C. Ancillary Service Market Margins.

196. ASM margins include margins from spinning reserves, regulation reserves and supplemental reserve requirements. OTP and the Department propose that 80% of any such ASM

[257] Ex. 10, Brause Rebuttal at 6.
[258] *Id*.
[259] Ex. 10, Brause Rebuttal at 8.
[260] *Id.*
[261] *Id.*
[262] Ex. 10, Brause Rebuttal at 10.

margins be paid to ratepayers through the FCA. The parties indicated that this is the same treatment of ASM margins approved by the Commission for Xcel Energy. OTP has not previously had any ASM margins and agreed to implement such sharing within 60 days after OTP begins receiving such revenues. The only limitation would be a delay to the start date if OTP determines that beginning within 60 days is not technically feasible.[263] OTP committed to addressing any lag resulting from such a delay upon implementation.[264]

197. OTP agreed to revisit this treatment of ASM margins once MISO Day 3 begins.[265]

198. The OAG requested that 100 percent of all ASM margins be paid to ratepayers because they are provided using ratepayer funded assets. OTP agreed that ASMs are a form of asset-based margins. OTP also does not currently engage in this activity. Providing OTP an incentive to derive additional revenues from this activity would benefit the ratepayers. Affording OTP the ability to retain 20 percent of the margins is a reasonable incentive.

199. While OTP may be required to engage in these activities in the future under MISO Day 3, the details and nature of those activities are not currently known, and if a change is appropriate based on better knowledge, OTP has agreed that a prospective change would be appropriate.[266]

D. Future Carbon Credits and Renewable Energy Credits.

200. The MCC proposed that OTP be required to share future carbon credits and Renewable Energy Credits (RECs).[267] OTP maintained that, until more is known about how these markets will be structured and how utilities will participate in them, requiring a sharing mechanism is premature. OTP asserted that these are issues that should be addressed for all Minnesota utilities, not just OTP.[268]

201. The MCC provided no specifics on its proposal. The Commission only recently began addressing the trading of carbon credits and RECs. The Commission has declined to address the issue of cost recovery.[269] MCC's proposal should not be adopted as part of this proceeding.

E. Reporting Requirements.

202. OTP accepted the Department's request that: (1) OTP report all revenues and expenses for asset-based margins in the Jurisdictional Report; (2) non-asset based revenues and expenses would not be reported; and (3) OTP would provide the Department with such information needed to ensure accuracy in reporting both asset- and non-asset based wholesale margins. OTP further agreed to work with the Department to clarify the details for providing this information. These agreements should be adopted as part of this rate setting proceeding.

[263] Tr. V. 1 at 52 and 82.
[264] *Id.* at 82.
[265] Ex. 12, Brause Surrebuttal at 2.
[266] Tr. V. 1 at 56-57, Brause.
[267] Ex. 60, Schedin Direct at 27.
[268] Ex 10, Brause Rebuttal at 10.
[269] Ex 10, Brause Rebuttal at 10.

V. MISO COSTS.

203. The Midwest Independent System Operator ("MISO") is a regional transmission organization (RTO). The Commission has described the duties of an RTO as follows:

> MISO divides its operations into categories, including "Day 1" operations (dealing with security, outages, tariffs, transmission-line congestion and energy imbalances, billings and settlements, and market monitoring) and "Day 2" operations (implementing a competitive wholesale market for electricity, including locational marginal pricing and financial transmission rights).[270]

204. The only disputed issue between the parties regarding MISO operations is whether OTP should be allowed to recover its deferred MISO Schedule 16 and Schedule 17 Day 2 charges for the period of April 2005 to the implementation of interim rates.

205. MISO's cost of administering its Day 1 activities are recovered through its Schedule 10 charges. Mr. Beithon provided a detailed description of the MISO Day 1 activities along with a discussion of the resulting costs and benefits.[271] The Commission has approved full cost recovery of Schedule 10 charges in the two most recent electric rate cases (IP&L, Docket No. E001/GR-05-748 and *2005 Xcel Energy Rate Case*). No party objected to OTP recovering its Schedule 10 costs.

206. The Commission has determined that utilities, including OTP, can recover MISO Day 2 costs through the FCA, with the exception of MISO Schedule 16 and 17 charges.[272] Schedule 16 and 17 charges were determined to be administrative and not energy in nature. For that reason, Schedule 16 and 17 costs are recovered through base rates rather than through the FCA. The Commission described this cost recovery mechanism as follows:

> Each petitioning utility may use deferred accounting for MISO Schedule 16 and 17 costs incurred since April 1, 2005 [the start of Day 2]. Each utility may continue deferring Schedule 16 and 17 costs without interest until the earlier of the utility's next electric rate case or March 1, 2009.[273]

207. OTP is seeking to recover both its 2006 test year Schedule 16 and 17 costs of $329,239 and its deferred Schedule 16 and 17 costs of $292,895. OTP provided a detailed description of MISO Day 2 activities, including a cost/benefit analysis.[274] The Department requested that OTP provide additional information concerning costs, avoided costs, revenues and lost revenues.[275] In response, OTP provided additional information on both the actual costs incurred and the revenues received. OTP was not able to provide information on what the Company's energy costs would have been in the absence of MISO. OTP explained the absence of information as follows:

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[270] *ITMO Xcel Energy's Petition for Affirmation that MISO Day 2 Costs are Recoverable Under the Fuel Clause Rules and Associated Variances, et al*, Docket No. E-002/M-04-1970 (Commission Order Authorizing Interim Accounting For Miso Day 2 Costs, Subject To Refund With Interest issued April 7, 2005) (http://www.puc.state.mn.us/docs/orders/05-0025.pdf).
[271] Ex. 20, Beithon Direct at 42-46.
[272] *Order Establishing Accounting Treatment for MISO Day 2 Costs*, PUC Docket No. E017/M-05-284 (December 20, 2006) ("*MISO Day 2 Order*").
[273] *MISO Day 2 Order* , Ordering Paragraph 2.
[274] Ex. 20, Beithon Direct at 46-55.
[275] Ex. 96, Campbell Direct at 11.

Wholesale energy prices are dependent on a large number of factors for the MISO regions. Some of those include:

- Overall balance of supply and demand;
- Prices for generating station fuels (coal, natural gas, and oil);
- Generating station availability;
- Transmission line availability;
- Weather patterns;
- Non-conforming load requirements; and
- Availability of hydro resources.

Determining the Company's avoided energy costs and lost revenues would involve replicating accurately all of the factors identified above in the context of a pre-Day 2/pre-MISO environment. It is simply not possible to know these factors, because it is not possible to eliminate the impact that MISO had on the market.[276]

208. OTP's cost/benefit analysis of those costs that could be quantified demonstrated that OTP had:

- $1.9 million in avoided transmission charges for capacity purchases;
- $1.5 million reduction in the need for spinning reserves;
- $6.7 million avoided due to a much needed method of addressing OTP's obligations to supply regulation and load following services to generators in its control area; and
- $2.0 million in additional transmission revenues.

209. OTP has demonstrated benefits exceeding $12 million; compared to the 2006 test year costs of $329,239 and the deferred Schedule 16 and 17 costs of $292,895.[277] In response, the Department modified its position and agreed that the benefits of MISO Day 2 outweigh the costs and consequently the 2006 test year costs of $329,239 should be approved.[278]

210. While the Department concludes that the benefits of Day 2 exceed the costs for the purpose of allowing cost recovery of 2006 test year Schedule 16 and 17 costs, it asserts that none of the deferred Schedule 16 and 17 costs should be recovered. Ms. Campbell argues that wholesale margins were not shared with ratepayers during the deferral period of April 2005 to November 1, 2007 (the date interim rates took effect), and that energy costs increased during the deferral period while the "wholesale sector reaped significant profits gained through MISO Day 2."[279] OTP asserted that the Company shared wholesale margins during the 2005-2007 deferral period in the same manner that justified allowing recovery of the 2006 test year amount; and that OTP properly allocated Schedule 16 and 17 costs to the wholesale sector.

[276] Ex. 22, Beithon Rebuttal at 21.
[277] *Id*. at 23.
[278] Ex. 98, Campbell Surrebuttal at 2.
[279] *Id*. at 4.

211. OTP has demonstrated that the deferred Schedule 16 and 17 costs of $292,895 are appropriate for recovery.

A. Wholesale Margins Benefits during the Deferral Period.

212. OTP maintained that, during the deferral period of 2005 to 2007, OTP credited the full amount of asset-based margins to the base revenue requirement. From this contention , OTP maintains that this treatment of asset-based margins is identical to that proposed by the Department in this proceeding.

213. Mr. Brause explained how asset-based margins had been shared from 2003 and until 2007 as follows:

> As shown on …Table 1, on page 8 of my direct testimony,[280] retail customers received a significant benefit from asset-based margins. That table shows that we shared those revenues by using them to allow sufficient earnings to avoid a rate increase as early as 2003. If we had directly paid those revenues to the ratepayers, we would have needed an increase in base rates by an equal amount.
>
> This point is easily demonstrated by comparing our revenue requirement when asset-based margins are used as a credit to base rates compared to our revenue requirement if asset-based margins are passed through the FCA, or fuel clause adjustment. Our initial revenue requirement was 14.5 million based on sharing the margins through the FCA. That revenue requirement is reduced to 8.7 million when asset-based revenues are shared as a credit to base rates.
>
> In either case asset-based margins are shared with ratepayers. But when they are passed through directly to payers [sic] instead of as a credit to base rates, these base rates need to be increased.[281]

Mr. Brause further explained:

> [B]eginning with 2003 we likely would have been in for a rate case.
>
> Q. … With margins, wholesale margins, the Company earned, if I'm correct 10 percent in 2006?
>
> A Correct.
>
> Q. What would they have earned without margins in 2006?
>
> A A little less than 7 percent.
>
> Q. In your opinion was the Company sharing margins with ratepayers in 2006?
>
> A. Absolutely.
>
> Q. And why is that?

[280] Ex. 8, Brause Direct at 8.
[281] Tr. V. 1 at 51, Brause.

A. Because the customer did get the benefit of that. Had we had returns above 12 percent, then I can say that we were sharing it with the shareholder.[282]

Using the volumetric allocator, OTP charged regulated costs to the non-asset based margin activity.[283] OTP maintains that this practice had the same effect as a credit to the base rate revenue requirement of a portion of the non-asset based margins. OTP asserted that this practice reduced the base rate revenue requirement, thus improving earnings and reducing the need for a rate adjustment.

214. The Department maintained that OTP's assertions were "speculative and conclusory, yet unsupported . . . ."[284] The Department noted that OTP never decreased its rates during this period to pass through any margins from asset-based sales.[285] The Department strongly disagreed with OTP's conclusion. The Department noted that OTP's calculation of its revenue requirement in its jurisdictional reports for the years between rate cases have not been audited to the degree that rate cases are audited.[286]

215. The Department asserted that OTP's retention of asset-based margins did not defer the need for a rate increase. Rather, the Department contended that its recommendation and the Commission's Order in the *Hotline Complaint Docket* required OTP to file the current rate case.[287] The Department noted that OTP experienced problems with its allocations, an Allowance for Funds Used During Construction (AFUDC) correction and affiliated-interest concerns, noted in the *Hotline Complaint Docket*.[288] For these reasons, the Department asserted that OTP's need to file a rate case during the years 2003-2007 was not deferred due to the impact of asset-based margins.[289]

216. The underlying financial situation of OTP supported a need for a rate increase in 2006 and 2007. Nothing in the record of this matter suggests that OTP's financial situation in 2005 was materially different. OTP has adequately demonstrated that its ratepayers benefited from the OTP's treatment of asset-based and non-asset based margins in 2005 to 2007 in the same manner as they will benefit from those margins going forward. For these reasons, the Department's position, that wholesale margins must be shared in order to justify OTP's recovery of its deferred MISO Schedule 16 and 17 charges, has been satisfied.

B. Appropriate Share of Schedule 16 And 17 Costs to Allocate to Wholesale.

217. The Department's position, that deferred Schedule 16 and 17 costs should not be recovered, is premised on the argument that the "wholesale sector reaped significant profits gained through MISO Day 2."[290] OTP noted that 40 percent of the Schedule 16 and 17 costs were allocated to wholesale asset-based and non-asset based margins.[291] Only the portion of Schedule 16 and 17 costs allocated to retail were deferred for recovery in retail rates. The methodology used by OTP for allocating MISO costs has been reviewed by the Department in a number of

[282] *Id.* at 78, Brause.
[283] *Id.* at 79. The volumetric allocator is discussed in detail earlier in the discussion of non-asset based margins.
[284] Department Reply at 24.
[285] See Tr. Vol. 5 at 85-86 (Lusti Testimony).
[286] Tr. Vol. 5 at 85-86 (Lusti Testimony)(noting that rates in between rate cases are assumed to be reasonable unless shown otherwise).
[287] *Id*. *ITMO Otter Tail Power Company's Report on a Call to its Ethics Hotline*, Docket No. E-017/M-04-1751 ("*Hotline Complaint Docket*").
[288] *See* Department's May 23, 2005 comments in *Hotline Complaint Docket*.
[289] *Hotline Complaint Docket*, at 2-3 (Commission Order Requiring Further Filings issued March 10, 2006).
[290] Ex. 98, Campbell Surrebuttal at 4.
[291] Tr. V. 2 at 93 (Beithon).

dockets without challenge, most recently in Docket E017/M-05-284, and no challenge to that methodology has been raised in this proceeding.

VI. INCENTIVE COMPENSATION.

218. OTP proposed that its annual incentive compensation be based on a 5-year average payout level, subject to a cap based on 25% of the individual employee's base compensation.[292] The Department opposed the Company's proposal, initially recommending that: (i) annual incentive compensation be adjusted to remove the results of all asset based margins and ten percent of non-asset based margins; and (ii) a refund mechanism be adopted. The Department also recommended that a 25% cap be applied to incentive compensation paid to the Company's employees who conduct purchases and sales of wholesale power.[293]

219. The OAG initially recommended that incentive compensation be based on 2006 levels and later joined in the Department's position. The Department noted calculation errors in the compensation calculations, which were corrected by OTP. OTP also agreed to expand the 25% cap to personnel engaged in wholesale transactions.

A. Incentive Compensation Levels.

220. The OTP test year revenue requirement includes an annual incentive compensation amount based on a five-year-average payout level for the OTP Key Performance Plan ("KPP") and the OTP Management Incentive Plan ("MIP") for the years 2002 through 2006. OTP Ex. 25 at 8 (Kangas Direct). The Department expressed several concerns relative to KPP and MIP Incentive Compensation

221. A 2005 Towers-Perrin study showed that the OTP's total cash compensation was 4% below the market rate for a broad range of non-executive positions.[294] A 2007 Towers-Perrin study showed that total cash compensation of Company executive positions was 21% below the market median.[295] OTP relied on this information to assert that the annual incentive compensation proposal, with the cap based on 25% of each employee's base salary, was reasonable. OTP maintained there was no evidence that its approach would lead to inclusion of excessive levels of compensation costs in rates.

222. OTP maintained that its compensation proposal was needed to provide adequate compensation in order to attract, motivate, and retain talented employees. OTP maintained that this is needed to provide high quality service to customers. To obtain such employees, OTP asserted that it must offer a competitive total compensation package.[296] OTP maintained that under-funding its compensation packages would impede the OTP's ability to attract, motivate and retain employees.[297] OTP described its annual incentive compensation plan is well balanced and consistent with incentive compensation plans that have been approved by the Commission.[298]

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[292] Ex. 26, Wasberg Rebuttal at 3.
[293] Ex. 100, Lusti Rebuttal at 5-7.
[294] Ex. 25, Wasberg (Adopted) Direct at 3.
[295] *Id.* at 4.
[296] *Id.* at 5.
[297] *Id.* at 6.
[298] *Id.* at 8.

B. The Department's Proposal.

223. OTP and the Department agreed on the overall method to include the effect of asset-based wholesale revenues; however, they differed on the amount to be credited to the base rate revenue requirement.[299] The Department recommended that all asset-based wholesale margins and ten percent of non-asset based wholesale margins be removed from the incentive compensation calculation. These amounts would be deducted from the basis for calculation of annual incentive compensation through a pro forma calculation.[300] That recommendation was based on the belief that this case would fundamentally change the manner in which the Company's earnings were calculated for determining the financial elements of its annual incentive compensation payments.

1. Asset Based Margins.

224. The Department recommendation is based on the belief that inclusion of asset based margins in regulated rates (on a going forward basis after this rate case) will represent a fundamental change.[301] OTP maintains that the Department's position is not correct in two respects. First, OTP has previously included all its asset based margins in its regulated earnings and in its calculations of earnings under its annual incentive compensation plans.[302] Second, the Department's calculation is inconsistent with the Department's own recommendation to preserve the current approach to asset based margins, under which both asset based revenues and costs are included in the determination of the base rate revenue requirement.[303]

225. OTP has consistently included asset-based margins in its regulated income, including all years from 2002 through 2007.[304] The Department acknowledged that there was no basis to dispute OTP's position that it had consistently included all asset-based margins in its determinations of earnings in 2002 through 2007.[305] The Department also acknowledged that the continuation of this practice after this rate case eliminated the basis to believe that any material change would occur.[306] OTP maintained that the Department's calculation relied on a mistaken belief that only the 1987 level of asset based margins ($739,000) had been included in determining earnings of OTP (for both reporting and incentive compensation calculations).[307]

2. Implicit Assumptions Regarding OTP's Financials.

226. OTP maintained that the Department's pro forma calculation necessarily rests on the unstated premise that the Company's management would have allowed very substantial reductions in its ROE from 2002 through 2006 without taking action to correct that situation.[308] OTP asserts that it would not have allowed such a substantial reduction in ROE to go uncorrected for any substantial period of time, and it would have sought a general rate increase but for the presence of earnings from wholesale margins.[309]

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[299] Department Brief, at 32..
[300] Ex. 99, Lusti Direct at 21.
[301] Ex. 26, Wasberg Rebuttal at 4.
[302] *Id.*
[303] *Id.*
[304] Ex. 10, Brause Rebuttal at 4.
[305] Tr. V. 5 at 73-78.
[306] *Id.*
[307] *Id.*
[308] *Id.* at 5.
[309] Ex. 9, Brause Direct at 7-8; Ex. 10, Brause Rebuttal at 4; Ex. 26, Wasberg Rebuttal at 7.

227. OTP maintained that the pro forma and actual ROEs for the Management Plan would have been as follows:[310]

Year	Actual ROE (per calculation in the Management incentive plan)	Pro forma ROE (calculated per Department parameters)
2002	12.69%	11.23%
2003	12.68%	10.07%
2004	12.16%	9.80%
2005	10.83%	7.47%
2006	10.49%	7.57%

The pro forma and actual ROEs for the Key Performance Award plan (KPA) plan would have been as follows:[311]

Year	Actual ROE (per calculation under the KPA incentive plan)	Pro forma ROE (per Department parameters)
2002	12.69%	11.23%
2003	13.03%	10.43%
2004	12.31%	9.94%
2005	11.10%	7.74%
2006	10.50%	7.59%

228. OTP maintained that changing a single very substantial historic event does not lead to a valid revision of historic events. OTP argued that corrective action would be taken on response to changes, making unreliable the results of the single revision.[312]

229. OTP also asserted that practical needs arising from the employer perspective also demonstrate that appropriate action would have been taken to prevent deterioration of earnings. OTP would not have afforded inadequate incentive compensation to its employees without taking appropriate action to restore adequate compensation levels. For example, OTP modified its incentive plans in 2007 to decrease the significance of financial performance in order to provide a

[310] Ex. 26, Wasberg Rebuttal at 6.
[311] *Id.* at 7.
[312] *Id.*

more reasonable opportunity for payout levels than had occurred in 2006, which reflected adverse financial performance.[313]

3. The Impact of the Department's ROE Recommendation on Pro Forma Calculations.

230. The Department's pro forma calculations, which were intended to provide results representative of the future, rest on assumed average ROEs of 9.00% to 9.15%.[314] In performing its pro forma calculations, the Department ignored the 10.71% ROE that it initially recommended, which was increased to 10.91%.[315] The assumed average ROEs of 9.00% to 9.15% do not provide reasonable estimates of the results of future operations.

C. Incentive Plan Recommendation.

231. OTP's proposal to limit recovery of annual incentive plan costs to the average of the Company's historical payout, along with a cap based on 25% of an employee's base compensation, provides appropriate protection to ratepayers.

D. Refund Mechanism.

232. OTP included $568,673 as incentive compensation in its test-year revenue requirement.[316] The Department recommends that incentive compensation that is included in base rates but is not paid to OTP's employees should be refunded to ratepayers. Each of OTP's incentive compensation plans contains the provision, "The Company, by written action of its President, reserves the right to amend or terminate this Plan at any time."[317] This provision allows OTP to stop incentive compensation payments to employees but continue to recover costs from ratepayers. The Company has not provided a logical rationale for why such a regulatory refund mechanism is unreasonable. OTP should be required to refund to ratepayers incentive compensation that is included in rates but not paid to employees. A refund mechanism for incentive compensation would be consistent with Commission precedent. The Commission in stated:

> In the original Order, the Commission expressed strong disapproval of the Company's retention of the right not to make incentive payments earned under the plan. The Commission continues to view this as an inappropriate transfer of risk from shareholders to ratepayers and as inconsistent with the test year concept on which rates are based. The Commission will therefore require the Company to record all earned but unpaid incentive compensation recoverable in rates under this Order for future return to the ratepayers. This will adequately protect ratepayers' interests and prevent erosion of the test year concept.[318]

233. This approach was followed in the *2005 Xcel Energy Rate Case* where the Commission ordered:

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313 *Id*. at 5, 8.
314 Tr. V. 5 at 82-83.
315 *Id*. at 83-84.
316 Ex. 20 at 55 (Beithon Direct).
317 Ex. 99 at 15 (Lusti Direct).
318 *ITMO Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota,* Docket No. E002/GR-92-1185, at 7-8 (Commission Order After Reconsideration issued January 14, 1994).

> The Commission concurs with, accepts, and adopts the ALJ's recommendation on this issue, which was to cap individual incentive compensation payments at 25% of an employee's base salary; to base total, company-wide incentive compensation on amounts actually paid out between 2002 and 2005; and to continue the tracking and refund mechanism established in the Company's 1992 rate case.[319]

234. The Commission's precedent on incentive compensation included in rates but not paid was followed in its *NSP Gas Rate 2007 Order*. The Order states:

> The Commission finds that the Company's proposed level of incentive compensation in this proceeding is reasonable and will approve it. The Commission also adopts the ALJ's finding and will require Xcel to refund amounts included in the test year for incentive compensation that were not actually paid.[320]

235. The Department continues to recommend that OTP be required to refund to its customers incentive compensation that is unpaid but included in rates. OTP maintained that a refund mechanism is unnecessary. OTP noted that the refund mechanism was applied only to Xcel Energy and has not been applied to other utilities in Minnesota.[321] OTP asserted that the refund mechanism was redundant and there was no basis for applying it to OTP's incentive compensation program.

236. Maintaining a tracking mechanism and refunding unpaid incentive compensation already included in rates is reasonable and not unduly burdensome.

VII. FAS 106 TRANSITION COSTS.

A. OPEB Transition Costs.

237. OTP requested recovery of the Minnesota portion of $748,200, which is the test year annual total Company amortization of the Post-Employment Benefits Other than Pensions transition obligation under FAS 106 ("FAS 106 Transition Costs"). The Company's request does not include any deferred amounts, as described by Commission's Order in Docket U-999/CI-92-96 ("Order Adopting Accounting Standard")[322] and the Commission's Order Granting Clarification.[323] The Company also made a $5,429,751 reduction to the Minnesota portion of total rate base to reflect the accumulated effect of the FAS 106 Transition Costs amortization.[324]

238. The Company's FAS 106 Transition Costs began with a $17,618,642 balance in 1993 that was subsequently adjusted to $14,964,000, with a 20-year amortization of $748,200 per year. The Department did not dispute the calculation of the $748,200 annual amount.[325]

239. The Department objects to the inclusion of the FAS 106 Transition Costs because: (i) the Department asserts that no amortization of any FAS 106 Transition Costs could occur unless the Company filed a rate case or other request to establish an amortization account for FAS 106

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[319] *2005 Xcel Energy Rate Case*, *supra*, Commission Order, at 18.
[320] *NSP Gas Rate 2007 Order*, at 13.
[321] Ex. 26, Wasberg Rebuttal at 9.
[322] Order Adopting Accounting Standard And Allowing Deferred Accounting, Docket No. U-999/CI-92-96, September 22, 1992 ("Order Adopting Accounting Standard").
[323] Order Denying Petition for Reconsideration, Granting in Part and Denying in Part Petitions for Clarification, Docket No. U-999/CI-92-96, November 2, 1992 ("Order Granting Clarification").
[324] Ex. 36, Brutlag Rebuttal at 30; Tr. V. 5 at 35-36.
[325] Tr. V. 5 at 28-29.

Transition Costs within in three years of the Order Adopting Accounting Standard; and (ii) the Company's FAS 106 Transition Costs were recorded in 1993.[326]

240. OTP maintains that if the Department is correct in the contention that OTP Company had no right to establish an amortization account for the FAS 106 Transition Costs, there should be no reduction to rate base as a result of the amortization of FAS 106 Transition Costs. That reduction amounts to $5,429.751. The Department does not dispute this relationship and conclusion.[327] The net result of disallowing the Minnesota portion of the $748,200 annual amortization and increasing rate base by $5,429,751 (which is the Minnesota portion of total rate base) would be an *increase* in the revenue requirement.[328]

241. The Order Adopting Accounting Standard distinguished between: (i) the basic amortization of FAS 106 Transition Costs; and (ii) the possibility of deferred accounting for 3 years of the amortization of those costs. OTP maintains that the order allowed, but did not require, deferred accounting of FAS 106 transition costs for three years.[329]

242. OTP maintains that amortization differs from deferred accounting. "Amortization" is defined in Uniform System of Accounts as follows:

> Amortization means the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. (18 C.F.R. Part 101 definitions.)

OTP contrasts this with deferred accounting, which is a regulatory construct under which a cost is accumulated for the period of the deferral for later recognition and recovery. Typically, deferred accounting involves accumulation of an annual expense for a period of time (into a regulatory asset account) for subsequent recovery over a reasonable period (amortization).[330]

243. OTP relies on the Commission's *Order Adopting Accounting Standards* recognizing a distinction between amortization and deferred accounting, reading in part:

> The Commission will therefore adopt SFAS 106 accrual accounting for Minnesota utility accounting and ratemaking purposes, subject to Commission review for prudence and reasonableness of the benefit programs and all calculations in future rate cases. The treatment of the transition obligation, including the proper amortization period assigned, and the propriety of funding the OPEB obligation will be decided in each rate case, on a case by case basis.
>
> <u>IV. Implementation of SFAS 106.</u>
>
> As discussed previously, the change from pay-as-you-go accounting to the accrual method for OPEBs may raise utility revenue requirements. If utilities were required to recognize the difference at once, the accounting change could force many utilities to file general rate cases in order to adjust their revenue requirements. *The Commission will therefore allow utilities to defer the increased cost created by the change to SFAS accounting.* The Commission will limit the time for *such deferred*

[326] Ex. 89, Johnson Direct at 21.
[327] Tr. V. 5 at 35-36.
[328] Ex. 36, Brutlag Rebuttal at 24.
[329] *Id*. at 25.
[330] *Id*.

> *accounting* for each utility to a period of three years beginning January 1, 1993, or until the issue date of the Order which sets final rates following a general rate case, whichever occurs first.[331]

244. OTP maintained that the first paragraph of the quote addressed the treatment of the basic amortization of FAS 106 Transition Costs. The second paragraph of the quote addressed the possibility of deferral of three years of the annual amortization. OTP argues that the purpose of the three-year deferral period was to avoid the potential of several utilities immediately filing rate cases, not to limit to three years recovery of FAS 106 Transition Costs (which could be up to 30 years).[332]

245. The Commission clarified its intentions in regards to possible deferral of three years of the amortization in its subsequent Order Granting Clarification, which states:

> The Commission will clarify its September 22, 1992 Order to identify specifically the treatment of deferred accounts beyond the three year period beginning January 1, 1993. If no rate case is commenced within that three year period, a utility will not be allowed recovery of the deferred amount.[333]

Ordering Clause 5 contains the same provisions and is also limited in scope to the "deferred amount" and reads in part:

> Deferred accounting will be allowed for each utility for three years beginning January 1, 1993. If no rate case is commenced within that three year period, a utility will not be allowed recovery of the *deferred amount.* If a rate case is filed within the three years, the utility will be allowed to continue deferring OPEB expenses until a final Order is issued in the rate case.[334]

246. OTP notes that the Commission has recognized that FAS 106 Transition Costs are an allowable cost of service, and it has permitted other utilities to recover these costs.[335] OTP asserted that the approval obtained by some utilities for amortization in matters filed before the *Order Adopting Accounting Standards* shows that the there is no rigid application of the subsequently adopted three-year limitation. OTP cites the *1992 Northern States Power Rate Case*, where the Commission stated:

> In the FAS 106 situation, the Commission has always found that the payment of Post-Employment Benefits Other than Pensions is a cost of service. A change in utility accounting, which results in a transition obligation, does not mean that these costs should be disallowed. (Emphasis added.)[336]

247. OTP also cited the Commission 's orders allowing recovery of FAS 106 Transition Costs in general rate cases, *Application of Peoples Natural Gas,* Docket No. G-011/GR-92-132,

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[331] *ITMO the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106*, Order Adopting Accounting Standard and Allowing Deferred Accounting, at 6, Docket No. U-999/CI-92-96 (Sept. 22, 1992)(*Order Adopting Accounting Standards*)(emphasis added).
[332] Ex. 36, Brutlag Rebuttal at 27.
[333] Order Granting Clarification at 6 (emphasis added).
[334] *Id*. at 8.
[335] Ex. 36, Brutlag Rebuttal at 24; s*ee, e.g.*, *Application of Northern States Power Company*, G-002/GR-92-1185; *Application of Peoples Natural Gas,* Docket No. G-011/GR-92-132; and *Application of Minnegasco*, Docket No. G-008/GR-92-400.
[336] Order After Reconsideration, Docket No. E-002/GR-92-1185 (January 14, 1994).

Findings of Fact, Conclusions of Law, and Order , February 22, 1993, at 22; and *Application of Minnegasco*, Docket No. G-008/GR-92-400, Order After Reconsideration, July 19, 1993 at 9. OTP has cited no cases supporting allowing these costs after the three year period identified in the Commission's Orders.

1. Recording Of FAS 106 Transition Costs.

248. All the cases cited by OTP were decided before the *Order Adopting Accounting Standards*. OTP maintains that the Commission's adoption of FAS 106 for both accounting and ratemaking purposes authorized up to a 30-year amortization period. OTP notes that other utilities continue to recover their FAS 106 Transition Costs, which arose at the same time as the Company's FAS 106 Transition Costs.[337]

249. The Department maintains that OTP's position is correct only if the FAS 106 Transition Costs are initially appropriately included in rate base. The Department contends that, for ratemaking purposes, this rate case is the first time the Commission has had an opportunity to decide whether OTP's transition obligation should be appropriately included in OTP's rates. Since OTP has not filed for deferred accounting with the Commission, the Department contends that the transition obligation amount is not allowable in OTP's rate base. The Department contends that utilities that decide to make such changes between rate cases without Commission approval are always at risk for nonrecovery of costs in their next rate case proceeding.[338] Under the Department's approach there would not be a shift to increase the rate base by $5,429,751 as OTP claims, but rather a reduction to rate base by the remaining amount of the unauthorized, unamortized transition obligation.[339]

2. Effect on Rate Base.

250. OTP maintains that disallowance of its amortization of FAS 106 Transition Costs (at $748,200 per year for total Company) would result in a $5,429,751 increase to the Minnesota share of rate base. This increase in rate base would occur because the amortization of FAS 106 Transition Costs has led to a credit to rate base in the amount of the cash difference between the FAS 106 Transition Costs under the accrual method and actual cash paid out.[340]

251. OTP's contention relies on the deferred costs being allowable, despite the absence of approval of these costs by the Commission under the terms of the Commission's *Order Adopting Accounting Standards.* OTP argues that, if the FAS 106 Transition Costs are not allowed as part of FAS 106 costs, the rate base would need to be trued-up to match this change. The cumulative amount of the amortization of the transition obligation through 2006 is $10,873,200 (with a Minnesota share of $5,429,751).[341] Therefore, rate base would need to be increased by $5,429,751, Minnesota's share of the cumulative amortization.

252. The Commission's *Order Adopting Accounting Standards* clearly limited approval of the costs at issue to a period of three years or the next general rate case, whichever came first. While OTP notes the language applied to the deferred costs, the Commission also stated that amortization needed approval. Clearly that approval was intended to be obtained in a timely

[337] Ex. 36, Brutlag Rebuttal at 28-29.
[338] Department Reply at 37.
[339] *Id*. at 38.
[340] Ex. 36, Brutlag Rebuttal at 24.
[341] *Id*. at 30.

fashion, not over a decade after being initiated. The costs are not allowable under the Commission's orders, and no increase to the rate base is appropriate.

VIII. PENSION, OPEB AND MEDICAL EXPENSES.

253. The Company proposed test year costs of $19,277,539 for Pensions, OPEBs, and Medical/Dental (collectively "Benefit Costs"), which was $414,984 *below* the 2006 actual levels of $19,692,523.[342] The Company proposed that:

(i) the test year expense levels for Pension and OPEB expenses be based on the actuarial studies of determining 2007 costs; and

(ii) the test year expense levels for Medical/Dental be based on actual data from January 2007 through July 2007, with the remainder of 2007 projected.

Overall, the Company's Benefit Costs have increased significantly from 2003 to 2007:[343]

Year	Total Amount	Change ($$)	Change (%)
2003	$14,675,355		
2004	$16,318,622	$1,643,267	11.2%
2005	$18,356,668	$2,038,046	12.5%
2006	$19,692,523	$1,335,895	7.3%
2007 (est.)	$19,277,539	($414,984)	(2.1%)

1. The Company's Projection and Actuarial Studies.

254. The Company used: (i) the actuarial determination of Pensions and OPEBs for 2007 that was prepared by Mercer Human Resource Consulting, Inc. ("Mercer"); and (ii) the actual and projected Medical/Dental expenses for 2007.[344] The Department reviewed the Mercer actuarial studies and did not dispute the accuracy or reasonableness of the Mercer studies.[345] The Department did not dispute the accuracy of the Company's projection of Medical/Dental expenses for 2007.

255. Mercer performs annual analyses of the Company's Pension and OPEB expenses. Annual actuarial analyses of Pension and OPEB obligations are performed to satisfy legal requirements arising from several sources, including: (i) the Employee Retirement Income Security Act; (ii) the Pension Benefits Guarantee Corporation; (iii) the Internal Revenue Service; and (iv) the Securities Exchange Commission.[346]

[342] Ex. 26, Wasberg Rebuttal at 10, 12.
[343] *Id*. at 11-12.
[344] *Id*. at 10.
[345] Tr. V. 5 at 27-28.
[346] Ex. 26, Wasberg Rebuttal at 14-15.

256. Mercer's estimate of $4,232,101 for 2007 Pension Expenses that the Company has proposed are based on FAS 87 expenses for 2007 and are $1,200,861 (22%) *lower than* actual FAS 87 expenses for 2006.[347] The Mercer estimate reflected a number of specific factors, which are appropriate for calculation of 2007 pension expenses and are consistent with FAS 87.

257. The Mercer estimate is based on the Company's demographics and its related business environment. These demographics and business environment factors include: (i) an updating of mortality tables in 2005; (ii) cash funding of approximately $4 million in each of 2005 and 2006; (iii) the current interest rate environment; (iv) recent legislation, including the Pension Protection Act of 2006; (iv) the soft freeze of the Company pension plan that occurred in 2006; and (v) the Company's current union labor agreement.[348] OTP maintains that these factors demonstrate why a 5-year simple average is an inappropriate and inaccurate basis to estimate Pension expenses.

258. Mercer's estimate of $3,321,412 for OPEB expenses that the Company has proposed are based on FAS 106 expense levels for 2007 and are $186,056 (5.9%) higher than actual FAS 106 expenses for 2006.[349] The actuarial model that Mercer used to calculate the FAS 106 OPEB expense reflects changes in demographics and business environment.

259. Mercer's actuarial calculations have changed to reflect: (i) annual review of discount rates and trends in medical expenses; (ii) new demographic information such as the relevance of marital status in actuarial calculations, which occurred in 2003; (iii) modification of the turnover rate and the updated mortality tables, which occurred in 2005; (iv) Company policy changes, like the increased cap on Coyote Station employees, which was implemented in 2003; and (v) legislative changes, such as the implementation of the Medicare Prescription Drug Improvement Act of 2003, which introduced the Medicare Part D subsidy (that caused a decrease in OPEB expenses in 2006).[350] OTP maintains that these are significant factors which demonstrate that a 5-year simple average is an inappropriate and inaccurate basis to estimate OPEB expenses.

260. OTP based its proposed Medical/Dental expenses on actual claims (expense) data through June 2007, trended to the end of 2007.[351] Medical/Dental expenses for 2003-2006 are as follows:

Year	Expense	Change from Prior Year ($)	Change from Prior Year (%)
2003	$8,666,479		
2004	$9,741,825	$1,075,346	12.4%
2005	$9,448,573	($293,252)	(3.01%)
2006	$11,124,205	$1,675,632	17.7%
2007 (est.)	$11,724,026	$599,821	5.4%

[347] *Id*. at 16.
[348] *Id*. at 17-18.
[349] *Id*. at 19.
[350] *Id*. at 20.
[351] *Id*. at 15.

OTP noted that only 2005 showed a slight $293,252 decline (3%) from the prior year.[352] In this context, the Company's estimate of a modest increase in 2007 was well founded. The Department did not identify any inaccuracy in OTP's estimates.

2. The Department's Recommendations.

261. The Department recommended Benefit Costs of $17,664,141, based on a 5-year simple average of data for 2003 through 2007.[353] The Department recommendation was $1,613,398 below the Company's proposal[354] and $2,028,382 below the actual 2006 levels ([$19,692,523 actual 2006] - [$17,664,141 Department recommendation]). The Department recommendation would substantially change expense levels for each of the elements of Benefit Costs: (i) *decreasing* Medical/Dental expenses by $1,583,004; (ii) *decreasing* Pension expenses by $799,534; and (iii) *increasing* OPEBs by $769,141.[355]

262. The Department's argument is premised on two claims: (i) that costs have historically fluctuated, which makes averaging a better approach; and (ii) that the Commission took a similar approach to averaging in the *2003 IPL Rate Case*.[356]

263. OTP maintains that the changes observed in Benefit Costs are not simple random fluctuations, but rather are the result of shifts in legislative and demographic factors that will have ongoing effects that would be ignored by the use of simple average data.

264. OTP contends that the Mercer studies of Pension and OPEB expenses reflect both the most current information and fundamental changes. The differences shown from year to year, OTP asserts, reflect a basic pattern regarding these fundamental changes. OTP asserts that none of these variations justify the use of simple averaging in place of more detailed studies. This would result, in OTP's opinion, in masking and distorting such fundamental changes. OTP argues that the use of averaging relies on an implicit assumption that no fundamental changes have occurred.

265. OTB notes that pension costs have also increased significantly from 2002 through 2007 as follows:[357]

[352] *Id*. at 16.
[353] Ex. 89, Johnson Direct at 18.
[354] *Id*.
[355] Ex. 26, Wasberg Rebuttal at 11.
[356] *In the Matter of the Petition by Interstate Power Company to Increase Electric Rates,* Docket No. E001/GR-03-767 ("*2003 IPL Rate Case*").
[357] Ex. 26, Wasberg Rebuttal at 17.

Year	Amount	Change from Prior Year ($)	Change from Prior Year (%)
2003	$1,434,687		
2004	$1,875,126	$440,439	30.7%
2005	$4,187,960	$2,312,834	123.3%
2006	$5,432,962	$1,245,002	29.7%
2007	$4,232,101	($1,200,861)	(22.1%)

266. OTP asserts that the changes between 2003 and 2007 show a significant upward trend of Pension costs, with only the conservative projection for 2007 showing a $1,200,861 (22%) decline from the prior year.

267. The Department has proposed a Pension expense of $3,432,567, which is a further reduction of $799,534[358] from the Company's proposed Pension expense. The effect is also a $2,000,395 (37%) reduction from the actual 2006 level.[359] Using a five-year average of Pension expense is a backward-looking model that implicitly assumes no fundamental trends or changes, and which does not properly reflect new information. The Department provided no evidence or analysis to support the preference for an arbitrary averaging that includes clearly non-representative data, such as the very low Pension expense levels of 2003 and 2004, in place of the results of actuarial studies.

268. OPEB expenses have decreased since 2003, as follows:[360]

Year	Amount	Change from Prior Year ($)	Change from Prior Year (%)
2003	$4,574,189		
2004	$4,701,671	$127,482	2.8%
2005	$4,720,135	$18,464	0.39%
2006	$3,135,356	($1,584,779)	(33.6%)
2007	$3,321,412	$186,056	5.9%

269. In contrast to the foregoing data, the Department recommendation is to *increase* the 2007 estimate by $769,141[361] with the result being OPEB costs of $4,090,553.[362] This is also a $955,197 (30%) increase from the actual 2006 level.[363]

[358] Ex. 89, Johnson Direct at 19.
[359] Ex. 26, Wasberg Rebuttal at 17; [$5,432,962 - $3,432,567 = $2,000,395].
[360] *Id*. at 19.

270. The Department provided no analysis of OPEB expenses[364] and no criticisms of the Mercer analysis.[365] A review of the Department testimony shows no assertion of inaccuracies in the Company's determination of 2007 Medical/Dental expenses. The Department relied on OTP's 2007 data as part of its 2003-2007 five-year average.[366]

271. The Department's approach was to determine a reasonable level of expense attributable to Minnesota ratepayers that would be applicable over all of the years between the present and OTP's next rate case. Department noted that the Commission adopted the averaging approach relative to pension expense for Interstate Power & Light Co. ("IPL") in its April 5, 2004 Order.[367] The Commission ordered the levelization of IPL's pension and other post-employment benefit expenses in its next general rate case. Rather than adopt a single-year pension expense based on an actuarial study, the Commission adopted a five-year average, stating:

> Levelizing is standard ratemaking treatment of anomalies in test year expenses, and the possibility that the timing of the Company's next rate case may work to its disadvantage in regard to this one test year expense does not justify abandoning normal test year procedures for dollar for dollar recovery.[368]

272. If the Commissioner chooses to use levelizing in this proceeding, subtracting the average amount from OTP's proposed $19,277,539 results in a decrease of $1,613,398 in the test year amount.[369]

3. Recent Commission Decisions.

273. In the *2005 CenterPoint Energy Rate Case*,[370] the ALJ recommended acceptance of the Department position, but the Commission rejected the ALJ recommendation, saying:

> The Commission believes that *the best predictor of test-year pension expenses should be used.* In this case, the pension expenses proposed by CenterPoint were actuarially determined …, using CenterPoint's participant demographics and actuarial assumptions consistent with those used by its parent, CPE. The pension costs were computed following the principles required by Financial Accounting Standards ("FAS") no. 87, "employers' accounting for pensions."[371]

274. As in the *2005 CenterPoint Energy Rate Case*, OTP's proposal relied upon actuarial studies (which are forward looking and reflect known facts). As in the *2005 CenterPoint Energy Rate Case*, the Department did not challenge the accuracy of the actuarial data. Applying the recent Commission decisions on this issue to the facts present here, OTP's methodology and

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361 Ex. 89, Johnson Direct at 19.
362 *Id*. MAJ-8.
363 As calculated by OTP: $4,090,553 - $3,135,356 = $955,197.
364 Ex. 26, Wasberg Rebuttal at 19.
365 *Id*. at 20; Tr. V. 5 at 27-28.
366 Ex. 89, Johnson Direct MJA-8, Line 6.
367 Ex. 89, Johnson Direct at 18 (citing *IPL 2003 Rate Case* Commission Order) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=1729688).
368 *2003 IPL Rate Case,* Commission Order, at 24-25.
369 Ex. 106, Johnson Hearing Statement.
370 *In the Matter of the Application of CenterPoint Energy Minnesota Gas, a Division of CenterPoint Energy Resources Corp. for Authority to Increase Natural Gas Rates in Minnesota,* Docket G-0008/GR-05-1380 ("*2005 CenterPoint Energy Rate Case*").
371 *2005 CenterPoint Energy Rate Case,* at 19 (Commission Findings of Fact, Conclusions of Law, and Order issued November 2, 2006) (emphasis added).

proposed test year costs should be adopted for the determination of the revenue deficiency to be addressed in this proceeding

IX. CORPORATE COST ALLOCATIONS.

A. OTP's Proposed General Allocator.

275. The only corporate cost allocations issue identified by the Department in prefiled testimony was whether OTP's alternative general allocator should be approved or whether OTP should be required to use the default general allocator otherwise required by the Commission's Orders in Docket No. 1008. In its Initial Brief, the OAG questioned the accuracy of OTP's cost allocation methodologies, challenged how the 25 percent cap on incentive compensation was calculated, challenged the recovery of legal costs, and requested that a workgroup be established to continue the review of OTP's cost allocation methodologies.

276. OTP is an operating division of Otter Tail Corporation. Otter Tail Corporation also owns a number of unregulated businesses. As a result, OTP sought to allocate certain costs from Otter Tail Corporation to OTP. OTP contended that it followed the Commission Orders in Docket 1008, which established a four-part hierarchical methodology that operates as follows:

1) Tariffed rates shall be used for tariffed services provided to nonregulated activity.

2) Costs shall be directly assigned whenever possible.

3) If costs cannot be directly assigned, they shall be allocated based on an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.

4) When neither direct nor indirect cost causation can be found, the costs are to be allocated using a general allocator.[372]

The Commission also adopted a default general allocator that uses the ratio of all expenses directly assigned or attributed to regulated and unregulated activities, excluding the cost of fuel, gas, purchased power, and the cost of goods sold.[373]

277. In the Docket 1008 Order, the Commission recognized that the cost allocation should be sufficiently flexible to reflect differences between utilities, and differences in the characteristics of the unregulated entities:

> The Commission understands that utilities differ in many essential respects, including their participation in affiliated operations. The Commission believes that the hierarchical principles offer sufficient flexibility for each utility to develop appropriate allocation methodologies based on the principles.[374]

278. The Commission's subsequent *Order Closing Docket* reaffirmed that utilities are allowed to deviate from the default approach in future rate cases, subject to the utility showing that:

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[372] *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Order Setting Filing Requirement, Docket No. G,E999/CI-90-1008 at 4 (September 28, 1994) ("Docket 1008" or "Docket 1008 Order").
[373] *Id.* at 6.
[374] *Id.* at 5.

> … its cost allocation principles produce similar results as would allocations following the recommended cost allocation principles,
>
> * * *
>
> or the public interest is better served by another method.[375]

279. On the subject of allocation principles, the Commission's Docket 1008 Order, states in part:

> Should a utility wish to base its cost separations on different principles, the burden of proof would be on that utility to prove that its cost allocation principles arrive at fully allocated costs, free of any cross-subsidization. The utility would have to show that the goals of fully allocated costing, as expressed in this and other Orders, are fully realized. The utility would have the burden of demonstrating that it considered all of its costs and that they are allocated to share burdens and benefits equitably between the regulated and nonregulated operations.[376]

280. OTP proposes changing Commission's methodology with respect to the general allocator. Rather than use the default allocator of expenses, OTP uses a general allocator comprised of three equally weighted components of revenues, assets and labor dollars.[377]

281. Ms. Brutlag testified that because of the diverse business activities of OTP's unregulated affiliates, using expenses as the only allocator would not provide reasonable results. A substantial portion of labor costs for the utility is capitalized. In comparison, Otter Tail Corporation's diversified businesses capitalize almost none of their labor costs. The default allocator, which uses only expenses, does not reflect this circumstance. Otter Tail Corporation's business operating margins range from 0.8 percent to 16.4 percent of revenue. OTP maintains that this variation shows that expenses relative to revenues vary significantly.[378] Some of OTP's subsidiaries have significant assets, while others have few assets; some are high revenue, low margin businesses, while others are low revenues but high margins; and some are more labor intensive businesses. OTP contended that using the three components of revenues, assets, and labor, recognizes this diversity. OTP maintained that its proposed allocation formula made up of these three major components is expected to have less unnecessary volatility than simply using expenses for the allocation.[379]

282. In its last rate case, Xcel Energy used a general alternative with three factors that is the same as OTP's, except that it used employee count rather than labor dollars.[380] OTP used labor dollars instead of employee count because the information was reliable and easily obtained without additional administrative work.[381]

283. The 1008 Docket's default general allocator allocates $1,524,387 (28%) of corporate costs to OTP in the test year, while OTP's proposed general allocator would allocate $2,098,794 (38%) of corporate costs to OTP. The difference between these two methods is $574,407. The

[375] Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket, (March 1, 1995) ("Order Closing Docket").
[376] Docket 1008 Order at 6.
[377] Ex. 34, Brutlag Direct at 40.
[378] *Id*.
[379] Ex. 34, Brutlag Direct at 43-44.
[380] Ex. 38, Brutlag Rebuttal at 8.
[381] Ex. 35, Brutlag Direct at 41.

Department contends that this difference demonstrates that the two methods clearly do not provide similar results.[382]

284. The 1008 Docket default general allocator is computed using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities, excluding the cost of fuel, gas, purchased power, and the purchased cost of goods sold.[383] The Department contrasted the accepted allocator elements to OTP's proposed general allocator, which is comprised of only revenues, assets and labor.

285. The Department also noted that OTP's alternative increased the revenue requirement by $287,204.[384] The Department distinguished Xcel Energy's general allocator based on the fact that, for Xcel Energy, the alternative general allocator resulted in a lower revenue requirement.[385]

286. OTP asserted that whether OTP's general allocator shares costs equitably should not be determined based on which methodology assigns the least cost to OTP. OTP asserts that the appropriate standard is whether there is an equitable sharing of costs. OTP had 55 percent of the consolidated corporation's assets, 50 percent of the consolidated corporation's income before income taxes, and paid 30.5 percent of the corporate management costs.[386] Incorporating the default allocator into the allocation process would have allocated 29 percent of all corporate costs to OTP in 2006.[387]

287. The OAG maintained that if the Commission's requirement under Docket 1008 is that an allocator should produce similar results to the default allocator, then utilities should "just use the 1008 method."[388] The OAG also argued against each of the three components of the OTP General Allocator. The OAG opposed using assets because utilities are asset heavy, with 54 percent of the assets residing in the utility.[389] Reliance on labor cost was opposed because different companies have different labor intensity.[390] The OAG expressed concern about using revenue as a factor, since some business operations have higher profit margins than others.[391]

288. The OAG argued that OTP's methodology could lead to volatile results as unregulated businesses were acquired or sold.[392] OTP contended that volatility was more likely under the default general allocator than under its three component allocator. OTP maintained that its allocator is influenced differently by different types of businesses providing stability rather fluctuations.[393]

289. OTP bears the burden to show that its allocation methodology is in the public interest. OTP's General Allocator is reasonable and is consistent with the Commission's recognition that differences in non-regulated business activity justifies modifying the Docket No. 1008 methodology to reflect those differences. The approved general allocator used by Xcel Energy is virtually

[382] Ex. 91, Johnson Surrebuttal at 4.
[383] Ex. 91, Johnson Surrebuttal at 4.
[384] Ex. 89, Johnson Direct at 9.
[385] *Id.* at 11.
[386] Ex. 34, Brutlag Direct at 44.
[387] Ex. 36, Brutlag Rebuttal at 9. Ms. Brutlag's Rebuttal testimony, Ex. 36, states that 32 percent of corporate costs were allocated, but after making the necessary test year adjustments the actual allocation was 30.5 percent, as stated in Ms. Brutlag's Direct, Ex. 34 at 44.
[388] Tr. V. 4 at 175.
[389] Ex. 79, Lindell Direct at 16.
[390] *Id.* at 17.
[391] *Id.* at 18.
[392] Ex. 79, Lindell Direct at 18.
[393] Ex. 36, Brutlag Rebuttal at 11.

identical to the one used by OTP. The fact that 38 percent of the common costs and 30.5 percent of total corporate costs were allocated to the utility (when compared to its actual assets and revenues) demonstrates that the methodology provides equitable results. OTP's methodology satisfies the alternative standards (similarity or public interest) established by the Commission for the use of an alternative methodology.

B. OTP's Prior Financial Reporting.

290. The OAG alleged that that it had "confirmed that inaccurate financial reporting has been the norm for OTP in the past."[394] OTP contends that the basis for this claim is OTP's prior use of a different general allocator than was used in the test year. OTP pointed out that utilities are allowed to use a general allocator that is different from the default general allocator under that standards set out in the Commission's 1008 Docket Order. The propriety of OTP's general allocator was at issue in the *Hotline Complaint Docket*. In that matter, OTP noted that, using the general allocator in effect (prior to the Commission's provisional approval of the current general allocator), 37.4 percent of total corporate costs were allocated to OTP in 2006.[395] An allocation of 37.4 percent of the corporate costs, when the utility had 55 percent of the consolidated corporation's assets, and 50 percent of the consolidated corporation's income before income taxes, does not support the OAG's claim of "inaccurate financial reporting." The change of an allocator in response to a Commission proceeding does not, without more, support a claim that there has been "inaccurate financial reporting." No evidence has been introduced in this proceeding that OTP has inaccurately reported its financial information.

C. Whether Costs Have Been Properly Allocated To Unregulated Operations.

291. The OAG characterizes OTP's test year allocations as confusing and conflicting. The OAG noted that OTP identified $6,074,777 in test year corporate expenses for calculating its revenue requirement, while OTP's workpapers contained a figure of $6,270,868.

292. OTP relied on the information in Exhibit 52 as demonstrating that no problem exists with the allocation system. OTP notes that the test year adjustments were made in steps. First, the actual 2006 amount of corporate costs allocated to the utility was reduced to reflect the general allocator agreed to in the *Hotline* case. Second, two additional adjustments were made, one increasing corporate costs for a wage increase and the other decreasing corporate costs for the 25% individual bonus cap. The following table shows these steps.

2006 Corporate costs allocated before adjustments	7,184,242
Adjustment for general allocator agreed to in Hotline docket	(913,374)
Corporate costs only adjusted for general allocator	6,270,868
Wage increase	153,459
25% bonus cap	(349,541)

[394] OAG Brief at 48.
[395] Ex. 34, Brutlag Direct at 39-40.

Net of two additional adjustments	(196,082)
Corporate costs allocated to utility for test year	6,074,786 [396]

Line 3 in the above table is the $6,270,868 amount found in the work papers and relied upon by the OAG for its claim. Ms. Brutlag's Direct Testimony differed by $9 from the amount reflected in the last line of the above table. The $9 is apparently the result of a typographical error in Ms. Brutlag's Direct testimony where the 2006 Corporate costs allocated before adjustments were reported as $7,184,233 instead of $7,184,242.[397]

293. OTP has shown that its allocation system produced appropriate results.

D. Calculating the 25 Percent Cap on Incentive Compensation.

294. The OAG asserts that OTP should have allocated officer bonuses first and than applied the 25 percent cap. OTP applied the 25 percent cap and than allocated the bonuses. According to the OAG, OTP's method increased the allocation by $10,321. This issue was raised for the first time in its Initial Brief.

295. OTP contends that, whether the cap is applied before or after the allocation, the results should be the same. Consider the following hypothetical, which assumes that the amount allocated to OTP is equivalent to 30 percent, and that the 25 percent cap on bonuses equals $25,000, resulting in $75,000 being disallowed:

OAG Method	**OTP Method**
$200,000 salary	$200,000 salary
$100,000 bonus	$100,000 bonus
$300,000 total	$300,000 total
times .3 allocation	less $75,000 ($100,000 less $25,000 allowed)
$90,000	225,000
less 22,500 (.3 times the excess $75,000)	times .3
$67,500 costs to OTP	$67,500 costs to OTP

296. The results do not appear to change based on when the disallowance is calculated. The calculation can be run with different numbers. In the event that there is no differing impact, OTP's approach can be adopted.

[396] Ex. 52 at 4, is a copy of OTP's response to IR OAG-38. It shows the 2006 actual amount of corporate costs allocated to OTP ($7,184,242). Page 3 of Ex. 52 shows the 3 adjustments and shows the amount in the test year ($6,074,786). The workpaper that OAG Brief refers to – 2006 TY-09, page 3, shows the amount of $6,270,868 and is labeled "Total using revised Gen Alloc."
[397] Ex. 34, Brutlag Direct at 39.

E. OTP's Legal Costs.

297. The OAG claimed that two legal invoices provide "an example of improper allocations for the test year." [398] OTP noted that the invoices were legal expenses, not allocated expenses. The expenses were directly incurred by OTP, not OTC.[399] The allocation process is not relevant to this claim.

298. OTP had declined to provide its actual invoices based on the attorney client privilege. As agreed to at the evidentiary hearing,[400] OTP provided a trade secret summary of the purposes of the legal work and explained why the expenses were reasonable utility expenses.[401] The OAG did not identify a particular reason for disallowance of these expenses. The OAG maintained that the description of the expenses provided in the summary does not justify cost recovery.

299. OTP has demonstrated a sufficient basis for recovery of these direct expenses.

F. Proposed Workgroup to Evaluate OTP's Cost Allocations.

300. The OAG advocated creation of a work group to develop a new cost allocation manual for OTP. The OAG maintains that such an approach is needed due to the deficiencies that have been identified in this proceeding.[402]

301. OTP noted that the composition, goals, and timing of such a work group remain unclear. OTP also expressed concern that such a workgroup would delay implementation of new final rates, delay the resolution of this rate case outside of the established timeframe, and is generally not appropriate.

302. The Commission can address continuing questions regarding OTP's cost allocation practices through the Commission's investigative powers. There has not been a need demonstrated for establishing a workgroup to assess OTP's cost allocation practices, and that proposal should be denied.

X. E8760 ALLOCATOR.

303. OTP allocated energy costs using kWh sales for both jurisdictional cost of service study ("JCOSS") and class cost of service study ("CCOSS") purposes. Enbridge and the MCC advocated the use of an E8760 allocator, which allocates energy costs on a per kWh basis with adjustments by class weighting factors to reflect differences in class load patterns and hourly marginal energy cost.[403] In the absence of an E8760 allocator, Mr. Erickson created a "hybrid 8760" allocator.[404]

304. The name (E8760) reflects that there are 8760 hours in a year and that the different energy costs in each hour would be used in developing a different energy factor for each customer class. Xcel Energy used an E8760 allocator in its CCOSS in its most recent electric rate case,

[398] OAG Initial Brief, at 52.
[399] Tr. V. 6 at 18-19, Brutlag.
[400] *Id.* at 30-31.
[401] Ex. 140.
[402] OAG Initial Brief, at 54-55.
[403] Ex. 120, Ouanes Rebuttal at 5-6.
[404] Ex. 69, Erickson Direct at 15.

Docket No. E002/GR-05-1428.[405] For jurisdictional purposes, Xcel Energy continued to allocate costs using its previously approved E20 energy allocation methodology.[406] Similarly, while Minnesota Power developed an E8760 allocator for retail rate design purposes, in Docket No. E015/M-07-1430, Minnesota Power used total energy sales adjusted for losses for purposes of its jurisdictional allocator.[407] Dr. Ouanes supported the use of the E8760 methodology in OTP's next rate case, for CCOSS purposes, stating: "the E8760 allocation factor would more accurately reflect costs imposed on customer classes on OTP's system than the E1 and E2 [jurisdictional] allocation factors proposed by OTP."[408]

305. OTP proposed studying the implementation of an E8760 factor for use in its CCOSS, presenting the results of such a study and potentially recommending implementation of an E8760 allocator for use in its CCOSS in its next rate case.[409] OTP proposed this approach for the following reasons:

> Developing an E8760 factor for OTP's Minnesota loads will involve a large amount of study and work. I've discussed the issue with Xcel Energy, which is 10 times the size of Otter Tail, and they questioned whether it was worth the effort and expense for a utility of our size and with the characteristics of OTP. OTP's load research would need to be reviewed and appropriate samples designed as the existing load research wasn't designed for the development of the E8760. Changing samples means placing new metering and collecting data for an appropriate amount of time. This also involves testing the samples and potentially placing new load research meters, which requires a period to achieve, plus time to collect enough data, and more than a year's worth of data, to complete that. OTP is also very unique in the industry in that its load is only 30 percent of the load in its own control area, or balancing authority, as the current term is. OTP would also have to review its production cost model and likely replace it as it is not designed to handle the demands in an E8760 process.[410]

306. In the absence of the detailed usage and cost information needed to develop an E8760 factor, Mr. Erickson created a different energy allocation factor using only limited information for Enbridge. Based on his "hybrid E8760 factor," Mr. Erickson proposed shifting $1,475,210 in costs from Minnesota to North Dakota and South Dakota.

307. The only load data used by Mr. Erickson was for Enbridge. OTP noted that Enbridge, while a large customer, accounts for only 20 percent of OTP's Minnesota load and likely less than 10 percent of OTP's system load. Mr. Erickson, in the absence of any actual load data for the three states, assumed that Minnesota customers have a higher load factor and off-peak usage than do customers in North Dakota and South Dakota.[411] Mr. Erickson testified that if Minnesota customers have a higher load factor and off-peak usage then Minnesota customers are being over

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[405] Ex. 71, Erickson Surrebuttal at 15 (contended that Minnesota Power developed an E8760 allocation factor to recover the costs for a single investment in 6 weeks with one man month of effort. OTP asserted that it was unfamiliar with Minnesota Power's work but concluded that the same would not be true for OTP's system.
[406] Ex. 22, Beithon Rebuttal at 12.
[407] *ITMO Minnesota Power's Petition for Approval to Implement Cost Recovery under its Boswell 3 Environmental Improvement Plan*, Docket No. E-015/M-07-1430 (Commission Order issued December 24, 2007)(citing Department Comments at 3, appended to the Commission's December 24, 2007 Order) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=4877798).
[408] Ex. 120, Ouanes Rebuttal at 7.
[409] Ex. 24, Beithon Surrebuttal at 4.
[410] Tr. V. 2 at 35-36, Beithon.
[411] Ex. 69, Erickson Direct at 14.

allocated energy costs.[412] Mr. Erickson also assumed that, once Enbridge's Minnesota load is removed, the remaining customers in the three states have comparable energy and demand.[413] Mr. Erickson provided no evidence to support his two assumptions.

308. OTP contended that customers in North Dakota and South Dakota are likely to have a better load and off peak usage than that of Minnesota customers. On this point, Mr. Beithon testified:

> Q. …[O]n page 4 of Mr. Erickson's surrebuttal, Enbridge's witness has a rate table, and why are the North Dakota and South Dakota rates shown by Mr. Erickson to be lower?
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> A. Those rates are from the EEI average, a rate survey for the period ended June 30, 2007. The comparison is the average price paid, not the actual rates paid. The average prices are lower in North and South Dakota because North and South Dakota customers use more controlled service rates for heating than Minnesota customers, so the average price paid per kilowatt-hour is lower than the average price paid by Minnesota customers.[414]

309. OTP argued that the wider controlled service rate use in North Dakota and South Dakota is inconsistent with an assumption that customers in the three states (excluding Enbridge) have comparable loads. Mr. Schedin testified that the demand (D1) and energy (E1) factors for Minnesota are comparable to the combined North Dakota and South Dakota D1 and E1 factors. This means that the D1 and E1 use in Minnesota (with Enbridge's load included) is comparable to the demand and energy for North Dakota and South Dakota combined.[415] OTP argued that this comparability demonstrates that Mr. Erickson's assumption is incorrect. This assumption, that Minnesota has a higher demand and better off peak usage than North Dakota and South Dakota, is a critical component of Mr. Erickson's E8760 adjustment methodology.

310. Mr. Schedin testified that while the differences in demand and energy between the states were not significantly different, the E8760 allocator would still be useful for class allocation purposes in the CCOSS stating: "that's where the E8760 allocator is most important, comparing the classes."[416]

311. Mr. Erickson did not use an E8760 methodology in making his adjustment. Mr. Erickson estimated Enbridge's hourly average marginal cost taken by its hourly load multiplied by OTP's hourly locational market prices (LMP). Mr. Erickson did not have hourly load information for any other customer, customer class or jurisdiction. Instead, used an average cost basis to substitute for that information. The purpose of the E8760 factor is to compare hourly load differences between different customer classes and, absent hourly load information for other classes, it is not possible to support the costs causation claims necessary for Mr. Erickson's financial adjustments. Enbridge's financial adjustment on a jurisdictional basis is unsupported.

312. The Department and OTP agreed that Mr. Erickson's approach did not provide useful results.[417]

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[412] *Id*. at 15.
[413] *Id.*
[414] Tr. V. 2 at 24, Beithon (emphasis added).
[415] Tr. V. 4 at 112-113.
[416] *Id.* at 113.
[417] Ex. 30, Parmesano Rebuttal at 13-14; and Ex. 120, Ouanes Rebuttal at 7.

313. Based on the foregoing findings, Enbridge's jurisdictional allocation adjustment should not be accepted. In addition, OTP should not be required to develop an E8760 allocator for its next rate case. OTP should be required to continue investigating whether the costs and benefits of an E8760 allocator justify developing such a methodology. If the Commission requires OTP to develop such a methodology, it should be limited to CCOSS development purposes.

XI. CLAIMED ADJUSTMENT FOR LOSSES.

314. Mr. Erickson proposed a new financial adjustment of $147,000, asserting that OTP had improperly allocated losses because: (1) OTP had not prepared a new loss study to match the MISO Day 2 market treatment, and (2) because Enbridge now takes service at 115 kV.[418]

315. OTP responded that it does not directly allocate losses. Rather, OTP uses losses in the calculation of energy factors, stated as a percentage. These energy factors are not used to recover losses. Mr. Beithon explained that an updated loss study would not have a material impact on the cost allocations between jurisdictions because a change in loss levels does not change the relationship between the allocation factors.[419] An updated loss study would uniformly increase or decrease each of the allocation factors by the same percentage. That would result in the allocation factors retaining their existing relationships and the resulting allocated costs would not change materially.

316. Enbridge's adjustment was based on the assumption that OTP had allocated losses at the same percentage for its pipeline load as was used in the 1986 rate case. At the time of the 1986 rate case, OTP owned the transformers used to serve its pipeline customers. Subsequently, Enbridge purchased the transformer from OTP. Because the transformer is now owned by Enbridge, the losses associated with the transformer are no longer treated as losses on OTP's system. OTP adjusted the losses to reflect Enbridge's ownership of its own transformer. The losses assigned to the pipeline group in OTP's prior rate case were reduced from 6 percent to 4.25 percent.[420] OTP has other pipeline customers besides Enbridge and, consequently, the losses associated with Enbridge were lower than 4.25. While Enbridge is not responsible for losses related to the transformer, it is responsible for its proportionate share of transmission losses. In the past, losses for 100 kV and above facilities were recovered through bilateral agreements, now they are recovered through MISO. The loss payment mechanism has changed under MISO for larger transmission facilities, but the payment for losses has not changed, and OTP still pays for the losses attributable to Enbridge. Enbridge should still be responsible for its proportionate share of losses.

317. Mr. Erickson's adjustment is based on limited information for the 20 percent of OTP's Minnesota load associated with Enbridge. Mr. Erickson assumed that a shift in costs related to losses away from Enbridge should be recovered from North Dakota and South Dakota customers. Mr. Erickson has provided no loss information for Minnesota, North Dakota and South Dakota to support his adjustment. He provided no analysis of how a change in losses would affect the allocation factors. No evidence was presented that a reduction in losses assigned to the pipeline customers would flow to other jurisdictions (rather than, for example, to other LGS customers).

318. For all of the forgoing reasons, Enbridge's proposed loss adjustment should be denied.

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[418] Ex. 72, Erickson Surrebuttal at 13-14.
[419] Tr. V. 2 at 26.
[420] Tr. V. 2 at 65, Beithon.

XII. D-1 ALLOCATOR.

319. Enbridge proposed a $457,566 adjustment to the D-1 allocation factor to reflect an error made by OTP in the treatment of interruptible loads. OTP agreed to the need for the adjustment but determined that there had been an error in the original calculation of the D-1 factor for Enbridge's load. When the correction to the original D-1 factor was made, the net adjustment became $261,210. Enbridge stated in its Initial Brief that: "To date, Enbridge has not been provided any work-papers to support Mr. Beithon's amendment, and we cannot, therefore, agree to the OTP adjustment."[421]

320. Mr. Beithon explained his adjustment to the D-1 factor in his surrebuttal testimony.[422] Enbridge provided no evidence that the adjustment made by Mr. Beithon is incorrect. Enbridge cross examined Mr. Beithon on the reasons for the adjustment, obtaining clarification of the need for the change.[423] OTP provided sufficient evidence to explain and support its adjustment.

XIII. PROPOSED FCA MATCHING ADJUSTMENT.

321. Mr. Erickson proposed a $529,613 revenue adjustment to remove a lag between the fuel costs included in the 2006 test year and later associated revenues received by OTP in 2007.

322. OTP described its fuel cost recovery as occurring through two mechanisms. A historical level of fuel costs is included in base rates. The base cost of fuel rate was determined outside of the rate case, in Docket No. E017/MR-07-1220. On a going-forward basis, variations in costs from the revenues provided using the base cost of fuel rate are recovered through the fuel clause adjustment (FCA). The FCA rate charged in any given month is determined by using the historical fuel costs from the preceding two months. Based on the fact that the FCA uses a rate based on a historic level of costs, Mr. Erickson concluded that there is a revenue lag that justifies imputing 2007 revenues to match the 2006 test year fuel costs.

323. The Commission-established FCA process uses historic costs to determine the rate, but OTP contends that there is no lag in cost recovery. For example, the FCA rate for February 2007 is applied to February 2007 sales for the purpose of recovering February 2007 costs. The February FCA rate is based on the cost of energy and sales for November and December 2006. No 2006 costs are recovered in February. February 2007 sales are the driver for the revenues, and those revenues are not related to the costs incurred in the 2006 test year. To the extent the February 2007 rate over- or under- recovers the actual February 2007 fuel costs, that difference is separately trued-up on an annual basis. The true-up is not, however, based on a comparison of the February 2007 revenues to the November and December 2006 sales.

324. Mr. Erickson's adjustment methodology does not reflect a "lag" in revenues. Mr. Erickson did not remove the revenues received in January, February and March 2006 and replace them with the revenues that were received in January, February and March 2007. OTP maintains that Mr. Erickson's adjustment is based on manipulations of the base cost of energy for 2006. The base cost of energy is not part of the rate case revenue requirement. The base cost of energy establishes a benchmark against which to determine the starting point for the FCA. If the benchmark is set too high, then the FCA in following months is reduced. If the benchmark is set too low, then the FCA in following months is higher.

[421] Enbridge Brief at 15.
[422] Ex. 24, Beithon Surrebuttal at 5.
[423] Tr. V. 2 at 73-74, Beithon.

325. OTP pointed out that the lack of correlation between the base cost of energy and Mr. Erickson's lag adjustment is demonstrated when Mr. Erickson's methodology is used to calculate a "lag" adjustment after the Department's AAA adjustment is made to the base cost of energy rate. The Department's adjustment reduces both fuel revenues and fuel expense by $683,983 and, consequently, has no impact on the revenue requirement.[424] That adjustment, however, reduces the base cost of energy to $0.025668. When that change in the base cost of energy is flowed through Mr. Erickson's methodology, his adjustment is reduced from $529,613 to $210,193. OTP maintained that a change in the base cost of energy, having no impact on the rate case revenue requirement, should not cause more than a 60 percent reduction in Mr. Erickson's FCA lag adjustment.

326. OTP contends that if this "lag" adjustment was appropriate, it would have been appropriate in every electric and natural gas rate case since the FCA and PGAs were implemented at the inception of regulation in the 1970s. Mr. Erickson asserted that the FCA lag was eliminated the *1994 Minnesota Power Rate Case*. OTP disputed the contention, noting that that there was no discussion of the adjustment in the Commission's decision in that matter. OTP pointed out that the alleged "lag" methodology has not been used in any of the approximately twelve rate cases that have been decided since the *1994 Minnesota Power Rate Case*.

327. Enbridge argues that OTP's position on this issue is inconsistent with its own Revenue Recognition Accounting.[425] This appears to be a reference to OTP's 2006 Annual Report in which there was a footnote stating that "Revenue is accrued for fuel and power costs incurred in excess of amounts recovered in base rates, but not yet billed through the fuel clause." Mr. Beithon explained that this is a financial reporting reference to OTP's FCA true-up mechanism.[426] The true-up mechanism annually adjusts revenues to match expenses. A number of factors can cause a mismatch between revenues and costs, but OTP maintains that none of those reasons are due to a lag.[427] In some years, OTP will recover additional revenues through the true-up process, while in others (including, OTP noted, the current year) it will be providing a refund.[428] OTP maintained that, under Enbridge's argument, OTP would currently be entitled to an increase in its revenue requirement.

328. Because OTP has a true-up mechanism that operates outside of base rates, any under- or over-collection in 2006 has already been trued-up. Based on the foregoing, Mr. Erickson's proposed FCA lag adjustment should not be adopted.

XIV. ECONOMIC DEVELOPMENT.

329. OTP requested that $330,000 in economic development expenses be included in revenue requirements.[429] OTP's proposed economic development expenses consist of $175,000 in labor costs, $20,000 in related expenses, a $35,000 loan pool loss provision, and a new $100,000 community matching-grant component.[430]

330. Over the past five years, OTP has typically spent about $250,000 annually on its Minnesota economic development program.[431] The difference between this historic level of

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424 Ex. 96, Campbell Direct at 43; and Ex. 23, Beithon Rebuttal at 19.
425 Enbridge Brief at 21.
426 Tr. V. 2 at 69-70, Beithon.
427 *Id.* at 70.
428 *Id.*
429 Ex. 34, Brutlag Direct at 46.
430 *Id.*
431 *Id.* at 46.

expenses and OTP's proposed expenses relates largely to OTP's proposal to add $100,000 for a community matching-grant component to its program. With that addition, OTP's Minnesota economic development program will be similar to its North Dakota Program.[432] OTP's North Dakota economic development program has been approved for rate recovery since 1989.[433]

331. The Commission has allowed economic development costs to be included in a utility's revenue requirement where such development programs are demonstrated to be cost effective. The Commission declined to require that each program be determined to be cost-effective on its own merits. Finding that both ratepayers and shareholders benefited from such programs, the Commission awarded 50 percent of the overall economic development costs for inclusion in rates.[434]

332. OTP noted that its service area includes a very sparsely populated region of Northwestern Minnesota, comprised of very small rural towns. Towns in OTP's service area have an average population of approximately 400.[435] Over one-half of the towns served by OTP have populations of fewer than 200 and several have populations under 100.[436] OTP serves only two municipalities in Minnesota with populations over 10,000: Fergus Falls (population - 13,949) and Bemidji (population - 13,074).[437]

333. OTP noted that many of the small towns it serves are experiencing population decline.[438] OTP maintained that a lack of job opportunities contributes to this decline. Migration is occurring from the smaller towns to larger communities in OTP's service territory. Migration is also occurring from within OTP's service territory to areas outside Otter Tail's service territory, such as the growing Fargo-Moorhead, St. Cloud and Twin Cities metro areas.[439]

334. OTP has had an active economic development program in place for the last several years. OTP partially credits the absence of any decline in total population across its service territory to these efforts. OTP noted that the population in Northwestern Minnesota is aging, however, and recent opportunities in areas such as the Fargo-Moorhead area are putting additional pressure on the populations of small towns in OTP's service area.[440] OTP contended that its service territory will be at risk for a decline in its total population if economic development assistance is discontinued.

335. OTP intends its economic development efforts to stabilize its communities by reducing intra-territory migrations and out-migrations.[441] No party disputed that OTP's economic development efforts have been successful in saving and creating jobs throughout its Minnesota service territory.

336. OTP's economic development efforts in 2006 included 44 projects throughout its Minnesota territory involving a wide range of business categories, including manufacturing,

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[432] *Id*.
[433] *Id*.
[434] *ITMO the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota*, E-002/GR-92-1185 at 47-48. (Commission Findings of Fact, Conclusions of Law, and Order issued September 29, 1993)(http://www.puc.state.mn.us/docs/orders/93-204.pdf).
[435] Ex. 34, Brutlag Direct at 50.
[436] *Id*.
[437] Ex. 6, MacFarlane Direct at 2.
[438] Ex. 34, Brutlag Direct at 50.
[439] *Id*. at 50; Ex. 36, Brutlag Rebuttal at 17.
[440] Ex. 59.
[441] Ex. 36, Brutlag Rebuttal at 16.

agricultural processing, retail, medical and nursing services, computers, groceries, and other businesses.[442] OTP credited those projects with saving 127 existing jobs and creating another 498 jobs in OTP's Minnesota service territory.[443]

337. OTP noted that when its customers change locations within OTP's territory, OTP incurs all the costs of service at the new location but does not avoid all the costs of service at the old location. This creates a duplication of costs of providing electric service.[444] The duplicated (also known as "sunk") costs include costs related to delivery facilities, costs of line personnel and other costs. In these instances of intra-territory migrations, OTP does not avoid any costs of service, including energy related costs or costs associated with transmission and generating capacity, as those costs are still incurred to serve the customer at the new location.[445]

338. OTP demonstrated that its economic development proposal is cost effective in mitigating the waste associated with intra-service territory migrations.[446] No party challenged OTP's demonstration of the cost-effectiveness of OTP's program in mitigating the waste associated with intra-service territory migrations.[447]

339. When OTP customers migrate to areas outside OTP's service territory (out-migration), OTP does not avoid all the costs of service of the departing customers.[448] Just as for intra-territory migrations, the sunk costs that are not avoided when customers out-migrate are those related to delivery facilities, line personnel, and other costs.[449]

340. A benefit/cost ratio of 1.00 or more indicates the proposed program to be cost effective.[450] The Department's original cost effectiveness analysis, performed for its direct testimony, showed a result of 0.91.[451] OTP pointed out that the Department had assumed that all costs of services would be avoided when a customer out-migrated.[452] The Department subsequently adjusted its cost-benefit analysis using available cost information for OTP transmission and generating capacity costs that demonstrated OTP's proposed economic development program to be cost effective, with a result of 1.19.[453] OTP also performed several sensitivity analyses, all of which were above 1.00.[454] No other party attempted to evaluate the program's cost effectiveness.

341. The Department continued to argue that none of the program's costs should be included in OTP's revenue requirements because it believed that updated capacity cost information relating to the Big Stone II project "may be large enough to make Otter Tail's economic development program not-cost-effective."[455] The Department contended that OTP did not adequately demonstrate that its economic development proposal is cost effective with respect to

[442] Ex. 37, Brutlag Rebuttal-non-public, Schedule 11.
[443] *Id*.
[444] Ex. 34, Brutlag Direct at 17.
[445] *Id*.
[446] *Id*.
[447] *See, e.g.*, Tr. V. 4 at 90-91.
[448] Ex. 36, Brutlag Rebuttal at 13-15.
[449] Ex. 34, Brutlag Direct at 17; Ex. 36, Brutlag Rebuttal at 15.
[450] Ex. 82, Davis Direct at 8.
[451] *Id*. at 8-10.
[452] Ex. 84, Davis Surrebuttal at 4.
[453] *Id*. at 7-8.
[454] Ex. 36, Brutlag Rebuttal at 15-17.
[455] Ex. 84, Davis Surrebuttal at 7-8.

out-migrations.[456] The OAG and AG Processing indicated their support for this position, but did not provide independent evidence or evaluations.[457]

342. The Department's argument relied on an assumption that out-migrations should be assessed in the same manner as conservation programs, for which a cost-benefit analysis would include savings associated with avoided transmission and generating capacity costs.[458] This argument was limited to an evaluation of the program with respect to out-migrations. The Department did not contest the cost-effectiveness of OTP's program with respect to intra-territory migrations.[459]

343. OTP has shown that equating out-migrations with conservation and including such costs in the cost-benefit analysis is inappropriate. Out-migrations do not reduce the need for capacity additions. The need for capacity additions is merely moved from one utility territory to another.[460] This is a clear difference from conservation programs, where the need for capacity is reduced by avoiding demand.

344. The OAG claimed that 50% of economic development costs were disallowed in OTP's last rate case and argued that 50% of OTP's current proposed economic development costs should be disallowed consistent with Commission precedent.[461] The OAG is incorrect that 50% of OTP's economic development costs were disallowed in its last rate case. No economic development costs were disallowed in that rate case.[462]

345. The OAG's and AG Processing's argument that 50% of OTP's economic development costs should be disallowed based on Commission precedent ignores the Commission direction that 100% of such costs should be allowed if a utility's economic development program is demonstrated to be cost effective.[463] As discussed above, OTP has demonstrated that its economic development program is cost effective and, therefore, 100% of the costs associated with that program should be allowed to be recovered in rates.

346. The OAG and AG Processing argued that Otter Tail Corporation's non-utility subsidiaries should share in the costs of OTP's proposed economic development program because they may benefit from such programs.[464] These arguments are contrary to the evidence contained in the record. By reviewing the economic development projects completed by OTP in 2006, it is clear that those efforts are directed to businesses in small towns within OTP's service territory, not to any Otter Tail Corporation non-utility subsidiary.[465] Only one non-utility subsidiary is located in OTP's service territory (Shoremaster in Fergus Falls), and seven of the eleven non-utility subsidiaries are not even located in Minnesota.[466] Furthermore, there is absolutely no reason to believe, and no evidence in the record to support, the argument that Otter Tail Corporation's non-utility subsidiaries would benefit from slowing intra-territory migrations within OTP's service territory and out-migrations from OTP's service territory. For these reasons no

[456] *Id*. at 5-6; Ex. 81, Davis Hearing Statement at 1.
[457] OAG Brief at 58-59; AG Processing Brief at 1-3.
[458] Ex. 84, Davis Surrebuttal at 6; Tr. V. 4 at 89.
[459] *See, e.g.*, Tr. V. 4 at 90-91.
[460] *Id*. at 100-101.
[461] OAG Brief at 58-59.
[462] April 27, 1987 Order in Docket No. E-017/GR-86-380 (there is no mention of economic development expenses).
[463] OTP Brief at 140-141.
[464] OAG Brief at 59; AG Processing Brief at 2.
[465] Ex. 37, Brutlag Rebuttal, non-public, at 16, Schedule 11.
[466] Ex. 57, Glahn Surrebuttal at 7.

amount of OTP's proposed economic development costs should be allocated to Otter tail Corporation's non-utility subsidiaries.

347. AG Processing argued that other agencies are involved in economic development and, therefore, OTP does not need to have an economic development program.[467] The fact that others are involved in economic development efforts does not change the legitimacy of OTP's request for rate recovery in this case. In all instances where the Commission has addressed economic development cost recovery, other state and regional agencies have been involved in economic development efforts along with the utility. OTP's program was designed to leverage other available economic development efforts. That is the fundamental nature of the loan pool concept and the community matching-grant concept, in which each requires participation by other economic development interests.[468] The labor component of OTP's program is largely spent coordinating economic development funds available from other agencies, as demonstrated by the 2006 projects discussed by Ms. Brutlag.[469] Representatives of other economic development agencies provided supportive public comments at the public hearings in this case, noting that OTP has been instrumental in coordinating successful economic development projects in the small rural towns served by OTP.

348. OTP has demonstrated its proposed economic development program to be cost effective in mitigating the harmful effects of intra-territory migrations and out-migration. All costs of that program are properly included in the Company's revenue requirements. The existence of other programs is not a basis for adjusting the allowable expenses of OTP's proposed economic development program.

XV. RATE CASE EXPENSES.

349. OTP proposed a three-year amortization of rate case expenses, at a rate of $486,822 per year (after accepting the Department's correction of an allocation factor).[470] OTP also proposed that a deferral account be established for any rate case expenses that are collected for any period of more than three years. These amounts would be subject to a credit toward expenses in OTP's next rate case. OTP noted that this approach was taken in the Commission's decision in the *2006 Xcel Energy Gas Rate Case*.[471]

350. The Department and the OAG recommended amortization over five years. The Department asserts that the historical average of years between the Company's rate cases is 6.4 years.[472] The OAG relies on the fact that is has been over 20 years since the Company's last rate case.[473] Both the Department and the OAG rely on prior history that is not representative of the future, specifically the economic conditions that prevailed in the electric utility industry and for the Company between 1987 and 2007. OTP noted that the average duration between its rate cases before 1987 was 2.75 years.[474]

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[467] AG Processing Brief at 1-3.
[468] Ex. 34, Brutlag Direct at 47-49.
[469] Ex. 37, Brutlag Rebuttal, trade secret version, at 16, and Schedule 11.
[470] Ex. 22, Beithon Rebuttal at 32. The Company's acceptance of the Department's recommendation regarding allocation reduced the 3-year amortization from $498,333 to $486,822.
[471] *Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service In Minnesota*, Docket No. G-002/GR-06-1429 ("*2006 Xcel Energy Gas Rate Case*").
[472] Ex. 99, Lusti Direct at 28.
[473] Ex. 80, Lindell Surrebuttal at 3.
[474] Ex. 22, Beithon Rebuttal at 33.

351. OTP noted that it has begun a substantial capital investment program, which is estimated to involve approximately $759 million of investment over the next 5 years, including approximately $336 million relating to Big Stone II and $423 million relating to other projects.[475] OTP maintained that going forward with either category of investment will require frequent rate case filings.

352. The Commission noted the significance of utility plans and utility investment cycles in approving a three year amortization in the *2006 Xcel Energy Gas Rate Case*. [476] With OTP's investment plans, OTP's plans regarding rate case filings, and the dissimilarities between the current period and conditions since 1987, the three year amortization period is reasonable. Establishing a deferral account for rate case expenses recovered beyond the three year period is a sound approach to avoid over-recovery from ratepayers.

XVI. CHARITABLE CONTRIBUTIONS AND ORGANIZATIONAL DUES.

353. OTP has proposed including in its revenue requirement $92,377 for Charitable Contributions, which reflects 50 per cent of OTP's charitable contributions.[477] OTP provided in its case filing the information required by the Commission's Statement of Policy on Charitable Contributions.[478] The Department agreed with the amount of Charitable Contributions that OTP Tail has proposed for recovery.[479]

354. OTP also proposed inclusion in its revenue requirement $211,315 of organizational dues.[480] The Department recommended a $9,061 adjustment which would reduce the amount included in OTP's revenue requirement for organizational dues to $202,254.[481] The Department's recommended adjustment to organizational dues is in part based on a concern regarding out-of-state Chamber of Commerce dues. The Department also noted that some of the amounts paid may be going to organizations not located in Minnesota.

355. AG Processing argued that a portion of Otter Tail's charitable contributions and organizational dues should be allocated to its non-regulated businesses and only the remainder should be included in the revenue requirement. [482]

356. OTP pointed out that, unlike charitable contributions that are directly assigned to Minnesota and must be to eligible recipients, organizational dues are allocated to jurisdictions like most other expenses.[483] Therefore, it would be inappropriate to disallow payments for dues to organizations located outside Minnesota based on that fact alone. If that were done, then amounts paid to Minnesota-based organizations should be 100 percent allocable to Minnesota rates. It would be inappropriate for Minnesota ratepayers to cover the costs of only an allocated share of Minnesota based dues, and nothing for out-of-state dues.

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[475] Ex. 15, Moug Rebuttal at 2.
[476] *2006 Xcel Energy Gas Rate Case*, Commission Findings of Fact, Conclusions of Law, and Order at 8 (September 10, 2007).
[477] This amount reflects Otter Tail's agreement with the Department that the amount originally proposed for recovery ($141,334) should be adjusted down by $46,604 to arrive at a total of $92,377.
[478] Volume 3, Schedule G-2 under PUC Policy Information Tab.
[479] Ex. 102, Lusti Surrebuttal at 15.
[480] Ex. 20, Beithon Direct at 59-60.
[481] Ex. 90, Johnson Rebuttal at 11-12.
[482] Ex. 57, Glahn Surrebuttal at 9.
[483] Ex. 24, Beithon Surrebuttal at 3.

357. OTP accounted for out-of-state Chamber of Commerce dues below-the-line, and they were not part of the amount OTP included in its revenue requirements. Only the contributions and dues attributable to OTP's regulated utility business have been included in its request, and no amount has been included that would be attributable to contributions or dues associated with OTP's non-utility businesses.[484]

358. Because OTP included only OTP's charitable contributions and organizational dues in its revenue requirement, allocating a portion of this amount to Otter Tail Corporation's non-utility subsidiaries would not be appropriate.[485] Direct assignment is generally favored as opposed to "indirect allocations" under Otter Tail's proposed Corporate Allocation Manual and prior Commission decisions.[486] Furthermore, if Otter Tail were to take an indirect allocation approach to these contributions and dues, it would require that the total aggregate contributions and dues be allocated.[487] There is no evidence in the record that would support such an approach or from which the outcome of such an approach could be determined.

359. OTP has met its burden of proof to show that its charitable contributions are recoverable pursuant to Minnesota Statute § 216B.16, subd. 9, and that its organizational dues have been included in revenue requirements consistent with the Commission's Order in OTP's last rate case and with the Commission's Statement of Policy on Organizational Dues.[488] No adjustment should be made to the amount of charitable contributions and organizational dues included in OTP's proposed revenue requirement.

XVII. DEMAND SIDE MANAGEMENT ("DSM") REBATE PROGRAMS.

360. In OTP's 1986 rate case, the Commission denied recovery for three DSM rebate programs -- thermal storage, water heaters, and dual fuel. OTP is requesting recovery of the expenses for similar rebate programs in this proceeding. At issue is $131,051 in expenses related to those three rebate programs.[489] Mr. Lindell and Mr. Glahn opposed cost recovery. Mr. Davis, on behalf of the Department, supports cost recovery subject to OTP making certain modifications to its water heating rebate. OTP agreed to the requested changes with some modification, and Mr. Davis accepted those modifications.[490]

361. One of the ways that a utility is able to meet peak needs is to avoid the peaks through DSM programs. Each of the rebate programs are designed to encourage customers to alter their usage patterns to reduce peak demand. The reduction in peak demand means reduced energy purchases during peak periods when energy is the most expensive and delay in adding expensive peaking generation facilities. DSM programs result in lower rates.

362. Mr. Glahn recites the concerns the Commission raised in 1986: (1) that those prior programs increased usage more than they reduced demand; and (2) that customers would buy the appropriate equipment without a rebate, making the rebates unnecessary.[491] Such participants are

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[484] Tr. V. 2 at 38-39, Beithon.
[485] *Id.*
[486] Docket 1008 Order at 5.
[487] Tr. V. 2 at 38-39, Beithon.
[488] Ex. 20, Beithon Direct at 59-60.
[489] Ex. 22, Beithon Rebuttal at 36. The initial request of $180,214 was reduced by $49,163 to remove a depreciation expense for retired load management equipment, as recommended by Mr. Davis.
[490] Ex. 84, Davis Surrebuttal at 2-3.
[491] Ex. 56, Glahn Direct at 5-8.

sometimes called "free riders." Mr. Glahn presented no evidence to support a finding that these are still valid concerns. Mr. Lindell asked that a cost benefit analysis be conducted.[492]

363. Mr. Davis is one of the Department's experts in the area of conservation and DSM programs. Mr. Davis determined that all three programs are cost effective from a societal and ratepayer impact perspective (as such, they meet the same societal test required of CIP programs). The Department's cost/benefit analysis demonstrates that the benefits gained from peak energy savings exceed the possible energy use promotion detriments. Mr. Davis' study responds to the Commission's concerns about inappropriately promoting energy use. There is no evidence challenging the results of his study.

364. Mr. Davis agreed with OTP that these programs are necessary to respond to alternative customer equipment options that are less energy efficient and that there is a need for incentives to make these beneficial programs successful. This responds to the Commission's prior concern about free riders, and there is no evidence in the record that challenged his findings.

365. Mr. Davis' only expressed concern with the program was how OTP's water heating rebate program was offered. OTP responded by changing the program to address those concerns.[493]

366. OTP has shown that these DSM programs meet the Commission's standards for approval. OTP should be allowed to recover its expenses related to these rebate programs.

XVIII. INVENTORY OF SUPPLIES AND MATERIALS.

367. The OAG observed that the amount of inventory of supplies and materials included in rate base increased by 19 percent from January 1 to December 31, 2006 (the test year period). The OAG asserted that the amount of increase was unreasonable and proposed that the increase be limited to 10 percent. That adjustment would reduce OTP's rate base by $363,000.[494]

368. OTP noted that the principal reason for the increase in inventories during the test year was that a large portion of OTP's service territory experienced a severe ice storm in late November and early December 2005. As a result, inventories of transmission and distribution poles, conductors, transformers, and related equipment were depleted. These inventories were replenished during 2006, causing a significant increase in inventory balances. Thus, the change in the beginning and ending balances (19 percent) appears large, while the average inventory was actually below normal.[495] Rate base is determined using a 13-month average.[496] Because the rate base is an average of the beginning and ending balances, if the initial inventory is lower than normal, then, all else being equal, the average rate base used to set rates will also be below the normal inventory level.

369. The increase in inventory was also, in part, the result of an increase in the cost of equipment, such as conductors and transformers, in recent years. For example, the cost of some cable rose 88 percent from 2005 to 2007 due to rising copper costs. During this same time period,

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[492] Ex. 79, Lindell Direct at 10.
[493] Ex. 82, Davis Direct at18-21.
[494] Ex. 79, Lindell Direct at 11-12.
[495] Ex. 36, Brutlag Rebuttal at 3.
[496] *Id.*

some transformers saw cost increases of 58 percent, also due to rising raw material costs, such as oil, steel, and copper.[497]

370. OTP experienced inventory shortage problems due to the 2005 ice storms. To address reliability concerns, OTP increased its inventory of some equipment over previous levels. The average balance of supplies and materials used in rate base for the 2006 test year is $5,772,171. By contrast, the average balance of supplies and materials for actual year 2007 was $6,691,532. The significantly higher 2007 inventory balance supports a finding that the 2006 test year amount is conservative.[498]

371. The OAG asserted that OTP's lower inventory was the result of mismanagement and, therefore, the amount of the increase should be limited to 10 percent.[499] OTP adequately explained the depletion of inventories as resulting from a severe ice storm and not mismanagement. OTP's proposed average inventory in rate base was reasonable. The supplies and materials inventory included in OTP's 2006 test year is representative of future inventory levels. No adjustment is needed.

XIX. THE LEVEL OF FUEL STOCKS INCLUDED IN RATE BASE.

372. The OAG observed that the level of fuel stocks included in rate base increased by 16 percent during 2006 (the test year period). The OAG asserted that the increase was unreasonable and proposed that the increase be limited to 10 percent. That adjustment would reduce the rate base by $252,000.

373. OTP noted that during 2005 and early 2006, two of OTP's generating plants, Big Stone I in northeastern South Dakota and Hoot Lake near Fergus Falls, Minnesota, experienced problems with the rail delivery of Wyoming coal. According to OTP, Big Stone I's coal stockpile would typically contain 30 days of coal. At the end of 2005, the stockpile was at 25 days. In March of 2006, that stockpile was reduced, at its lowest point, to 15 days. OTP described the shortage as so severe that the production at Big Stone I was reduced for seven weeks to allow the coal supply to build up. At Hoot Lake, the stockpile of coal is typically at 20 days. At the end of 2005, the coal stock was at 15 days. As the delivery situation improved, stockpiles were built up to more typical levels. OTP maintained that, while the change in the beginning and ending balances (16 percent) appears large, the average fuel stocks on hand was actually below normal.[500]

374. As with the inventories for supplies and materials, the rate base amount for fuel stocks was determined using a 13-month average.[501] OTP noted that, if the initial level of fuel stocks is lower than normal, then, all else being equal, the average rate base will also be below the normal fuel stock level.

375. OTP noted that during much of 2007, the days of coal supply maintained in the stockpiles at both the Big Stone I Plant and the Hoot Lake Plant were slightly higher than prior historical levels. OTP defended this decision as needed to provide a cushion in the event that delivery problems recurred. OTP expressed its intention to maintain these higher inventories as a hedge against possible future delivery delays. While the days of coal supply fluctuated during the year, the average days of supply for Big Stone I in 2006 was 29. In 2007, Big Stone I averaged 40

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[497] Ex. 36, Brutlag Rebuttal at 4.
[498] *Id.*
[499] Ex. 80, Lindell Surrebuttal at 26.
[500] Ex. 36, Brutlag Rebuttal at 5.
[501] *Id.*

days of supply. The average days of supply maintained for Hoot Lake in 2006 was 24. Hoot Lake's average days of supply in 2007 increased to 26.

376. OTP noted that coal costs increased in 2007 over 2006 costs. During 2007, the average cost of coal to the Big Stone I Plant increased by 6 percent, and the cost of coal to Hoot Lake increased by 18 percent. The cost of coal also increased at another generating plant (Coyote Station) by 6 percent. Coyote is a mine-mouth plant where coal stock piles are unaffected by rail delivery service.

377. The average fuel stocks value in the 2006 test year (the same as actual 2006) for Minnesota was $3,221,806, while the average value of 2007 fuel stocks was $4,092,393. The higher 2007 fuel stocks indicate that the 2006 test year amount is conservative.

378. The OAG suggested that the lower initial fuel stocks were the result of mismanagement and, therefore, the amount of the increase should be limited to 10 percent.[502] OTP adequately explained the depletion of fuel stocks as resulting from rail delivery problems. These problems arose from independent parties and they do not adversely reflect on OTP's management practices. Having experienced fuel interruptions, a reasonable response is to increase the fuel on hand.

379. OTP's identified levels of fuel stocks included in the 2006 test year were reasonable.

XX. FUEL COST ISSUES.

380. The MCC raised three issues related to fuel cost and fuel cost recovery: (1) whether OTP should adopt an additional key performance indicator ("KPI") related to fuel costs; (2) whether OTP should use the same fuel clause adjustment procedure in all three states; and (3) whether OTP should amend its tariff to clarify its treatment of FERC 151 Fuel Inventory. The Department supported the idea of creating a KPI for fuel costs. The Department questioned whether OTP is double recovering its O&M expenses.

A. OTP's KPIs.

381. KPIs are a management tool used by OTP for measuring performance in meeting key goals and objectives. OTP has established five principle components to its KPI system: They are: (1) Customer Satisfaction; (2) Service Reliability; (3) Generating Plant Availability; (4) Employee Safety; and (5) Financial Performance. For each KPI, OTP has objective and concrete measurements of performance. MCC and the Department requested that the Commission require OTP to establish a sixth KPI for fuel costs.

382. OTP noted that , in addition to the five major KPIs, each OTP Department has its own KPIs. Fuel costs are a separate KPI within the Generation Department. OTP's management has determined that within the hierarchy of its KPI system, the KPI for Generating Plant Availability is the more appropriate primary indicator of performance in economic energy supply because it is specific and because of the significant impact that outstanding performance in Generating Plant Availability can have on the narrower goal of fuel and purchased power costs.[503]

383. OTP described availability as representing the portion of time that a generating unit is available to operate, including consideration of the lost capacity effects of partial equipment

[502] Ex. 80, Lindell Surrebuttal at 26.
[503] Ex. 7, MacFarlane Rebuttal at 10.

deratings when a unit is available but at less than full capacity. OTP has invested in very low-cost generating plants that typically produce energy well below market prices. This makes performing well on the availability measure very important. OTP can reduce its overall energy costs by making sure it gets every possible megawatt hour out of those very low-cost generating plants. Availability has more impact on OTP's fuel and purchased power costs than does any other factor over which OTP has any reasonable control.[504]

384. OTP noted that it has implemented KPIs as part of its incentive compensation mechanism, and the Commission has not historically involved itself in the day-to-day management of OTP down to the level of impacting compensation programs. There has been no showing that establishing a sixth KPI for fuel costs is needed for encouraging improved performance in limiting fuel costs.

B. Different FCA Mechanisms Used in OTP Service Areas.

385. OTP is required to use a different FCA mechanism to recover changes in fuel costs in each of the three states in which it operates. Mr. Schedin expressed concern that OTP could be over-recovering its fuel costs as a result. OTP noted that no evidence was offered that over-recovery has ever occurred.[505]

386. Each State Commission establishes the FCA methodology used within its jurisdiction and that methodology applies to several utilities in each state. The MCC did not indicate which state's model the Minnesota Commission should allow OTP to use in order to eliminate some of the inconsistency. MCC has not demonstrated that a change in the FCA mechanism is needed.

C. Tariff Modifications to Incorporate USOA Requirements.

387. The MCC proposed changing OTP's tariff to restate the accounting requirements established in the FERC Uniform System of Accounts (USOA) with respect to fuel handling costs. OTP objected to the proposal as unnecessary and unreasonable. OTP noted that this change would require utilities to replicate the FERC system of account requirements in their tariffs.[506]

388. The account requirements are established by FERC, and pursuant to Minn. Rule pt. 7825.0300, all public utilities must comply with those requirements. The MCC has presented no evidence that OTP is out of compliance with the USOA requirements. There has been no showing of a benefit from OTP being required to replicate all of the state and federal requirements that apply to them in their tariffs. MCC's proposal to incorporate USOA requirements should not be adopted.

D. O&M Costs

389. The Department expressed concern that OTP's bidding of resources into the MISO Day 2 market did not include all costs imposed to operate and maintain generators producing energy into the market (called "O&M"). The Department asserted that the effects of this practice must be taken into account in setting rates. Where a generation unit is dispatched by MISO, the Department maintained that O&M costs should be included in the MISO Day 2 charges to be paid

[504] *Id.*
[505] OTP Brief, at 158.
[506] OTP Brief, at 158-159.

by the purchaser of the energy produced by the unit. The Department noted that all of these costs would be included in the monthly FCA of each utility purchasing the energy from the unit.[507]

390. The Department contended that if a utility fails to adjust out of base rates the MISO-bid-related O&M expenses (non-fuel expenses), there will be a double recovery of such expenses.[508] OTP maintained that it is not recovering the O&M expense in generation bids in the MISO Day 2 Market. The Department maintained that OTP did not provide sufficient support for its assertion that it is not recovering the O&M expense of third parties included in generation bids from the MISO Day 2 market. The Department noted that the MISO market allows the inclusion of such O&M expenses in the price quoted for energy entered for sale into the market. The Department characterized OTP's choice to not recover the O&M expense from the MISO market as a decision to have ratepayers pay those costs. The Department contended that OTP's shareholders, rather than ratepayers, should shoulder the burden of these costs.[509]

391. The Department expressed its position as follows:

> While it is appropriate to pay the third-party generator what it costs for them to produce energy from the plant, it is not reasonable for OTP's ratepayers to pay for both the third-party generator O&M costs via the FCA and OTP's generation O&M costs in rate base.[510]

392. OTP contended that there is no double recovery arising out of the MISO Day 2 market because:

1. OTP recovers its O&M expenses in its base rates.
2. OTP uses an O&M cost component when developing its price for bidding generation into the market.[511]
3. OTP removes the cost of the O&M when it books the transaction to the FCA (preventing a double recovery of the O&M costs -- it is recovered only in base rates and not through the FCA).[512]
4. Any third-party revenues in excess of costs are wholesale margins and are credited back to the base rate revenue requirement.
5. OTP is required to pay the market price established by third-party providers when it buys energy, and that market price may include the third-party providers' O&M costs.[513]
6. OTP's ratepayers will only pay for the O&M costs of a third-party provider for energy that OTP has not produced.[514]

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[507] Ex. 95, Campbell Direct at 44-45.
[508] Ex. 98, Campbell Surrebuttal at 19-20
[509] Department Brief, at 40-41.
[510] Ex. 98, Campbell Surrebuttal at 19-20.
[511] Ex. 96, Campbell Direct at 47.
[512] Ex. 22, Beithon Rebuttal at 27.
[513] Tr. V. 2 at 38.
[514] *Id.*

393. OTP noted that O&M payments received from third parties are included within the asset-based margin process and are, therefore, credited to the base rate revenue requirement (where the O&M costs reside). This crediting process prevents double recovery of O&M expenses.

394. Ratepayers only pay the O&M expenses for OTP generation at the level set in the test year and receive asset-based credits for sales made to third parties. Ratepayers also pay the O&M costs of third-party providers, but that is a separate cost and is not double recovered.

395. The credit requested by the Department to recognize the payment of O&M expenses by third parties is already occurring through the asset-based margin credit process. If the Commission seeks to require a more direct crediting of O&M costs, that could be accomplished by crediting asset-based margins to the fuel cost revenue requirement rather than crediting the base rate revenue requirement.

396. OTP has met its burden to show that its O&M expense is reasonable and that it is not double recovering these expenses.

XXI. RATE BASE.

A. Agreed-upon Adjustments to Rate Base.

397. In setting rates for a public utility, the Commission must determine the total level of investment by the utility in its "utility property used and useful in rendering service to the public."[515] In utility rate cases, such investments are referred to as the utility's rate base. OTP filed a proposed rate base of $207,779,343.[516] Through the course of the proceeding, the Department and OTP agreed on the following adjustments to the rate base as initially filed by the Company:

- Depreciation Reserve Related to 2007 Depreciation Rates. Decrease test-year rate base by $636,397.[517]

- Depreciation Reserve Related to Big Stone I. OTP Errata recommended adjustment to decrease test-year rate base by $58,816.[518]

- Big Stone I Acquisition Adjustment, removal from rate recovery. Decrease test-year rate base by $245,833.[519]

- D1 Allocation Adjustment. All non-firm/curtailable loads are excluded from OTP's Generation Demand Allocator (D1) calculation. The overall effect on rate base is a reduction in OTP's production plant, accumulated depreciation, and fuel stock balances for the Minnesota jurisdiction.[520] OTP's production plant, accumulated depreciation, and fuel stock balances for the Minnesota jurisdiction decrease by $1,597,236, $926,120, and $18,403, respectively.[521]

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[515] Minn. Stat. § 216B.16, subd. 6.
[516] OTP Ex. 34 (BCB-1), Sch. 1 (Brutlag Direct).
[517] DOC Ex. 99 (DVL-9) (Lusti Direct); OTP Ex. 36 at 1-2 (Brutlag Rebuttal).
[518] DOC Ex. 108, Attachment DVL-H-4, Column (d) (Lusti Hearing Statement); OTP Ex. 35 (Errata Testimony and Workpaper).
[519] DOC Ex. 95 (NAC-18) (Campbell Revised Direct Testimony); OTP Ex. 36 at 2-3 (Brutlag Rebuttal).
[520] DOC Ex. 91 (MAJ-S-15, Revised), Column (f), Lines 3, 4, and 5 (Johnson Surrebuttal).
[521] DOC Ex. 106 (Johnson Hearing Statement); DOC Ex. 108, Attachment DVL-H-4, Column (e) (Lusti Hearing Statement).

398. The Department noted that OTP included the cash working capital requirements for operation, maintenance, and other expenses. OTP applied lead/lag study factors to its test-year O&M expenses to determine its cash working capital requirement. The Department determined, after analysis, that these lead/lag factors were reasonable. The Department and OTP agreed that the lead/lag study cash working capital calculations will need to be adjusted to reflect all of the changes to revenue requirements as finally determined by the Commission.[522]

B. Disputed Adjustment to Rate Base.

399. The Department identified Transmission Demand Factor (D2) as the only outstanding rate base issue. The Department and OTP agreed that all non-firm/curtailable loads should be excluded from OTP's Transmission Demand Allocator (D2) calculation. The Department and OTP agreed to the revised D2 allocator for Minnesota totaling 50.791191%.[523]

400. However, the Department and OTP did not agree on other aspects of the D2 allocator, with respect to OTP's assertion that the Company's 41.6kV and 69kV lines are transmission facilities and that the costs associated with them should be allocated on the same basis as OTP's 115kV and 230kV lines.[524] OTP has shown that its 41.6 kV facilities are largely located in North and South Dakota. OTP recommends that all transmission facilities be allocated using its proposed Transmission Demand Factor (D2). Using OTP's Transmission Demand Factor (D2), all of OTP's transmission investment and expense, regardless of voltage or location, is allocated using a single peak-demand allocation factor. The result is that Minnesota is allocated 51.892532 percent of OTP's transmission investment and expense in the test year due to Minnesota's higher load factor. The basis for the Department's position relative to the load factor is as follows:

> While load factor is one relevant element relating to the size (capacity) of the transmission facilities needed to serve a customer with a high load factor, using load factor alone ignores relevant geographical considerations such as the miles of transmission lines in a given state needed to serve customers located throughout the state. The [Department's] concern is with allocating transmission costs on a more cost-causative basis which creates a reasonable and fair allocation for Minnesota. For example, it is not appropriate to require Minnesota ratepayers to pay for subtransmission lines in North Dakota which are needed to provide service to customers remotely located in that state. Therefore, it is unreasonable for Minnesota to pay 51.892532 percent of the transmission investment and expense related OTP's 41.6kV facilities when only 31.9383 percent of these facilities are located in Minnesota.[525]

401. The Department urged a "common sense" standard that more of OTP's lower-voltage 41.6kV transmission facilities costs be allocated to North and South Dakota, since the facilities are located in those states.[526] The Department proposed a two-tier system for allocating costs. The first tier includes larger facilities (50kV and above) which are allocated using OTP's D2 Transmission Demand Factor. The second tier consists of smaller transmission facilities (below 50kV) which are allocated based on the number of transmission line miles per state jurisdiction.

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[522] Ex. 99, Lusti Direct at 9-10; Ex. 102, Lusti Surrebuttal at 17; Ex. 34, Brutlag Direct at 29-31; and Ex. 36, Brutlag Rebuttal at 2.
[523] Ex. 106, Johnson Hearing Statement.
[524] OTP Ex. 7 at 3-7 (McFarlane Rebuttal); OTP Ex. 18 at 4-25 (Rogelstad Rebuttal).
[525] DOC Ex. 91 at 6 (Johnson Surrebuttal).
[526] DOC Ex. 91 at 7 (Johnson Surrebuttal).

OTP has failed to show how its demand allocation method is an appropriate or reasonable method to allocate transmission expense. The two-tier method is a more reasonable and cost-causative way to allocate OTP's lower-voltage 41.6kV facilities.[527] The overall effect on rate base is a reduction in OTP's transmission plant and accumulated depreciation balances for the Minnesota jurisdiction by $22,440,375 and $8,714,703, respectively.[528] In addition, OTP's transmission expense is reduced by $1,322,463 on a Minnesota jurisdictional basis.[529] The Department's allocation approach is superior and should be adopted.

XXII. RATE DESIGN.

A. Class Revenue Apportionment.

402. In setting rates, an important consideration in addition to the overall revenue requirement is how much of that needed revenue is to be paid by each customer class. The Commission has described the factors to be considered as follows:

> The Commission requires utilities to file a CCOSS because the cost a utility incurs to provide service is one factor the Commission considers in determining how much each customer class should contribute to meeting the utility's revenue requirement, and how to recover each class' share of the revenue requirement from the members of the class. Other factors include economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation, ability to pay; and ability to bear, deflect or otherwise compensate for additional costs.[530]

403. OTP apportioned its total revenue responsibilities among its rate classes based on its CCOSS and its rate design objectives, including the objective of maintaining reasonable rate continuity, mitigating rate shock, and encouraging the efficient use of resources.[531] OTP proposed the following allocation and noted the impact of asset-based margin credits through the FCA as follows:

Class Revenue Responsibility — Proposed increase by class[532]					
			Proposed Increase by Class Responsibility		
Customer Class			**Amount of Increase (as originally proposed)**	**Percent Increase**	**Percent Increase With FCA Adjustment**
Residential			$4,522,094	12.50%	9.10%
Farms			286,159	13.25%	9.20%
General Service			1,538,033	5.88%	2.50%
Large General Service			6,081,942	10.50%	5.25%
Irrigation			40,461	14.00%	9.51%

[527] DOC Ex. 106 (Johnson Hearing Statement).
[528] DOC Ex. 90 (MAJ-R-6), Column (g), Lines 4 and 8 (Johnson Rebuttal).
[529] DOC Ex. 90 (MAJ-R-7), Column (g), Line 4 (Johnson Rebuttal).
[530] *ITMO the Application of CenterPoint Energy Minnesota Gas, a Division of CenterPoint Energy Resources Corp., for Authority to Increase Natural Gas Rates in Minnesota*, PUC Docket No. G-008/GR-05-1380, at 38 (Commission Findings of Fact. Conclusions of Law, and Order issued November 2, 2006) (https://www.edockets.state.mn.us/EFiling/ShowFile.do?DocNumber=3560745) (*CenterPoint Energy 2006 Order)*.
[531] Ex. 20, Beithon Direct at 63.
[532] *Id.* at 64.

Lighting			273,006	11.50%	9.16%
OPA			167,790	14.00%	9.15%
Controlled Service Water Heating			215,284	15.00%	10.05%
Controlled Service Interruptible			1,298,236	40.00%	31.80%
Controlled Service Deferred			86,516	12.00%	6.03%

404. The OAG recommends a flat, across-all-classes rate increase, without any regard for OTP's embedded CCOSS.[533] Such an approach would subsidize residential customers by having costs incurred by that class paid for by other customer classes.

405. MCC recommends a strict adherence to the CCOSS, without any regard for non-cost factors.[534] Such an approach would shift costs away from members of the LGS class.

406. The Department analyzed OTP's rate structure and concluded that significant subsidies currently exist between customer classes. The Department proposed that the revenue increase be apportioned to reduce these subsidies. As described by Dr. Griffing:

> The largest percentage increases come for the customer classes receiving the largest percentage subsidies and thus having the largest relative differences between present revenues and full-cost recovery revenues. For example, Controlled Service Water Heating has a gap between current revenues and full-cost recovery revenues of $868,570; Otter Tail's proposed revenue apportionment covers $215,284, or about one-fourth of the gap. Under my proposed revenue apportionment, $437,354, or slightly more than half of the gap is closed. The same is true for Irrigation, where the corresponding amounts are $149,741, $40,641 (one-fourth of the gap), and $77,608 (slightly more than half of the gap). For the Residential class, the difference between current revenues and full-cost recovery revenues is $6,334,726, Otter Tail proposes to cover $4,522,094 (about 71 percent of the difference), while my proposal is to cover $5,138,259 (81.1 percent of the difference).[535]

407. The Department's proposed revenue allocation between classes is as follows:

Department — Proposed Increase by Class[536]					
			Proposed Increase by Class Responsibility		
Customer Class			**Proposed Revenue Increase**	**Percent Increase**	**Total Revenues as Percent Increase Total Required Revenues**
Residential			$5,138,259	14.20%	97.19%
Farms			352,442	16.32%	95.13%
General Service			462,356	1.77%	105.00%

533 OAG Brief at 9.
534 MCC Brief at 15; Tr. V. 4 at 137.
535 Ex. 88, Griffing Surrebuttal at 13-14.
536 Ex. 88, Griffing Surrebuttal, MFG-S-2.

Large General Service			6,081,942	10.50%	101.30%
Irrigation			77,608	26.85%	83.56%
Lighting			371,147	15.63%	99.51%
OPA			198,048	16.52%	95.96%
Controlled Service Water Heating			437,354	30.47%	81.28%

Controlled Service Interruptible			1,310,914	40.39%	99.46%
Controlled Service Deferred			79,415	11.02%	101.58%

408. OTP noted that many individual OTP customers take service under two or more rates resulting in a cumulative rate impact (*e.g.*, residential service, and one or more demand controlled rates).[537] For example, OTP's proposed Controlled Service Water Heating Rate, by its nature, will not likely be the sole rate under which a customer takes service. Instead, such a customer will also take service under another, less use-specific rate, such as the Residential Service Rate. That customer will experience both the residential increase and the Controlled Service rate increase. OTP maintains that the cumulative rate impact of these two rates increases should be considered in the revenue apportionment. OTP argues that the Department's proposal did not take into consideration the cumulative rate impact that a single customer could experience if taking service under two or more rates.[538]

409. The Commission has historically considered a variety of cost and non-cost factors when designing rates. As explained in *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*:

> Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. The commission may then balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among the consumer classes.[539]

410. The Commission has identified a number of cost and non-cost factors to consider when determining customer class revenue responsibility. Both types of factors are important to determine just and reasonable rates. These factors identified by the Commission include avoidance of rate shock for individual customer classes, low-income customers' ability to pay, a company's ability to recover the rate increase from others, the ability of companies to decrease the burden of a rate increase through tax deductions, and the recognition of the historical continuity of rates and rate increases.[540]

411. OTP's proposed revenue apportionment minimizes the effects of rate shock, while modestly addressing subsidies between customer classes. The Department's proposal reduces subsidies, but results in larger increases for some classes that could constitute rate shock. The across-classes proposal does not address subsidies, but mitigates rate shock, since all classes are affected by the same percentage increase. Of the various revenue allocation proposals, OTP's best reflects and balances the relevant cost and non-cost factors and, therefore, OTP's proposed revenue apportionment is recommended.

[537] Tr. V. 4 at 194-195.
[538] *Id.*
[539] *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W. 2d 350, 357 (1977).
[540] *Id.*

B. Use of Marginal Costs in Rate Design.

412. OTP developed its rate design from the revenue requirements identified in its marginal cost of service study.[541]

413. MCC and Enbridge challenged the use of marginal cost instead of the embedded CCOSS to design rates, and also challenged how marginal capacity costs were developed.

414. There are three primary reasons for using marginal costs in rate design. First, rates set at marginal cost provide the most efficient price signals to consumers, and promote the wise use of resources.[542] Second, the use of marginal cost pricing reduces cross subsidies.[543] Cross subsidies can arise when costs attributable to consumption by one customer or group of customers are recovered from another customer or group of customers.[544] Third, when rate structures are based on marginal cost, the utility's revenues are more likely to track its total costs as electricity consumption changes.[545]

415. OTP's proposed rate design was based on marginal costs, as adjusted to match the proposed revenue requirement in a manner that retained the benefit of marginal cost price signals.[546]

416. MCC witness Schedin and Enbridge witness Erickson argue that the generation portion of OTP's marginal cost study is too short-term focused and that it should have reflected the future costs of Big Stone II, OTP's next planned baseload addition.[547] However, a marginal cost study from which rates will be designed should reflect the marginal costs that will be incurred during the period the proposed rates are expected to be in effect.[548] Otter Tail's marginal cost study does that.[549] This approach results in price signals that are as close as possible to the expected costs to supply additional kW and kWh while the rates are in effect.[550] For example, if OTP needs additional (or less) capacity during the period the rates are in effect, it will buy (sell) capacity. OTP's marginal cost study was properly based on the market cost of such capacity.[551] Even when OTP builds additional generating capacity, its marginal capacity cost will still be a function of market prices.[552] It is appropriate to use market prices because they reflect the actual effect on OTP and its customers as a whole, of a change in energy use in a given hour.[553] OTP's approach is consistent with common industry practice to base marginal costs on market price forecasts.[554]

417. OTP maintained that reflecting the capacity costs of future baseload additions, such as Big Stone II, in current demand charges would be inappropriate. MCC and Enbridge argue that

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[541] Ex. 29, Parmesano Direct at 4-5; and Ex. 41, Prazak Rebuttal at 2. This Marginal Costs Study for purposes of rate design is different from the embedded class cost of service study that was used for the OTP's proposed revenue apportionment. Ex. 29, Parmesano Direct at 6.
[542] Ex. 29, Parmesano Direct at 4.
[543] *Id*. at 4-5.
[544] *Id*.
[545] *Id*. at 5.
[546] *Id*. at 7.
[547] Ex. 60, Schedin Direct at 38, 31; and Ex. 69, Erickson Direct at 19.
[548] Ex. 30, Parmesano Rebuttal at 3.
[549] Id.
[550] *Id*.
[551] *Id*. at 6.
[552] *Id*.
[553] Ex. 48, Parmesano Evidentiary Hearing Statement at 4.
[554] Ex. 30, Parmesano Rebuttal at 7-8.

such costs should be reflected in current demand charges. OTP argues that this approach would effectively base one rate component (demand charges) on the costs of future capacity additions, and another component (energy charges) on current marginal costs. OTP maintains that this would result in a distortion in the signal regarding the relative costs of energy and capacity.[555]

418. For these reasons, OTP's use of a marginal cost study to design rates should be accepted. In addition, OTP's use of market prices as the basis for OTP's marginal capacity costs should be accepted, and its proposed rates should not be altered in an attempt to reflect the capacity costs anticipated for the addition of Big Stone II.

419. MCC asserted that OTP provided no cost study justification for its voltage level discounts. OTP provided marginal energy and capacity costs by voltage level, showing the differences in marginal cost for primary and transmission service, compared to secondary service and the differences in charges.[556] MCC's position is unfounded.

C. The Breakeven Methodology.

420. OTP provided an embedded CCOSS that used the same classification methods as were used in the CCOSS approved in OTP's 1986 rate case.[557] The only parties to comment on the CCOSS were the Department and MCC. OTP accepted the two modifications to the CCOSS requested by the Department. MCC proposed that a breakeven methodology be used to determine the portion of production plant costs to treat as demand versus energy costs.[558] This proposal was opposed by both OTP and the Department.

421. The Department recommended acceptance of OTP's CCOSS, as adjusted to reflect OTP's agreed upon adjustment to the D-1 factor and to allocate conservation expenses in a manner consistent with Mr. Davis' proposal.[559] OTP accepted the Department's requested modifications.

422. OTP used an equivalent peaker methodology to determine the portion of production plant costs to treat as demand versus energy costs. While the MCC initially proposed using its breakeven methodology for both CCOSS and JCOSS purposes, at the evidentiary hearing, Mr. Schedin stated that "in the interest of not impacting the total revenue requirement due from the Minnesota jurisdiction, … I would be satisfied with just using it for the CCOSS in Minnesota."[560] Using the breakeven methodology in the JCOSS would raise a concern whether the North Dakota and South Dakota Commissions would adopt a methodology that has not been adopted by any state commission. A unilateral change in a jurisdictional allocation is likely to result in an unrecoverable total company revenue requirement.

423. The breakeven methodology reallocates production plant costs from energy to demand. That, in turn, benefits customer classes that use more energy per unit of demand (high load factor customers).[561] Mr. Schedin testified that using the breakeven methodology in the CCOSS, as compared to the equivalent peaker methodology, would shift $942,000 in cost responsibility away from the high load factor customers in the Large General Service ("LGS") class

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[555] *Id*. at 9.
[556] Ex. 48, Parmesano Hearing Statement at 3.
[557] Ex. 119, Ouanes Direct at 6.
[558] Tr. V. 3 at 134.
[559] Ex. 121, Ouanes Surrebuttal at 6.
[560] Tr. V. 3 at 134.
[561] Tr. V. 3 at 136.

to lower load factor classes and customers (primarily to the Residential Class because of its comparatively lower load factor).[562]

424. OTP's Cost Allocation and Procedure Manual for Jurisdictional and Class Cost of Service Studies explains the equivalent peaker methodology as follows:

> The determination of Base and Peak Demand amounts is based on the premise that all plants are or can be used to supply peak demand. However, base load plants (steam and hydro) are used to supply the bulk of the energy used on the system. Therefore, the base load plants have a dual function of supplying both peak energy and demand. The … classification of production plant into base and peak categories recognizes this fact and assigns a portion of the base load plants to each of these functions. The underlying assumption is that the cost to supply a peak kW of demand capacity to the system is the cost of a peaking plant.[563]

425. The equivalent peaker methodology (also called a stratification methodology) was approved for use in OTP's 1986 rate case and in Xcel Energy's previous seven rate cases.[564] In the *2005 Xcel Energy Rate Case*, the Commission explained why the stratification methodology is reasonable, stating as follows:

> Electric utilities incur both fixed and variable costs. The cost of building a generator is generally fixed; they do not change in proportion to the amount of energy generated. In contrast, many operating costs are variable; they change depending on how much the plant is operated. Because a utility must build its plant sufficient to supply the electricity required by customers even on days of peak demand, fixed plant costs are typically regarded as demand-related costs. In contrast, energy-related costs—such as the cost of fuel or electricity purchased from other generators—are typically variable.
>
> But not all energy-related costs are variable. For example, a utility may buy a generator that is expensive to build but uses inexpensive fuel (typical of a "baseload" generator) over a generator that is inexpensive to build but requires expensive fuel (typical of a "peaking" generator). In this case, the choice to incur extra fixed building costs may be understood as a substitute for incurring extra fuel costs.[565]

426. The record in this proceeding is consistent with the Commission's rationale in the *2005 Xcel Energy Rate Case*. It is the need for both capacity and low-cost energy in excess of that provided by a peaking facility that justifies incurring the higher capital costs associated with a baseload plant. In explaining the relationship between the investment and energy costs, Dr. Parmesano stated :

> As the NARUC Manual that Mr. Schedin quotes makes clear [*see*, for example, NARUC Manual, p. 49, 53-54], utilities invest in generation capacity with fixed costs higher than the fixed costs of a peaker only if they expect to run the unit for enough hours of the year to offset the higher fixed costs with fuel savings. Therefore, a

[562] Ex. 61, Schedin Direct at 7.
[563] *Id*. at 13-14.
[564] *See generally,* Docket Nos. E-002/GR-77-611, E-002/GR-80-316, E-002/GR-81-342, E-002/GR-85-558, E-002/GR-91-1, E-002/GR-92-1428, and E-002/GR-05-1428.
[565] *2005 Xcel Energy Rate Case*, *supra*, Commission Order at 30-31.

significant share of the fixed cost of a baseload plant is incurred to provide inexpensive energy.[566]

427. MCC notes that Mr. Schedin and Dr. Parmesano agree that, from a resource planning perspective, a baseload plant will be built once the operating hours exceed those appropriate for a peaking plant. MCC maintains that this agreement implies support for the breakeven analysis.[567] Dr. Parmesano did not indicate that there any correlation between the resource planning decision and the determination of what is demand related cost in a cost of service study. Dr. Parmesano characterized the foundation of OTP's approach as follows:

> Beyond the cross-over point, a baseload unit continues to provide energy savings that offset some of its fixed costs. This fact is the foundation of the equivalent peaker approach used by OTP and Xcel Energy and many other utilities. It is also the foundation of all the many "Energy Weighting Methods" described in the NARUC manual.[568]

428. Mr. Schedin asserted that the proposed Big Stone II plant would be built to meet peak (demand) rather than energy needs. He maintained that baseload plant costs should be recovered as demand cost component, stating:

> The demand deficiency forecasts in OTP's revised certificate of need application for Big Stone Unit No. 2 and the lack of energy deficiency forecasts clearly demonstrates that this new large baseload unit is being proposed on the basis of meeting OTP's peak demand not energy, i.e., the need is demand driven rather than energy.[569]

429. Department witness Dr. Ouanes disagreed with Mr. Schedin's argument on two grounds. First, Dr. Ouanes maintained that "there is no reason why a utility would incur the higher capacity cost of baseload generation if not for the lower cost energy baseload plants provide."[570] Second, the need for Big Stone II is based on energy and capacity, described in the *Big Stone II* proceeding as follows:

> The issue of what need is the driving force behind the proposal for the Big Stone II facility appeared during the cross examination of multiple witnesses. This issue was originally discussed in my November 17, 2006 direct testimony at pages 10 to 17. The facts of the matter are the claimed need is for energy and capacity, that all utilities have an energy need, and not all utilities have a capacity need. Thus, energy is the issue linking all of the Applicants. Further if only capacity were needed, a baseload plant would not be proposed. If only energy were needed, a baseload plant could still be proposed. Thus, energy is the more important factor.[571]

At the evidentiary hearing, Mr. Schedin acknowledged that the plant is actually proposed for both capacity and energy needs.[572]

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[566] Ex. 30, Parmesano Rebuttal at 12-13.
[567] MCC Brief at 6.
[568] Ex. 48 at 1, Parmesano Hearing Statement.
[569] Ex. 61, Schedin Direct at 19.
[570] Ex. 120, Ouanes Rebuttal at 3.
[571] *Id.* (quoting Department witness Steve Rakow's testimony).
[572] Tr. V. 3 at 146-147.

430. Under the methodology used by OTP, 61.1 percent of the production plant is treated as energy related, while, under the breakeven analysis, Mr. Schedin treated only 16 percent as energy related.[573] Dr. Parmesano described this result as very extreme, stating:

> I am not aware of any commonly used embedded cost of-service method, other than treating all fixed costs as demand-related, that would define such a large share of production fixed costs as demand-related. And treatment of all fixed costs as demand-related is totally inconsistent with the factors that lead a utility to invest in baseload plant.[574]

431. Mr. Schedin claimed that his methodology was supported by the NARUC manual's description of the production stacking method. However, upon examination, the NARUC manual's example of the production stacking method resulted in 89.72 percent of the production plant being classified as energy related and only 10.28 percent as demand related.[575] That is the reverse of the results Mr. Schedin obtained under the breakeven methodology.

432. MCC asserts that the approved methodology approved in the *1994 Minnesota Power Rate Case* is equivalent to the breakeven methodology.[576] In that docket, Minnesota Power used a combination of methodologies that included a variant of the average and excess demand method, a capital substitution (CAPSUB), and an average and excess demand/probability of deficiency model (A&E/POD). The A&E/POD method uses average demand as the focus, not the peak demand used by Mr. Schedin.[577] In addition, the Department proposed using the stratification method for classifying power supply production costs as demand- and energy-related in the *1994 Minnesota Power Rate Case*. In that matter, the Commission found that both studies were adequate because the results of both studies were very similar.[578] OTP contends that the methodology used in the Minnesota Power matter must have been significantly different from the breakeven methodology proposed by the MCC in this current case in order for Minnesota Power's and the Department's stratification results to have been similar.[579]

433. OTP has demonstrated that equivalent peaker methodology should be approved for use in this case.

D. Declining Block Rates.

434. Declining block rates are a pricing mechanism that affords a lower rate for electricity consumption above a set threshold. Multiple thresholds (blocks) can be used in the rate design for a single class. In its initial filing, OTP proposed eliminating declining block rate structures from all but four of its rates. For those remaining four rates, OTP proposed a substantial reduction in the declining block rate features by reducing the number of thresholds in those classes.

435. The Department recommended eliminating all declining block rates. MCC opposed eliminating the declining block rate structure for rates within the LGS rate class.

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[573] Ex. 61, Schedin Direct at 16.
[574] Ex. 30, Parmesano Rebuttal at 13.
[575] Tr. V. 3 at 152, Schedin; and Ex. 67.
[576] MCC Brief at 8.
[577] Electric Utility Cost Allocation Manual, January 1992, Chapter 4, page 49.
[578] *1994 Minnesota Power Rate Case*, Docket No. E-15/GR-94-001, at 51 (Findings of Fact, Conclusions of Law, and Order issued November 22, 1994)
[579] *Id.* at 51-52.

436. In response to the Department's recommendation, OTP agreed to continue phasing out declining block rates by supporting the elimination of the declining block features from two of the remaining four rates: the General Service 20 kW and Greater and Large General Service (LGS) rates. OTP's revised proposal retains declining block rates for only the following rates: Residential and General Service under 20 kW.[580] For these two rates, the declining block rate features have been substantially reduced, and OTP indicated that these declining block rates will be proposed for elimination in OTP's next general rate case.

437. Eliminating all declining block rate structures would satisfy several of OTP's rate structure objectives, such as the objectives to reflect marginal costs, promote efficient use of resources and conservation. OTP contends that these objectives should be balanced with the objectives of maintaining reasonable rate continuity and avoiding large bill impacts associated with rate design changes ("rate shock").[581]

438. OTP's approach is less abrupt than the Department's, offering a more moderated approach that would smooth the transition to more economically efficient rates and mitigate to some extent the rate impacts associated with this rate design change.[582]

439. MCC's proposal that the LGS rate continue to include a declining load factor block rate structure, is based on its view that the rate is "reflective of two or three shift manufacturing operations" which use energy during off-peak, nighttime hours when the cost of energy is low.[583] OTP responded that this argument confuses declining block rate structures with time-of-use (or load factor) rate structures. OTP maintained that the load factor block structure is an inadequate substitute for time-of-use pricing and can result in inefficient price signals.[584] OTP offered evidence that its customers do not exhibit a systematic decrease in their peak share of energy use or systematic increase in their off-peak and shoulder shares of energy use as the monthly load factor increases. Therefore, load factor blocks are not necessary to reflect higher off-peak use by higher load-factor customers.[585]

440. OTP noted that customers with relatively high off-peak and shoulder-period consumption with the ability to change their load patterns to use a larger percentage in off-peak and shoulder periods also have the ability to switch to the LGS-TOD rate, which appropriately charges customers based on their actual peak, shoulder and off-peak loads.[586]

441. OTP has demonstrated valid reasons for retaining declining block rate features in the Residential and General Service less than 20 kW rates. Similarly, OTP has shown that LGS rate class does not require retention of the declining block features to achieve the pricing goals set out above. The rates within the LGS rate class should not include declining block features.

E. Residential Customer Charge.

442. Customer billings are typically comprised of a monthly customer charge, paid by any customer connected to a utility's system, and usage charges for the electricity consumed. The monthly customer charges are set by class and may differ by zones within a utility's service area. OTP's existing urban Residential Customer Charge is $6.15 and the rural rate is $7.15. OTP

[580] Ex. 41, Prazak Rebuttal at 5.
[581] Ex. 32, Parmesano Surrebuttal at 23.
[582] *Id*.
[583] Ex. 60, Schedin Direct at 6.
[584] Ex. 32, Parmesano Surrebuttal at 4.
[585] *Id*. at 8.
[586] *Id*.

proposed increasing the Residential Customer Charge to $8.00 for both urban and rural customers. The Department supports an $8.00 customer charge, with an increase to $8.50 in two years.[587] The OAG recommends retaining the $6.15 rate and lowering the rural rate to $6.15.[588]

443. As noted by the Department, OTP's marginal cost of providing residential customer service is $11.83.[589] Because the customer charge is below the customer cost, it is necessary to recover the unrecovered customer costs through the energy charge. As a result, customers with more than average usage pay more than their proportionate share of these costs.[590] OTP maintains that this constitutes an intra-class subsidy that is inconsistent in application. Minn. Minn. Stat. § § 216B.03, provides in part:

> Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of customers.

444. The proposed increase in the Residential Customer Charge is offered by OTP as a means of addressing this inconsistent application.

445. Mr. Lindell objected to the proposed increase in the Residential Customer Charge. He maintained that the increase amounts to 28% over the existing charge and that such an amount would cause rate shock. OTP responded that an increase of less than $2 after 20 years of no change in the customer charge does not qualify as rate shock.[591] OTP noted that the customer charge is only one component of the overall bill. OTP maintained that heavier usage customers are the most affected by a rate case increase.[592] Those customers are least affected by a change in the Residential Customer Charge.

446. OTP noted that a higher customer charge improves the recovery of fixed costs. By contrast, when fixed costs are recovered through a volumetric charge, changes in the weather result in either an over- or under-recovery.

447. The OAG maintained that any increase in the customer charge contravenes the directive in Minn. Minn. Stat. § § 216B.03 to promote conservation.[593] OTP contended that this statutory provision, in effect since 1974, has never been interpreted as precluding reasonable increases in the customer charge. OTP contends that recovering less than $2.00 per customer per month through the monthly customer charge is unlikely to have a significant impact on customer's incentive to conserve energy. OTP considered a conservation response to be far more likely to result in response to the overall bill increase resulting from this proceeding.

448. The OAG relies on the Commission's decision in the *2004 CenterPoint Energy Rate Case*, which rejected an $8.00 customer charge, in part, based on the desire to promote conservation.[594] OTP maintained that the Commission's decision was influenced by CenterPoint Energy's proposal of a 60 percent increase in the customer charge. The Commission instead

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587 Ex. 86, Griffing Direct at 30.
588 Tr. V. 4 at 158, Lindell.
589 Ex. 86, Griffing Direct at 29.
590 *Id.* at 115.
591 Ex. 41, Prazak Rebuttal at 6.
592 Ex. 38, Prazak Direct at 15, Table 1.
593 OAG Brief at 10.
594 *Id.* at 12-13 (quoting from the Commission's Order Accepting and Modifying Settlement and Requiring Compliance Filing, *ITMO an Application by CenterPoint Energy Minnegasco, for Authority to Increase Natural Gas rate,* Docket No. G008/GR-04-901 (June 8, 2005) ("*2004 CenterPoint Energy Rate Case*")).

approved a $1.50 (30 percent) increase to $6.50. OTP noted that the Commission approved an increase in the customer charge for Xcel Energy to $8.00, which constituted an increase of $1.50 from $6.50. In setting out its reasoning for the Xcel award, the Commission stated in part:

> The customer charge has two main functions, one practical and one grounded in ratemaking policy. Its practical function is to help stabilize utility revenues and reduce the risk that the utility will over- or under- recover its revenue requirement due to weather-related fluctuations in gas usage and sales. Its ratemaking function is to ensure that each customer bears responsibility for a certain level of the Company's fixed costs regardless of usage.[595]

After acknowledging that Residential customer charges cause customer dissatisfaction, the Commission went on to state:

> [C]ustomer charges play an important role in the rate structure. They reduce utilities' capital costs by ensuring baseline levels of revenue, thereby reducing consumers' rates. They help mitigate rate volatility between seasons by recovering some fixed costs during the low-usage, summer months. They promote equity by ensuring that the rate structure does not shift the full system-costs imposed by low-usage and seasonal customers to normal-usage, high-usage, and year-round customers.[596]

449. While OTP did not oppose increasing the rate to $8.50 in this proceeding, OTP objects to the Department's proposal to increase that rate outside of a rate case in two years. An increase to $8.50 would move the Residential Customer Charge closer to marginal costs and is consistent with OTP's rate design objectives. However, if the increase does not occur as part of the current proceeding, OTP would prefer to wait until its next rate case, which it anticipates filing within three years, when it would have an updated marginal cost study to assist in determining the appropriate rate.[597]

450. OTP has demonstrated that an increase in the Residential customer charge to $8.00 appropriately assigns costs to that class, while not resulting in customer confusion or rate shock.

F. LGS Rate Design.

451. OTP proposed in its initial filing that the large general service (LGS) rate retain a simplified declining energy block structure.

452. At the urging of the Department, OTP revised its proposal to eliminate the declining energy block rate structure from the LGS rate. Even in OTP's original proposal, the recommended demand charges of the LGS rate had no blocking and were set at approximately the same percentage of marginal cost reflected in the weighted average energy charge (about 75%). This approach preserved the marginal cost relationship between energy and demand charges in an effort to produce the most efficient rate signals possible.

453. OTP's proposed rate eliminated any ratchet for billing demand in order to improve the transparency of the price signal and to make it easier for customers to determine how changes in their use in any given hour will affect their bills.

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[595] *2004 Xcel Energy Natural Gas Rate Case,* at 6 (Commission Order Accepting and Modifying Settlement and Requiring Compliance Filings issued August 11, 2005).
[596] *Id.* at 7.
[597] Ex. 41, Prazak Rebuttal at 5-6.

454. OTP's proposed rate includes a facilities charge that varies by size of secondary customer (in terms of maximum annual kW) and varies by voltage level. These charges are approximately half of marginal cost. There is no customer charge, but the minimum bill is set at the sum of $350 (approximately marginal customer cost) and the facilities charges.[598]

455. The MCC challenged the LGS rate design with respect to the rate's use of marginal costs and with respect to the elimination of the declining energy block.

1. Use of Marginal Costs in LGS Design.

456. OTP's Proposed LGS rate design is based upon marginal energy and capacity costs.

457. The MCC criticisms of OTP's use of marginal costs in the design of the LGS rate are largely based on a number of errors in their understanding of the rate.[599] Their largest objection relates to the mistaken belief that OTP included capacity costs as part of energy costs in the rate and greatly understated the value of capacity costs.[600] Those criticisms confuse marginal cost-based rate design principals and embedded cost-based rate design principals.[601]

458. Shifting from an embedded cost rate structure to a marginal cost rate structure necessarily implies changing the relationships between energy and demand charges in order to provide customers with more efficient price signals.[602] These features of the LGS rate (and all OTP rates) are reflective of OTP's objective to move to marginal cost-based rates. Marginal cost-based rates satisfy several rate design objectives including efficiency of price signals and promotion of conservation.

2. Elimination of Declining Energy Block from LGS Rate.

459. The MCC argues that the declining block should be retained in the LGS rate in order to create an incentive for customers to operate during non-peak periods.[603]

460. The declining energy block rate structure is not a reasonable approximation of time-of-use pricing.[604] Furthermore, OTP's LGS customers do not exhibit a systematic decrease in their peak share of energy use or systematic increase in their off-peak and shoulder shares of energy use as monthly load factor increases. Therefore, MCC's assumption that load factor blocks are necessary to reflect higher off-peak use by high load factor customers is incorrect,[605] and the suggestion that the LGS rate should retain the declining energy block is not recommended.

G. OTP's Proposed LGS-TOD Rate Design.

461. OTP's proposed LGS-TOD rate makes several improvements to OTP's existing rate: it reflects a four-month summer/eight-month winter seasonal pattern of costs; it includes three diurnal periods; and it reflects OTP's marginal costs. [606] The seasonal change has not been challenged by any party.

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[598] Ex. 29, Parmesano Direct Testimony at 19-20 & Schedule 1 at 31-32.
[599] Ex. 30, Parmesano Rebuttal at 23-26.
[600] *Id*.
[601] *Id*.
[602] Ex. 30, Parmesano Rebuttal at 25-26.
[603] Ex. 61, Schedin Rebuttal at 6.
[604] Ex. 32, Parmesano Surrebuttal at 4-6.
[605] *Id*. at 8.
[606] The existing rate uses the name "Large General Service—Time of Use" (or "LGS—TOU").

462. Based on its criticism of OTP's marginal cost study, Enbridge proposed that no change be made to OTP's existing Time of Day Rider.[607] The foregoing discussion on the appropriateness of OTP's marginal cost methodology addresses this criticism.

463. The MCC recommended redesigning the LGS-TOD rate to: (1) base voltage level energy discounts on loss differentials; (2) base voltage level demand discounts on fixed embedded costs associated with each level of service; (3) use higher demand charges to signal known future investment in Big Stone II and transmission expansion; and (4) base the remaining revenue to be collected from energy charges (after accounting for an appropriate level of demand charges) on a marginal energy cost analysis using actual embedded cost data.

464. OTP contended that the first two steps in this design are based on an assumption that customers served at different voltage levels within a class should pay different rates. Because such distinctions in transmission voltage are inappropriate, as discussed in the Transmission portion of these Findings, these two steps in redesigning the LGS-TOD rate are inappropriate. The third step implicitly assumes that capacity costs should be based on the future cost of the Big Stone II project rather than based on the market cost of capacity during the period rates will be in effect. Because OTP's marginal cost study methodology was appropriate, it would be inappropriate to redesign the LGS-TOD rate on this basis. The fourth step is based on the prior three steps, and is therefore also inappropriate. The MCC redesign proposals should not be adopted.

465. The MCC recommendation bases one rate component (demand charges) on the cost of future capacity additions, and another component (energy charges) on current marginal costs. This approach is likely to result in an inefficient signal to consume more energy in all hours except the hour in which the customer set its billing demand.[608]

466. The MCC and Enbridge objected to OTP's proposed LGS-TOD's three diurnal pricing periods: peak, shoulder and off-peak. The current LGS-TOU rate has just two diurnal periods: peak and off-peak. The MCC opposes the move to three diurnal periods claiming that customers may have trouble keeping track of the various periods.

467. OTP noted that only three customers take service under this rate. OTP considered customer confusion implausible because these customers have experts managing their energy use. These managers are in frequent contact with OTP senior Industrial Services Engineers.[609]

468. Enbridge criticizes the change in periods not because of complexity, but because they are different from other utilities from which Enbridge Energy takes service and, therefore, they are concerned that this difference may complicate load management across Enbridge's multi-state pipeline.[610] The comparison rates provided by Enbridge do not reveal great differences among the OTP's proposed periods and the periods of the comparison utilities.[611]

469. Enbridge also recommended that holidays all be treated as off-peak, but OTP's analysis of holidays showed that high loads on OTP's system can occur on holidays, and, therefore, treating them as off-peak would not be consistent with actual consumption patterns.[612]

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[607] Tr. V. 4 at 14.
[608] Ex. 30, Parmesano Rebuttal at 27.
[609] Ex. 32, Parmesano Surrebuttal 29.
[610] Ex. 69, Erickson Direct at 20-21.
[611] Ex. 30, Parmesano Rebuttal at 31-32.
[612] Ex. 30, Parmesano Rebuttal at 3.

470. Because the periods are based on OTP's actual costs of service, they should not be changed. OTP's proposed LGS-TOD rate should be accepted without modification.

H. Standby Service Rate Design.

471. OTP proposed a Standby Service rate which fundamentally reflects its current Standby Service offering and is based upon the rate design for the proposed LGS-TOD rate.[613] The proposed changes to the Standby Service rate (like the LGS-TOD rate) reflect updated seasonal and costing periods and are based upon OTP's marginal costs.

472. The MCC maintained that the proposed additions to the Standby rate are "very complicated" compared to OTP's current rate.[614] OTP contends that the only changes proposed are the addition of one diurnal energy charge (shoulder) and the addition of seasonality to the demand charges (summer and winter).[615] OTP maintains that these proposed additions improve the price signals inherent in the rate and reflect the similar changes that have been made to the LGS-TOD rate.

473. OTP maintains that those customers likely to take service under the Standby Service rate will have no difficulty understanding these additional features.[616] The nature of the rate requires that customers be sophisticated in energy matters as they will necessarily have on-site generation. These customers will likely be business owners with a fair level of business sophistication.[617]

474. MCC asserted that OTP's current Standby Service rate structure should be retained. OTP objected to this proposal. The pricing structure of the proposed Standby Service mirrors many features contained in OTP's proposed LGS-TOD rate. OTP argued that the relationship to the proposed LGS-TOD rate is consistent with the relationship between the current Standby Service Tariff and the current LGS-TOU rate.[618] OTP described the proposed changes as merely reflecting updated seasonal and costing periods and are based on marginal costs, which improve the overall efficiency of the rates.[619]

475. Additionally, MCC argued that Standby Service customers should be allowed to choose their supplemental service rate rather than being required to take supplemental service under the LGS-TOD rate. OTP contended that this would not be appropriate due to the rate design. The existing LGS-TOU rate and the Standby Service rate were created in coordination with one another.[620] This practice of prescribing the LGS-TOU as supplementary service under the Standby Service rate has been in effect since 1993.[621] No compelling reason has been offered to support changing these rates.

476. MCC recommended that a "sub-transmission" voltage level be added to the Standby Service rate schedule. For the reasons described in the transmission section of these findings, no such modification should be made.

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613 Ex. 41, Prazak Rebuttal at 12.
614 Ex. 60, Schedin Direct at 46.
615 Ex. 41, Prazak Rebuttal at 10.
616 Otter Tail currently has no customers taking service under its Standby Service rate.
617 Ex. 41, Prazak Rebuttal at 10-11.
618 *Id*. at 12.
619 *Id*.
620 *Id*. at 13.
621 *Id*.

I. Ag-Processing Rider Proposed By MCC.

477. MCC claims that OTP should be required to design and offer a special AG Processing rider similar to that offered by Minnkota Power Cooperative.[622] OTP contended that such a rate would be redundant with rates it already offers. [623] OTP noted that its LGS rider has wide flexibility. OTP and an Ag-Processing customer (or a customer from any industry) could design a customer-specific rate, which would include a load management component and other customer-specific features.[624] Because OTP's proposed LGS rider already provides an adequate vehicle for customizing a load management rate and provides better flexibility than adopting a rate design of another utility as MCC proposes, a specific Ag-processing rate is not needed.[625]

478. If OTP were required to offer an Agri-Processing Rider, it would need to be designed based on cost information specific to OTP. The MCC's proposed interruptible rate for Ag-Processing loads has an inconsistency between the interruptible rate charges and the limits on interruptions.[626] In recent years, OTP typically has controlled customers on its interruptible riders in the range of 200 to 400 hours per season.[627] The MCC AG Processing proposal would limit interruptions to 100 total hours per season.[628] Unless customers on such a rate are interruptible for as many hours as OTP has non-zero marginal generation, transmission, and distribution substation/trunk feeder costs, it would not be appropriate to eliminate all generation, transmission and distribution substation/feeder capacity costs from the demand charges. [629] Such a rate design would result in a subsidy by other customers.[630]

479. For these reasons, OTP should not be required to offer an AG Processing rider as recommended by MCC. OTP should be required to work with appropriate customers under its LGS Rider to design interruptible rates that are appropriate for those individual customers.

J. Proposed Revisions to OTP's Tariff.

480. OTP and MCC arrived at a mutual agreement on changes that should be made to OTP's proposed tariff book. No party opposed their agreement. Based upon that agreement and the record, OTP's proposed tariff language should be modified as follows (shown in strike/underline format):

> 97. **Section 1.02 APPLICATION FOR SERVICE** shall be revised to read as follows:
>
> Anyone desiring electric service from the Company must make application to the Company before commencing the use of the Company's service. The Company reserves the right to require an Electric Service Agreement before the service will be furnished. Receipt of electric service shall constitute the receiver a Customer of the Company subject to its rates, rules and regulations, whether service is based upon the Tariff, an Electric Service Agreement, or otherwise. All applications and contracts for service shall be made in the legal name of the party desiring service. The

[622] MCC Init. Brief at 29-30.
[623] Ex. 43, Prazak Surrebuttal at 5.
[624] *Id*.
[625] *Id*.
[626] Ex. 32, Parmesano Surrebuttal at 12.
[627] *Id*.
[628] *Id*.
[629] *Id*. at 12-13.
[630] *Id*.

Customer will be responsible for payment of all services furnished.

A Customer may take service pursuant to any Commission-approved rate(s) for which the Customer qualifies. The Customer shall be required to take service under the selected rate(s) for a minimum of one (1) year, unless the Customer desires to change its service to any rate offering that is newly approved within the one-year period and for which the Customer qualifies. If a Customer changes its service to a different rate, the Customer shall not be permitted to change back to the originally applicable rate for a period of one (1) year. A Customer shall provide the Company at least 45 days prior notice in the event of any requested change.

~~Unless otherwise agreed to by the Company because of Customer hardship, a Customer shall be required to obtain service from the Company under the service Tariff that has been determined to be applicable for that Customer at that service location, for a minimum period of one (1) year. If a Customer changes the provision of service to a different service Tariff that is applicable to the Customer at that location, the Customer shall not be permitted to change back to the originally applicable service Tariff for a period of one (1) year.~~

98. The First Paragraph of **SECTION 3.02 CURTAILMENT OR INTERRUPTION OF SERVICE** shall be revised to read as follows:[631]

The Company may curtail or interrupt service without notice to any or all of its Customers when in the Company's judgment such curtailment or interruption will tend to prevent or alleviate a threat to the integrity of its electrical system or whenever requested to do so by any regional Reliability authority. If, in the Company's judgment, curtailment or interruption of service to some but not all of the Company's Customers is warranted by the circumstances, the Company shall select the Customers to be curtailed or interrupted. The Company shall have no liability for any reason whatsoever resulting from any curtailment or interruption made pursuant to this paragraph. Any curtailment or interruption of service to the Customer will not relieve the Customer's obligations to the Company. Upon request from any Customer, Company shall make reasonable effort to provide notice to such Customer of a projected curtailment or interruption in service, in the event Company has advance notice of curtailment or interruption of such Customer's service. However, Company shall have no liability to Customer or to any third party for Company's failure to give such notice, or for erroneously or mistakenly giving such notice.

99. **SECTION 4.14 COMBINED METERING** shall be added as follows:

Combined Metering is defined as the addition of multiple service or metering points so that the energy and demand is registered on one meter. This results in coincident demand for these loads, thus treating it as one larger load for billing one rate. To quality for Combined Metering a Customer must be served at a premises consisting of contiguous property with the same occupant and each service entrance to be combined must have a minimum entrance rating of 750 kVA (750 kVa entrance at various voltages which is equivalent to: 900 amps @ 277/480; 1800 amps @ 120/240 delta; 2100 amps @ 120/208 wye). Combined Metering can be accomplished with hardware or software totalizers or by installing primary metering.

[631] The second paragraph of Section 3.02 shall remain as originally proposed.

The Company will, in its sole discretion, reasonably determine whether to use primary metering or totalizing for any particular Customer that qualifies for Combined Metering.

100. **SECTION 5.01 EXTENSION RULES AND MINIMUM REVENUE GUARANTEE** shall be revised to read as follows:

The Company will, at its own expense, extend, enlarge, or change its Distribution or other facilities for supplying electric service when the anticipated revenue from the sale of additional service at the location justifies the expenditure. If it reasonably appears to the Company that the expenditure may not be justified based on a three-year projection of revenue received from the Customer's applicable rate(s) (not including any such amounts expected to be recovered through the fuel adjustment rider, but including any base costs of energy included in the Customer's rate(s)), the Company may require the Customer to (a) sign an Electric Service Agreement guaranteeing a minimum payment of no less than three (3) years use of electric service, or (b) ~~such other period of service as may be justified by the Company, or to~~ require the Customer to make payment in advance in the event the Company determines on a commercially reasonable basis that the Customer may not maintain adequate creditworthiness over the period or may fail to make payments for service over the period.

The Company shall provide to the Customer an estimate with detail of the costs prior to construction.

If at the point of true-up at the end of the agreed to initial period of service, the Customer uses and pays for more than the specified amount of electric service, (not including any such amounts paid pursuant to the fuel clause adjustment rider, but including any amounts paid for the base costs of energy included in the Customer's rate(s)), ~~excluding that portion representing fuel cost recovery,~~ any advance that may have been made will be refunded to the Customer together with interest at the rate provided for Customer deposits under Minn. Rule 7820.4500. However, if the Customer uses less than the guaranteed minimum, the amount of the deficiency will be billed to the Customer. ~~, and/or will be deducted from the Customer's advance payment, and the balance of the advance payment, if any, will be refunded to the Customer, with interest on the balance~~.

101. The Fifth Paragraph, the Seventh Paragraph, and the Final Paragraph contained within **SECTION 5.02 SPECIAL FACILITIES** shall be revised to read as follows:[632]

'Excess Expenditure' is defined as the total reasonable incremental cost above that of Standard Facilities, for construction of Special Facilities, including: the value of the un-depreciated life of existing facilities being removed and removal costs less salvage; the fully allocated incremental labor costs for design, surveying, engineering, construction, administration, operations or any other activity associated with the project; the incremental easement or other land costs incurred by the Company; the incremental costs of immediately required changes to associated

[632] The second, fourth and fifth paragraphs of the definition of "Excess Expenditure" shall remain as originally proposed.

electric facilities, including backup facilities, to ensure Reliability, structural integrity and operational integrity of electric system; the incremental taxes associated with requested or ordered Special Facilities; the incremental cost represented by accelerated replacement cost if the Special Facility has a materially shorter life expectancy than the standard installation; the incremental material cost for all items associated with the construction, less salvage value of removed facilities, and any other prudent costs incurred by Company directly related to the applicable Special Facilities.

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Common examples of Special Facilities include duplicate service facilities, special switching equipment, special service voltage, three phase service where single phase service is reasonably determined by the Company to be adequate, excess Capacity, Capacity for intermittent equipment, trailer park Distribution systems, underground installations, conversion from overhead to underground service, specific area or other special undergrounding, location and relocation or replacement of existing Company facilities. Payments required will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a requesting or ordering party shall not change the Company's ownership interest or rights. Payment for Excess Expenditures associated with Special Facilities may be required by either, or a combination, of the following methods as prescribed by the Company: a single charge for the Excess Expenditures incurred or to be incurred by the Company due to such a special installation, or a monthly charge being one twelfth of Company's annual fixed costs associated with the Excess Expenditures necessary to provide such special installation. The monthly charge will be discontinued if the Special Facilities are removed or if the requester eventually qualifies for the originally requested Special Facilities as Standard Facilities. The Company shall provide to the Customer an estimate with detail of the costs prior to construction.

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Special Facilities Payments

Where the requesting or ordering Customer ~~party~~ is required to prepay or agrees to prepay or arrange payment for Special Facilities, the requesting or ordering Customer ~~party~~ shall execute an agreement or service form pertaining to the installation, operation and maintenance, and payment for the Special Facilities. ~~Payments required will be made on a non-refundable basis and may be required in advance of construction unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a requesting or ordering party shall not change the Company's ownership interest or rights. Payment for Special Facilities may be required by either, or a combination, of the following methods as prescribed by the Company: a single charge for the costs incurred or to be incurred by the Company due to such a special installation, or a monthly charge being one-twelfth of Company's annual fixed costs necessary to provide such special installation. The monthly charge will be discontinued if the Special Facilities are removed or if the~~

~~requester eventually qualifies for the originally requested Special Facilities as Standard Facilities~~.

102. **SECTION 7.02 MODIFICATION OF RATES, RULES AND REGULATIONS** shall be revised to read as follows:

The Company reserves the right~~, in any manner permitted by law,~~ to modify any of its rates, rules, and regulations or other provisions now or hereafter in effect, in any manner permitted by law. Customers shall be provided with notice of any such modification as required by Minnesota Law and Commission Rules.

103. The Availability Provision Contained in **SECTION 10.03 LARGE GENERAL SERVICE,** shall be revised to read as follows:

AVAILABILITY: This schedule is applicable ~~available~~ to non-residential ~~customers having a load factor high enough to justify its application~~. This rate is not applicable for energy for resale, nor for municipal outdoor lighting. Standby Service will be supplied only as allowed by law.

481. No other modifications to OTP's proposed rate book should be made. The tariff language should be accepted as proposed with the above-referenced modifications.

XXIII. RESOLVED ISSUES

A. Removal Of Big Stone I Acquisition Adjustment From Rate Recovery.

482. In its Application, OTP included the acquisition adjustment for Big Stone I in its rate base. Ms. Campbell recommended that the unamortized balance remaining in rate base be removed. The Company agreed to the rate base adjustment in the amount of $245,833 removing the remaining unamortized balance of the Big Stone I acquisition adjustment from rate base. In addition, Ms. Campbell recommended removing the annual amortization, in the amount of $25,407, from expenses in the 2006 test year. The Company agrees these adjustments are appropriate because the annual amortization included in base rates in OTP's 1986 rate case has allowed OTP to recover the acquisition adjustment cost.[633]

B. Recognition of Refund from Docket E,G-999/AA-06-1208.

483. In her Direct Testimony, Ms. Campbell proposed to reduce the base cost of energy to reflect the Commission's ordered refund in Docket E,G/AA-06-1208 ("1208 Order"), which had not been issued when the Company filed its Application. The refunded amount in the 1208 Order is $682,982.[634] Ms. Campbell noted that this is an adjustment to both retail revenue and production expense, with a net impact to base rates of zero. OTP agreed to include this in the calculation of its base cost of energy, which will be filed as part of its compliance with the final order in this case.[635]

[633] Ex. 95, Campbell Revised Direct at 39-42 and NAC-18; Ex. 36, Brutlag Rebuttal at 2-3.
[634] Ex. 99, Lusti Direct (DVL-7).
[635] Ex. 95, Campbell Direct at 43-44, Ex. 22, Beithon Rebuttal at 19.

C. Accumulated Depreciation Reserve Related To 2007 Depreciation Rates.

484. In his Direct Testimony, Mr. Lusti noted that the Company needed to increase its depreciation reserve to equal the increase in depreciation expense of $636,397. OTP had included the increase in depreciation expense in its Application.[636] OTP agreed this is an appropriate adjustment to increase the accumulated depreciation reserve balance to match the depreciation expense adjustment.[637]

D. Big Stone Pollution Control Equipment/Depreciation Reserve Related To Big Stone I.

485. In its January 14, 2008, Errata filing, OTP increased the depreciation expense by $58,816, which decreased the Operating Income by $58,816 to $280,604, reflecting the 2006 depreciation expense related to Big Stone I. The Department offered no objections.[638]

E. Sales Forecast.

486. OTP forecasted its revenue for the test year as $132,630,146. The Department forecasted a revenue amount of $133,870,903. The difference in these forecasts was significantly reduced through the application of various adjustments. OTP agreed to the Department's adjustments to increase Retail Revenue and Production Expense by $342,732 and $296,140, respectively.[639]

F. Advertising Expense.

487. The Company and the Department agreed to disallow 8 of 31 advertisements that had been classified as safety advertisements because the 8 ads did not appear to promote electrical safety. OTP and the Department further agreed that the Minnesota advertising expense amount, not the system amount, should be used in calculating the adjustment to 2006 test year advertising expense. This produced an adjustment of $19,228 to OTP 2006 test year advertising expenses.[640]

G. CIP Expenses.

488. OTP's Application reflected $1,518,011 in CIP expenses for the 2006 test year. The Department testified that OTP's proposed test-year CIP expenses were too low and recommended increasing the expense by $247,389, which would bring OTP's CIP expenses to its approved 2006 budget of $1,765,400. OTP concurs with this adjustment.[641]

H. Cash Working Capital.

489. In its Application, OTP included the cash working capital requirements for operation, maintenance, and other expenses. OTP applied lead/lag study factors to its test-year O&M expenses to determine its cash working capital requirement. After analysis, the Department

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[636] The difference between the Commission approved rates in the depreciation studies for 2005, Docket No. E-017/D-05-1410, and for 2006, Docket No. E-017/D-06-1238.
[637] Ex. 99, Lusti Direct at 7-8 and DVL-9; and Ex. 36, Brutlag Rebuttal at 1-2.
[638] Ex. 21, OTP Errata Filing at 1; and Ex. 108, Lusti Hearing Statement, Attachment DVL-H-4(d).
[639] Ex. 104, Heinen Hearing Statement; Tr. V. 4 at 202; Ex. 108, Lusti Hearing Statement, Attachment DVL-H-7, Column (p).
[640] Ex. 84, Davis Surrebuttal at 1-2; and Ex. 22, Beithon Rebuttal at 35-36.
[641] Ex. 82, Davis Direct at 16-18; and Ex. 22, Beithon Rebuttal at 38.

determined that these lead/lag factors were reasonable. The Parties agree that the lead/lag study cash working capital calculations will need to be adjusted to reflect all of the changes to revenue requirements as finally determined by the Commission.[642]

I. Interest Synchronization.

490. In the calculation of OTP's federal and state income tax expenses for this proceeding, the applicable interest deduction, also known as interest synchronization, was calculated. The calculation was made using the weighted cost of debt capital multiplied by the average rate base. The Department agrees with this method of calculation. The Parties are agreed that the interest synchronization calculation will need to be recalculated when the final rate adjustments approved by the Commission are known.[643]

J. Power Services Incentive Compensation.

491. OTP and the Department have agreed to accept the Department's recommendation to apply a 25% cap to the sum of the Power Service Incentive. That application of the cap decreases the test-year operating expense by $408,540.[644]

K. Uncontested Financial Related Issues.

492. The Company filed testimony as part of its Application on a number of matters including: (1) Interest on Customer Deposits; (2) Tree Trimming and Vegetation Maintenance; (3) Storm Repairs; (4) Injuries and Damages; and (5) Research Expenses. No other party filed testimony on these issues.

XXIV. CONCLUSIONS.

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Ch. 216B and section 14.50.

2. Any foregoing Finding which contains material which should be treated as a Conclusion is hereby adopted as a Conclusion.

3. OTP has shown that the issues that have been resolved result in rates that are in the public interest and those issues should be approved by the Commission.

4. OTP has not shown that its proposed capital structure accurately reflects an appropriate division of debt and equity. The Department's proposed capital structure does reflect an appropriate division of debt and equity and should be adopted in calculating required revenue.

5. OTP has not demonstrated that its proposed return on equity (ROE) strikes an appropriate balance between the interests of shareholders and ratepayers. The Department has demonstrated that its methodology to compute the ROE is better justified, and that methodology

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[642] Ex. 99, Lusti Direct at 9-10; Ex. 102, Lusti Surrebuttal at 17; Ex. 34, Brutlag Direct at 29-31; and Ex. 36, Brutlag Rebuttal at 2.

[643] Ex. 99, Lusti Direct at 34; Ex. 102, Lusti Surrebuttal at 17-18; Ex. 20, Beithon Direct at 25-26; and Ex. 22, Beithon Rebuttal at 19.

[644] Ex. 108, Lusti Hearing Statement, DVL-7, column (q); and Ex. 27, Wasberg Surrebuttal at 4, and Exhibit_(PEW-3), Schedule 1.

should be adopted in this matter. The ROE figure of 10.91 percent is appropriate and should be used to determine the allowable ROR in this matter.

6. With adoption of the Department's proposed capital structure, OTP's appropriate allowable ROR is 8.57 percent for rate setting purposes.

7. The proposed changes in tariff provisions are reasonable and should be approved.

8. OTP has demonstrated that the deferred Schedule 16 and 17 costs of $292,895 are appropriate for recovery.

9. For asset based margins, the fixed sharing margin credit of $5.009 million to the rate base requirement as proposed by OTP and the Department is reasonable.

10. OTP's proposed payment of 10 percent of its non-asset based margins to the ratepayers by passing those margins through the fuel clause results in reasonable rates. No credit to the rate base is required. The proposal of OTP and the Department that 80% of any ASM margins be paid to ratepayers through the FCA is reasonable and should be adopted.

11. OTP has demonstrated that its incentive compensation methodology and amounts are reasonable. The Department has demonstrated that a tracking mechanism for actual amounts paid and a refund of unpaid incentive compensation already included in rates is reasonable and should be adopted.

12. The Department has demonstrated that OTP's proposed FAS 106 Transition Costs are not appropriate for inclusion because OTP did not file a rate case or other request to establish an amortization account for FAS 106 Transition Costs within in three years of the Commission's Order Adopting Accounting Standard and OTP's FAS 106 Transition Costs were recorded in 1993. No increase to the rate base is appropriate, since these costs have not been addressed by the Commission.

13. OTP has demonstrated that its benefit costs calculation of $19,277,539 for the test year is reasonable and should be adopted.

14. OTP has demonstrated that its proposed alternative general allocator methodology results in an equitable distribution of costs. OTP's methodology satisfies the Commission's standards of similarity and being in the public interest for the use of an alternative methodology to the 1008 Docket general allocator.

15. OTP has demonstrated that its proposed economic development program is cost effective and that one-hundred percent of those costs are properly included in the test year revenue requirements.

16. OTP's request for rate case expenses in this matter is appropriate, and those expenses should be amortized over a three-year period, subject to crediting a deferral account for rate case expenses recovered beyond the three year period for application to future rate case expenses.

17. OTP has demonstrated that its charitable contributions are recoverable pursuant to Minnesota Statute § 216B.16, subd. 9, and that its organizational dues meet the Commission requirements for inclusion in OTP's proposed revenue requirement.

18. OTP has demonstrated that its DSM programs meet the Commission's standards inclusion in OTP's proposed revenue requirement.

19. Use of the year ending on ending December 31, 2006, as the projected test year for determining OTP's revenue requirement is reasonable. The forecast of the total of OTP's electricity sales, agreed to by both the Department and OTP, for the test year is reasonable. Calculation of the net required revenue adjustment is dependent upon the determination of the various issues before the Commission in this proceeding.

20. The allocation of costs by jurisdiction and by demand, as proposed by OTP, is reasonable and should be adopted for rate setting purposes. The use of "rolled-in" rates has been shown to be appropriate for OTP's customers.

21. OTP's projected test year rate base is appropriately adjusted by the Department's D2 modifications, reducing OTP's transmission plant and accumulated depreciation balances for the Minnesota jurisdiction by $22,440,375 and $8,714,703, respectively and reducing the Minnesota jurisdictional portion of OTP's transmission expense by $1,322,463.

22. OTP has demonstrated that it will experience a substantial revenue shortfall. OTP is entitled to recover this revenue shortfall through an adjustment of its electric rates to increase its revenues.

23. OTP has demonstrated that its proposed allocation of the rate increase across customer classes meets the Commission's standards for rate design and does not result in rate shock. OTP's reduction of declining block rates, while retaining block rate elements for two customer classes, strikes the best balance between the various rate design principles of the Commission.

24. OTP has demonstrated that an increase in the residential basic charge from $6.15 per month to $8.00 per month is an appropriate adjustment to balance the need to recoup the costs of serving the residential class of customers without interclass subsidies, with the need to encourage conservation, avoid rate shock, and account for other factors between rate classes.

25. Modifying OTP's electric rates in the manner described in the Findings and Conclusions above results in just and reasonable rates that are in the public interest within the meaning of Minn. Stat. § 216B.11.

26. The rate finally ordered by the Commission should be compared to the interim rate set in the Commission's November 27, 2007 Order Setting Interim Rates, and a refund be ordered to the extent that the interim rate exceeds the final rate, subject to any true-up ordered regarding any particular expense.

Based on the foregoing Findings and Conclusions above, the Administrative Law Judge makes the following:

XXV. RECOMMENDATION.

IT IS RECOMMENDED that the Public Utilities Commission order that:

1. Otter Tail Power is entitled to increase gross annual revenues in the manner and in an amount consistent with the terms of this Order.

2. Within 30 days of the service date of this Order, Otter Tail Power shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning with the effective date of the new rates, and the rate design decisions contained herein. Otter Tail Power shall include proposed customer notices explaining the final rates. Parties shall have 14 days to comment.

3. (If the Commission orders an Interim Rate Refund) within 30 days of the service date of this Order, Otter Tail Power shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein. Parties shall have 14 days to comment.

Dated: June 17, 2008

s/Steve M. Mihalchick
STEVE M. MIHALCHICK
Administrative Law Judge

Reported: Shaddix and Associates
Transcripts Prepared (Seven Volumes)

MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS

600 North Robert Street
Saint Paul, Minnesota 55101

Mailing Address:
P.O. Box 64620
St. Paul, Minnesota 55164-0620

Voice: (651) 361-7900
TTY: (651) 361-7878
Fax: (651) 361-7936

June 17, 2008

See Attached Service List

Re: ***In the Matter of the Application of Otter Tail Corporation d/b/a/ Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota***
OAH 12-2500-19336-2
MPUC E-017/GR-07-1178

Dear Parties:

The documents listed below have been filed with the E-Docket system and served as specified on the attached service list.

Findings of Fact, Conclusions and Recommendation
Service List as of 6/17/08

Sincerely,

s/Steve M. Mihalchick

STEVE M. MIHALCHICK
Administrative Law Judge

Telephone: (651) 361-7844
steve.mihalchick@state.mn.us

SMM:dsc
Enclosures

MPUC Docket No. E-017/GR-07-1178
OAH Docket No. 12-2500-19336-2

ALJ's SERVICE LIST as of January 7, 2008

Re: In the Matter of Otter Tail Corporation d/b/a Otter Tail Power Company's Application for Authority to Increase Rates for Electric Service in Minnesota

Serve one copy of the document or item, unless otherwise indicated, on the following persons. If you E-File a document on the PUC E-Filing system, persons with the E-File notation (**EF**) below need not be served a paper copy, unless otherwise indicated.

The Honorable Steve M. Mihalchick
Office Of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55164-0620
(Paper original or copy)

Burl W. Haar
Minnesota Public Utilities Commission
121 East Seventh Place, Suite 350
St. Paul, MN 55101-2147
(**EF** or 15 paper copies)

Sharon Ferguson
MN Department of Commerce
85 7th Place E. Suite 500
St. Paul, MN 55101-2198
(**EF** or 4 paper copies)

Michael J. Bradley
Moss & Barnett
90 South Seventh Street
4800 Wells Fargo Center
Minneapolis, MN 55402

Richard J. Johnson
Moss & Barnett
4800 Wells Fargo Center
90 South Seventh Street
Minneapolis, MN 55402

Bruce Gerhardson
Otter Tail Corporation
215 South Cascade Street
P.O. Box 496, Fergus Falls,
Minnesota 56538-0496

Ron Spangler, Jr.
Otter Tail Power Company
215 South Cascade Street
P.O. Box 496, Fergus Falls,
Minnesota 56538-0496

Karen Finstad Hammel
Assistant Attorney General
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Valerie Means
Assistant Attorney General
1400 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

Ronald M. Giteck
Assistant Attorney General
900 Bremer Tower
445 Minnesota Street
St. Paul, MN 55101-2131

William Stamets
Assistant Attorney General
445 Minnesota St, Suite 900
St. Paul, MN 55101-2127

Clark Kaml
445 Minnesota St, Suite 900
St. Paul, MN 55101-2127

Richard J. Savelkoul
Felhaber Larson Fenlon & Vogt
444 Cedar Street
Suite 2100
St. Paul, Minnesota 55101-2136

Bill Blazar
Minnesota Chamber of Commerce
400 Robert St. N. Suite 1500
St. Paul, MN 55101

Mike Franklin
Minnesota Chamber of Commerce
400 Robert St. N. Suite 1500
St. Paul, MN 55101

Andrew P. Moratzka
Mackall Crounse & Moore, PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402-2859

Gary Chestnut
Ag Processing, Inc.
P.O. Box 2047
Omaha, NE 68103-2047

William L. Glahn
Piedmont Consulting, Inc.
701 4th Avenue South, Suite 500
Minneapolis, MN 55415

Larry L. Schedin PE
LLS Resources, LLC
1137 Plymouth Building
12 South Sixth Street
Minneapolis MN 55402

James D. Larson
Dahlen, Berg Consulting, Inc.
200 S. Sixth Street, Suite 300
Minneapolis, MN 55402

Christopher D. Anderson
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

Marcia Podratz
Minnesota Power
30 West Superior Street
Duluth, MN 55802-2093

Michael C. Krikava
Briggs and Morgan, P.A.
2200 IDS Center
80 South 8th St
Minneapolis, MN 55402

Thomas Erik Bailey
Briggs and Morgan, P.A.
2200 IDS Center
80 South 8th St
Minneapolis, MN 55402

SaGonna Thompson
Xcel Energy
414 Nicollet Mall – 7th Floor
Minneapolis, MN 55401-1993

Robert S. Lee
Mackall, Crounse & Moore, PLC
1400 AT&T Tower
901 Marquette Avenue
Minneapolis, MN 55402

Shane Henriksen
Enbridge Energy Limited Partnership
119 North 25th Street East
Superior, WI 54880-5247

James C. Erickson
Kelly Bay Consulting
17 Quechee
Superior, WI 54880

James M. Nessa
UTILITY RESEARCH LLC
6424 Walrath Circle
Ashtabula, OH 44004

Jonathan M. Drews
UTILITY RESEARCH LLC
P. O. Box 230
Fergus Falls, MN 56538-0230

Patrick J. Mastel, Staff Attorney
Missouri River Energy Services
PO Box 88920
Sioux Falls, SD 57109-8920

Annette Henkel
Minnesota Utility Investors
400 Robert Street North
St. Paul, MN 55101

In addition to E-filing or paper service, electronic copies should also be e-mailed to the following persons:

apm@mcmlaw.com
bgerhardson@ottertail.com
bill.stamets@state.mn.us
bradleym@moss-barnett.com
burl.haar@state.mn.us
canderson@allete.com
clark.kaml@state.mn.us
jdrews@utilityresearchllc.com
jericksonkbc@gmail.com
jnessa@utilityresearchllc.com
johnsonr@moss-barnett.com
jshaddix@janetshaddix.com
karen.hammel@state.mn.us
mkrikava@briggs.com
mpodratz@mnpower.com
mui@mnutilityinvestors.org
pmastel@mrenergy.com
ron.giteck@state.mn.us
rsavelkoul@felhaber.com
rlspangler@otpco.com
rsl@mcmlaw.com
sagonna.thompson@xcelenergy.com
shane.henriksen@enbridge.com
steve.mihalchick@state.mn.us
stuart.mitchell@state.mn.us
tbailey@briggs.com
valerie.means@state.mn.us

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
ADMINISTRATIVE LAW SECTION
600 NORTH ROBERT STREET
PO BOX 64620
ST. PAUL, MINNESOTA 55164-0620

CERTIFICATE OF SERVICE

In the Matter of the Application of Otter Tail Corporation d/b/a/ Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota	OAH 12-2500-19336-2 PUC E-017/GR-07-1178

Denise S. Collins, certifies that on the 17th day of June, 2008, she served a true and correct copy of the attached **Findings of Fact, Conclusions and Recommendation** by serving as specified on the attached service list, addressed to the following individuals:

Burl W. Haar
Executive Secretary
MN Public Utilities Commission
350 Metro Square Building
121 Seventh Place E
St. Paul, MN 55101

Attached service list