that in DENC's next update of its depreciation study it should account for its projected CCR remediation and closure costs in the decommissioning expenses for its coal-fired power plants.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 59-62

The evidence supporting these findings of fact and conclusions is contained in the direct testimony of Public Staff witness Lucas, and the Post-Hearing Exhibits of DENC.

In his testimony, witness Lucas explained that the Public Staff investigated whether the Company has environmental or general liability insurance that would provide coverage for its CCR-related costs, and that the Public Staff reviewed notices, claims, and related documents sent by the Company to insurers that relate to CCR. Tr. vol. 6, 196. Based on the Public Staff's review, witness Lucas recommended that the Commission monitor the Company's existing and potential insurance claims. He stated that if any insurance proceeds are ultimately received or recovered, the Commission should require that the Company place all such proceeds into a regulatory liability account to either be disbursed back to ratepayers or to offset the costs to ratepayers of the Company's CCR-related costs. *Id.* at 197.

DENC's Confidential Post-Hearing Exhibit No. 2, filed herein on October 23, 2019, includes the details of the potential insurance policy recoveries related to possible CCR liabilities of DENC.

Discussion and Conclusions

To the extent that ratepayers are required to pay the costs of CCR remediation, and DENC's insurance policies cover some of those costs, ratepayers should receive all or a portion of the insurance proceeds. In that regard, DENC is representing the interests of its ratepayers in pursuing the insurance claims. Therefore, the Commission finds it appropriate to hold DENC to the same standard of care that DENC is required to exercise in providing electric service. That standard is one of reasonableness and prudence. In subsequent proceedings, if the parties or the Commission raise meritorious issues about DENC's representation of the interests of ratepayers in the insurance claims, DENC shall bear the burden of proving that it exercised reasonable care and made prudent efforts to obtain the maximum recovery from the insurance claims.

Further, the Commission concludes that DENC should be required to place all insurance proceeds received or recovered by DENC in the insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. In addition, the regulatory liability account shall accrue a carrying charge at the overall rate of return authorized for DENC in this Order.

Finally, based on the risk sharing allocation of CCR costs adopted by the Commission, DENC is entitled to retain a percentage of the CCR insurance proceeds equal to the above weighted average equity capital financing.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 63

The evidence supporting this finding of fact and these conclusions is contained in the findings and conclusions of the Commission herein pertaining to authorized cost deferrals by DENC.

In the present case, the Commission is approving DENC's post-in-service costs of the Greensville CC and recovery through amortization of a previously deferred portion of DENC's CCR costs. The Commission notes that a deferred cost is not the same as the other cost of service expenses recovered in the Company's non-fuel base rates. A deferred cost is an exception to the general principle that the Company's current cost of service expenses should be recovered as part of the Company's current revenues. When the Commission approves a typical cost of service, such as salaries and depreciation expense, there is a reasonable expectation that the expense will continue at essentially the same level until the Company's next general rate case, at which time it will be reset. On the other hand, when the Commission approves a deferred cost the Commission identifies a specific amount that has already been incurred by the Company, or, in the case of CCR costs, is estimated to be incurred by the Company. In addition, the Commission sets the recovery of the amount over a specific period of time. Further, the Company is directed to record the recovery of the specific amount in a regulatory asset account, rather than a general revenue account. If DENC continues to recover that deferred cost for a longer period of time than the amortization period approved by the Commission that does not mean that DENC is then entitled to convert those deferred costs into general revenue and record them in its general revenue accounts. Rather, the Company should continue to record all amounts recovered as deferred costs in the specific regulatory asset account established for those deferred costs until the Company's next general rate case.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 64-65

The evidence supporting these findings of fact and conclusions is contained in the DENC's verified Application and Form E-1, the testimony and exhibits of the witnesses, the Public Staff Stipulation, and the entire record in this proceeding.

Summary of the Evidence

In the Application and initial direct testimony and exhibits, DENC provided evidence supporting an increase of approximately $27 million in its annual non-fuel revenues from its North Carolina retail electric operations. With regard to fuel, in his direct testimony Company witness McLeod testified that the Company annualized fuel clause revenue by applying the current base fuel rate plus Rider A to the annualized and normalized customer usage at June 30, 2019. Witness McLeod also explained that an adjustment was made to fuel clause expense to make fuel clause expense equal to fuel clause revenue, net of the regulatory fee. Tr. vol. 4, 260.

On August 5, 2019, the Company filed supplemental direct testimony and exhibits updating several cost of service adjustments. These updated adjustments decreased the Company's revenue requirement by approximately $2.1 million, for a revised increase in North Carolina retail revenue of $24.9 million, which was reduced again in the Company's additional supplemental testimony filed on September 12, 2019, to $24.2 million.

On August 23, 2019, the Public Staff filed the direct testimony of witness Johnson, presenting her recommended accounting and ratemaking adjustments to the Company's proposed revenue requirement. Accounting for these adjustments, she recommended a decrease in the Company's annual base non-fuel operating revenue of $8,112,000. Witness Johnson also testified that the Public Staff adjusted the fuel clause expense to reflect the base fuel rate and Rider A as set forth in the Additional Supplemental Testimony of DENC witness Haynes and recommended by Public Staff witness Jack Floyd, subject to the outcome of the Company's currently ongoing fuel proceeding in Docket No. E-22, Sub 579. Witness Johnson stated that this adjustment resulted in a decrease of $2.155 million from the fuel expense originally included in the Company's Application. Tr. vol. 6, 39.

On September 17, 2019, the Company and the Public Staff entered into and filed the Public Staff Stipulation. Also on September 17, 2019, the Company filed the testimony of witnesses McLeod, Miller, Hevert, Davis, and Haynes in support of the stipulated revenue increase. These witnesses testified in support of the accounting and ratemaking adjustments agreed upon in the Public Staff Stipulation. They also testified that the Public Staff Stipulation is the result of negotiations between the Stipulating Parties. Also on September 17, 2019, the Public Staff filed the Joint Stipulation testimony of witnesses Johnson and McLawhorn, recommending and supporting the stipulated adjustments to the Company's requested revenue increase while also noting the unresolved issues related to CCRs.

The Public Staff Stipulation, as shown on Settlement Exhibit I, reflects the Company's proposed increase in the revenue requirement of $6.428 million, consisting of an increase of $8.583 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues, and the Public Staff's proposed increase in the revenue requirement of $2.037 million, consisting of an increase in $4.192 million in non-fuel revenues and a decrease of $2.155 million in base fuel revenues. The difference between the Company's and the Public Staff's proposals in the Public Staff Stipulation result from the unresolved issues identified at Section II.A.i of the Public Staff Stipulation (cost recovery of the Company's CCR costs, the recovery amortization period, and return during the amortization period).

Discussion and Conclusions

As discussed in the body of this Order, the Commission approves the Public Staff Stipulation, with the exception of section VII.A, and makes its individual rulings on the unresolved issues as discussed herein. As the unresolved issues pertaining to CCR cost recovery, and the Commission's decision in this Order on the conversion costs at Chesterfield Units 3 and 4, were not addressed by the Public Staff Stipulation and accompanying testimony and exhibits, the Commission requests that DENC recalculate the required annual revenue requirement consistent with all of the Commission's findings and rulings herein as soon as practicable following the issuance of this Order. The Commission further orders DENC to work with the Public Staff to verify the accuracy of the recalculations. Once the Commission receives this filing, the Commission will work promptly to verify the calculations and will issue an order with final revenue requirement numbers. DENC should provide electronic copies of this filing to the Commission, complete with formulas intact.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 66

The evidence supporting this finding of fact and these conclusions is contained in the verified Application, the testimony and exhibits of the DENC and Public Staff witnesses, the Public Staff Stipulation, and the record as a whole.

Pursuant to N.C.G.S. § 62-133(a), as described earlier, the Commission is required to set rates that are "fair both to the public utilities and to the consumer." In order to strike this balance between the utility and its customers, the Commission must consider, among other factors: (1) the utility's reasonable and prudent cost of property used and useful in providing adequate, safe and reliable service to ratepayers, and (2) a rate of return on the utility's rate base that is both fair to ratepayers and provides an opportunity for the utility through sound management to attract sufficient capital to maintain its financial strength. N.C.G.S. § 62-133(b). DENC's continued operation as a safe, adequate, and reliable source of electric service for its customers is vitally important to DENC's individual customers, as well as to the communities and businesses served by DENC. DENC presented credible and substantial evidence of its need for increased capital investment to, among other things, maintain and increase the reliability of its system and comply with environmental requirements.

For example, DENC witness Mitchell testified that during the last three years, the Company invested $1.3 billion to bring online a total of 1,588 MW of new generation in the Greensville County CC. Witness Mitchell stated that this new generation is cleaner and highly-efficient combined cycle generating capacity that has the potential to create substantial fuel savings due to very favorable current natural gas prices. Witness Mitchell also noted that the Company has invested $132 million to bring on-line three regulated solar facilities totaling 56 MW and between 2019 and 2020 plans to invest approximately $410 million to bring on-line an additional 240 MW of nameplate solar capacity. Witness Mitchell also testified that the Company has received a certificate of public convenience and necessity to construct the 12 MW Coastal Virginia Offshore Wind Project that is expected to come on-line in 2020. Finally, witness Mitchell explained that the Virginia Grid Modernization and Security Act specified that up to 5,000 MW of solar and wind generation facilities constructed by a utility such as the Company are in the public interest and the Company has committed to have approximate 3,000 MW placed in service or under development by the end of 2022. Tr. vol. 6, 171-72.

Witness Mitchell further testified that DENC has spent approximately $268 million on transmission improvements in North Carolina during the last three years. He stated that these improvements support improved reliability of the transmission system and local economic growth. He also testified that the Company plans to invest an additional $200 million in transmission improvements in North Carolina over the next five years. Tr. vol. 6, 173-74.

In addition, witness Mitchell testified that DENC has invested over $29 million in its distribution system in North Carolina during the last three years. He stated that these investments balance the need for reliable service with prudent spending. *Id.*

Witness Mitchell also testified regarding the impact of current and proposed environmental regulations on the Company's operations. He stated that during the last decade electric utilities have been required to address compliance with a suite of new environmental standards adopted by the EPA. He testified that compliance with these standards has directly impacted DENC's operation of its coal-fired generating plants, citing as an example the EPA's Mercury Air Toxics Standards Rule, which led to the retirement of over 900 MW of coal-fired generating capacity. Witness Mitchell also stated that the enactment of the CCR Rule in April 2015 created a legal obligation for the Company to retrofit or close all of its inactive and existing ash ponds, as well as perform required monitoring, corrective action, and post-closure activities as necessary. *Id.* at 170-76.

Moreover, witness Mitchell testified that DENC plans to invest $11.1 billion over the next three years for generation, transmission, and distribution investments in order for the Company to continue to fulfill its obligations of providing reliable, cost-effective service in an environmentally responsible manner for DENC's customers. *Id.* at 177.

These are representative examples of the capital investments that have been made and are planned to be made by DENC in order to continue providing safe, reliable, and efficient electric service to its customers. Based on all of the evidence, the Commission finds and concludes that the rates established herein strike the appropriate balance between the interests of DENC's customers in receiving safe, reliable, and efficient electric service at the lowest possible rates, and the interests of DENC in maintaining the Company's financial strength at a level that enables the Company to attract sufficient capital. As a result, the Commission concludes that the rates established by this Order are just and reasonable under the requirements of N.C.G.S. § 62-130, et seq.

IT IS, THEREFORE, ORDERED as follows:

1. That the Stipulation filed by DENC and the Public Staff is hereby approved, with the exception of Section VII.A;

2. That DENC shall consult with the Public Staff in accordance with the directive in the body of this Order, and shall remove from its revenue requirement and rate base all North Carolina retail jurisdictional costs and effects arising from the wet to dry CCR conversion project for Units 3 and 4 of the Chesterfield Power Station;

3. That the Stipulation filed by DENC and CIGFUR is hereby approved in its entirety;

4. That DENC shall recover from its North Carolina retail ratepayers its CCR Costs incurred during the period July 1, 2016, through June 30, 2019;

5. That the Company's CCR Costs shall be amortized and recovered from ratepayers over a ten-year period;

6. That during the amortization and recovery of the CCR Costs the CCR costs shall not earn a return;

7. That DENC shall be allowed to recover its financing costs incurred during the Deferral Period and up to the effective date of new rates approved in this Order, at the Company's previously authorized weighted average cost of capital;

8. That the Company shall use annual compounding for calculating the financing costs deferred costs during the Deferral Period;

9. That DENC shall maintain complete records of all environmental management activity and test results that pertain to its coal ash management program, and make such records available to the Public Staff and the Commission upon request and in the format that is reasonably requested by the Public Staff and the Commission;

10. That as soon as practicable following the issuance of this Order DENC shall file with the Commission the annual revenue requirement and accompanying rate schedules and terms and conditions that are consistent with the findings and conclusions of this Order and the Public Staff Stipulation, with the exception of Section VII.A. The Company shall work with the Public Staff to verify the accuracy of the filing. Further, DENC shall file schedules summarizing the gross revenue and the rate of return that the Company should have the opportunity to achieve based on the Commission's findings and determinations in this proceeding;

11. That DENC is hereby authorized to adjust its rates and charges in accordance with the findings in this Order effective for service rendered on and after the

following day after the Commission issues an Order accepting the calculations required by Ordering Paragraph No. 10;

12. That the Commission shall issue an order as soon as reasonably practicable approving the final revenue requirement numbers once received from DENC and verified by the Public Staff;

13. That the proper jurisdictional average base fuel factor for this proceeding is 2.089¢/kWh, excluding regulatory fee, and 2.092¢/kWh, including regulatory fee. The Company shall replace the voltage-differentiated base fuel factors approved in Sub 532 with the following voltage-differentiated base fuel factors, including regulatory fee, effective February 1, 2020:

Customer Class	Base Fuel Factor
Residential	2.118 ¢/kWh
SGS & PA	2.115 ¢/kWh
LGS	2.098 ¢/kWh
NS	2.036 ¢/kWh
6VP	2.065 ¢/kWh
Outdoor Lighting	2.118 ¢/kWh
Traffic	2.118 ¢/kWh

14. That the jurisdictional and class cost allocation, rate design principles, and service regulations proposed by the Company, and agreed upon in the Public Staff Stipulation, are approved and shall be implemented;

15. That DENC shall implement Rider EDIT as described in Section VIII of the Public Staff Stipulation. Further, although not specifically outlined in the Public Staff Stipulation, it is appropriate that in this proceeding DENC's fully-adjusted cost of service includes the income tax benefit arising from the annual amortization of federal protected EDIT during the test year, thereby incorporating a going-level of federal protected EDIT amortization per the IRC's normalization rules in base non-fuel rates;

16. That as soon as practicable after the date of this Order, DENC shall file for Commission approval five copies of rate schedules designed to comply with the rate design approved in this Order accompanied by calculations showing the revenues that

will be produced by the rates for each schedule. This shall include a schedule comparing the revenue produced by the filed schedules during the test period with the revenue that will be produced under the rate schedules to be approved herein and a schedule illustrating the rates of return by class based on the revenues produced by the rates for each schedule;[27]

17. That as soon as practicable after the issuance of the last Commission Order in DENC's four pending rate-related proceedings, which are this proceeding, the Sub 579 fuel charge adjustment proceeding, the Sub 578 renewable energy and energy efficiency portfolio standard (REPS) cost recovery proceeding, and the Sub 577 demand-side management (DSM) proceeding, DENC shall file a consolidated proposed customer notice addressing the rate changes associated with the non-fuel base and base fuel rate changes approved in this proceeding (Sub 562), the Fuel Rider B in the Sub 579 proceeding, the REPS Rider RP and RPE rate changes in Sub 578, and the DSM Rider C and Rider CE rate changes in Sub 577. Such notice shall include the effect of each rate-related proceeding on a residential customer using 1,000 kWh and the combined effect of all four rate-related proceedings on a residential customer using 1,000 kWh. Upon approval by the Commission, DENC shall notify its North Carolina retail customers of the foregoing rate adjustments by including the approved notice as a bill insert with customer bills rendered during the next regular scheduled billing cycle;

18. That the Company shall continue to annually file a cost of service study with the Commission using the Summer/Winter Peak and Average methodology;

19. That in its next general rate case, the Company shall file the results of a class cost of service study with production and transmission costs allocated on the basis of the Summer/Winter Coincident Peak method in addition to the SWPA used in this proceeding and consider such results for the sole purpose of apportionment of the change in revenue to the customer classes;

20. That if DENC receives revenue for any deferred cost for a longer period of time than the amortization period approved by the Commission for that deferred cost, the Company shall continue to record all revenue received for that deferred cost in the specific regulatory asset account established for that deferred cost until the Company's next general rate case;

21. That the Company shall work with CIGFUR to consider whether certain provisions within its RTP rates should be modified and, if there is mutual agreement between CIGFUR and DENC to such modifications, and CIGFUR indicates that at least one of its member customers is willing to take service under such rates, DENC shall re-

[27] If necessary, the Commission will address in a subsequent order any refund due ratepayers based on any differences in the rates approved in this Order and the Company's temporary rates implemented on November 1, 2019.

file such rates with the Commission for approval with the modifications agreed upon within 60 days of such agreement;

22. That within ten days of the resolution by settlement, judgment, or otherwise of the pending and future CCR insurance claims, DENC shall file a report with the Commission explaining the result and stating the amount of insurance proceeds to be received or recovered by DENC. This reporting requirement shall apply even if there is litigation appealed to a higher court;

23. That DENC shall place all CCR insurance proceeds received or recovered by DENC from pending and future insurance claims in a regulatory liability account and hold such proceeds until the Commission enters an order directing DENC as to the appropriate disbursement of the proceeds. The regulatory liability account shall accrue a carrying charge at the net-of-tax overall rate of return authorized for DENC in this Order; and

24. That in DENC's next update of its depreciation study it shall account for its projected CCR waste management facility decommissioning and closure costs in the decommissioning expenses for its coal-fired power plants.

ISSUED BY ORDER OF THE COMMISSION.

This the 24th day of February, 2020.

NORTH CAROLINA UTILITIES COMMISSION

Kimberley A. Campbell

Kimberley A. Campbell, Chief Clerk

Commissioner Daniel G. Clodfelter concurs in part and dissents in part.

DOCKET NO. E-22, SUB 562
DOCKET NO. E-22, SUB 566

Commissioner Daniel G. Clodfelter concurring in part and dissenting in part:

I concur in the result reached by the Commission on all issues save two, and as to those two matters I dissent. In addition, though I join in the outcome on all other matters, some of my thinking on those matters is not fully captured by the Commission's opinion and order, and I write to elaborate my views on certain issues. I address first the two points on which I would reach a different result.

Rate Design and Fixed Monthly Charge

For the reasons set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), which I will not repeat here, I do not support the Company's proposal to increase the fixed monthly charge to residential customers and would find the proposal unsupported on this record. My view, as set out in my dissent in the DEC Rate Order, is that the Company's fixed monthly charge should be calculated with reference to cost allocation that employs the "basic customer method" to assign distribution system costs, but in any event the Company's current fixed charge, which relies in part on the "minimum system method" for allocating distribution system costs, should not be increased from its current level. (For a calculation of the results of using the "basic customer method" of cost allocation, see Company's Rate Allocation and Rate Design Late-Filed Exhibit 1.) Accordingly, I dissent as to Finding Number 40 approving the Company's proposed rate design, and therefore also as to Finding Number 66, wherein the Commission finds the Company's proposed rates, except as modified by the Commission's order, to be just and reasonable. I also take note of and agree with Finding Number 15.I., in which the Commission finds that "... some customers [of the Company] will struggle to pay their utility bills under the rate increases authorized herein." I believe this finding counsels against increasing the fixed portion of the Company's rates at this time.

Allowance of Financing Costs During Deferral Period

As to the second point, I dissent from Finding Number 54 and would instead find that the Company is not entitled to recover any amount greater than the approximately $19.2 million actually expended for costs related to waste coal ash during the Deferral Period. More specifically, I would not allow recovery of the approximately $2.7 million the Company has requested as alleged "financing costs" related to the actual $19.2 million in expenditures.[28]

The Commission has determined, and I agree, that neither the Actual CCR Expenditures nor the Deferral Period Return are entitled to earn any return during the

[28] The Commission's order defines the capitalized term "CCR Costs" to include both the $19.2 million in actual expenditures on activities related to coal ash and also the sum of $2.7 million labelled

period of amortization and will not be included in rate base. (Finding No. 53) Much of my reasons for supporting this result are set forth in my dissent in the DEC Rate Order in Docket No. E-7, Sub 1146 (June 22, 2018), and again I will not repeat them here. With respect to the allowance of what the Commission calls "financing costs," however, I can find no supportable basis for differentiating the Deferral Period from the amortization period.

The Commission proffers only one reason for this different treatment.[29] It states:

> …[T]he Commission observes that such a return *may* reduce the incentive for the Company to apply for rate increases more frequently to avoid regulatory lag. While recovering financing costs incurred during the Deferral Period does not help with the Company's short-term cash flow, it means the Company ultimately does not experience lost financing costs if it delays a new rate case.

Order at 135 (emphasis added).

I am unpersuaded by this suggestion because I do not find in the record sufficient evidence that the potential "may" is more likely than not to translate to an actual "will." I find nothing in the evidentiary record that the amount of the Deferral Period Return – approximately $2.7 million – is sufficient to drive the Company's future decisions about whether or not to seek an adjustment of the rates approved in this proceeding. On the record in this case, it is far, far more likely that the timing of future rate change applications will be driven by the planned capital investments identified by Company witness Mitchell and discussed by the Commission in its analysis in support of Finding No. 66 – e.g., the Company's commitment to place into service 3,000 MW of new solar and wind generation capacity by 2022 (Tr. vol. 6, 171-72), the Company's plans to spend some $200 million in transmission upgrades in North Carolina over the next five years (Tr. vol. 6, 173-74), and the Company's overall plan to invest some $11.1 billion in the aggregate in generation, transmission, and distribution system improvements over the next three years. *Id.* at 177. It is expenditures such as these that will determine when the Company next seeks a change in its rates and not whether it is allowed in this case to

"financing costs." The term "financing costs" is a euphemism for the authorized weighted average cost of capital, which includes the costs of third-party debt but also a return on equity. For clarity, hereafter I will refer to the first component as "Actual CCR Expenditures" and the second component as "Deferral Period Return."

[29] The Commission's order also notes that the Public Staff did not oppose allowing recovering of financing costs during the Deferral Period. This I consider a statement of fact concerning a party's position in the case; it is not a rationale justifying the Commission's decision. The Commission is not constrained by the Public Staff's position; indeed, in this case the Commission has declined to accept the settlement position of the Public Staff concerning the ratemaking treatment of certain costs for the dry ash conversion project as related to Chesterfield Units 3 and 4. Irrespective of the Public Staff's or any other party's position on an issue, the Commission is required to consider all of the evidence and exercise its independent judgment to set just and reasonable rates. *State ex rel. Utilities Commission v. Carolina Utility Customers Ass'n, Inc.*, 348 N.C. 452, 466, 500 S.E.2d 693, 703 (1998).

recover $2.7 million on account of monies already expended on coal ash remediation and closure activities over the three years prior to this case. *Id.* at 177.[30]

Beyond this, I find it difficult to harmonize the Commission's decision on this point with Findings of Fact Nos. 56 through 58 and the discussion and analysis supporting those findings, which I fully endorse and support. The Commission has found that in analyzing, proposing, and seeking the establishment of rates that included allowances for depreciation associated with its coal-fired generating units the Company failed to include any amounts for the costs of final remediation or closure of the waste ash management units associated with these plants. Had the Company done so, then at least some portion, if not all, of the costs for which it now seeks recovery, including the Actual CCR Expenditures for the Deferral Period, would have been recovered as an annual operating expense as part of the rates applicable to service provided in earlier periods.[31] Put differently, had the Company properly anticipated, estimated, and collected as part of depreciation allowance amounts that were later required for Actual CCR Expenditures made during the Deferral Period, it would have thereby accrued a reserve from the revenues earned under prior rates that could have been used to offset or avoid some, if not all, of the Deferral Period Return that it now seeks and that the Commission has approved. I cannot reconcile the Commission's admonishment that the Company did not properly account for or seek recovery of the Actual CCR Expenditures, as part of net salvage value included in depreciation allowance, with the Commission's acceptance of the Company's present request that it be allowed the Deferral Period Return in order to assist in managing the cash flow needs associated with its CCR remediation and closure activities.

The Limitations of Finding Number 51

I concur in the Commission's Finding Number 51. I do so as much because of what is not said in that finding as what is said. The Commission does not in this case find and conclude that the Company – over a period of many years and at multiple sites – prudently

[30] In this proceeding the Commission authorizes recovery of the Deferral Period Return on a backward-looking basis. It is interesting that neither the Company's stipulation and settlement with the Public Staff in its 2016 general rate case, Docket No. E-22 sub 532, nor the Commission's order in that case discussed the issue of recovery of "financing costs" for expenditures made on CCR remediation and facility closure after June 30, 2016, and during the period prior to the Company's next succeeding general rate case, now the present case. Apparently, in 2016 the Company was willing to go forward to its next rate case with no assurance that it would be able to recover its "carrying costs" on CCR expenditures made in the interim period. Approximately three years elapsed from that time until the present case, and on the present record I am unable to conclude that the timing of the present case was dictated by the "carrying cost" of CCR expenditures instead of by other factors. It is far more likely that the timing of the present case was influenced by the Company's desire to bring the new $1.3 billion Greensville combined cycle plant into rate base.

[31] As noted in the Commission's discussion of the issue, the point here is not that the Company was tasked with perfect foresight as to its ultimate, actual CCR remediation and facility closure costs but instead that it made no reasonable effort to make any estimate of such costs or recover any such estimate as part of depreciation allowances. Had it done so, the cash flow impact of some portion, if not all, of the Actual CCR Expenditures would have been covered by the revenues recorded to recover depreciation expense.

managed waste coal ash. It finds only that the particular items of expenditure for which recovery is sought in this case cannot be causally connected to specifically identifiable imprudent acts or omissions based on the record evidence presented to the Commission. The expenditures at issue in this case would likely have been incurred in all events upon final closure of the waste ash management units. They involved activities such as characterizing the wastes, calculating volumes, preliminary design and engineering of closure plans, legal review and vetting of closure plans, permitting and regulatory oversight activities, water sampling and monitoring, and dewatering and consolidating ash for ultimate disposal. (Although the total cost of these activities is included in DENC's testimony as public information, the separate cost of each activity was filed by DENC under seal as a proprietary trade secret in Confidential Company Late-Filed Exhibits 5 and 6, and Supplemental Late-Filed Exhibit 5). The Public Staff presented no evidence that either the specific activities at issue or the amount of the costs expended were causally related to any acts or omissions that could on the present record be found to be imprudent.

The Commission's order thus preserves for the future certain questions that were not fully explored in the present case. One example of such a question, which I offer for purposes of illustration only, concerns the Company's failure to take prompt steps to permanently stabilize and close the surface impoundments at the Possum Point plant after the plant was converted to natural gas in 2003 and the impoundments ceased receiving coal ash waste. In light of the Company's knowledge of possible groundwater degradation associated with these impoundments (*See* Tr. vol. 6, 145-157), it may be pertinent to examine in greater detail the Company's failure to take action to permanently close the impoundments in 2003 and whether or not the delay in commencing final closure activities until after adoption of the CCR Rule can be causally linked to any subsequent remedial or closure costs that could have been avoided if earlier action had been taken. The parties differ greatly as to the standard of conduct that should be applied in evaluating the Company's actions and omissions at Possum Point in 2003 and prior to the adoption of the CCR Rule, but it is not necessary to decide this point in the present proceeding. I offer this example not to express any judgment on the matter but merely to show that the limited scope of Finding Number 51 may not be a matter of purely theoretical interest.

"Equitable Sharing" By Any Other Name ....[32]

The Commission professes to reject the Public Staff's "equitable sharing" position as being inconsistent with accepted ratemaking principles and attempts to differentiate the Public Staff's position from its own effort to strike a "fair balance" between ratepayers and shareholders.[33] Order at 136-137. I am unable to join in the Commission's reasoning

[32] "What's in a name? That which we call a rose by any other name would smell as sweet ..." *Romeo and Juliet,* Act II, Scene II.

[33] E.g. Order at 131, referring to the "well-established history" of Commission decisions seeking to establish a "fair and reasonable" balance between ratepayers and shareholders; Order at 132, referring to the objective of striking "the appropriate balance between shareholder and customer interests to set just and reasonable rates"; and Order at 135, noting that the ten-year period of amortization approved by the

for the straightforward reason that the ultimate result reached by the Commission amounts, in concept, to exactly the same thing as advocated by the Public Staff. The outcome of the Public Staff's proposal and that of the Commission's analysis differs only in the fact that the Public Staff recommended an eighteen-year period of amortization of allowed costs rather than the ten-year amortization period adopted by the Commission. Indeed, much of the reasoning offered by the Commission is the same as that invoked by the Public Staff to support its own "equitable sharing" proposal, including the Commission's reliance on the analysis and authority of, among other precedent, the MGP Order and the Anna/Surry Order. Order at 130-131.[34]

I concur with both the Commission's order and with the Public Staff that there is ample legal basis for the Commission to allocate or divide the cost burden between ratepayers and the Company's shareholders. For myself, the point of difference I have with the Public Staff is not over the concept of "equitable sharing" or the legal basis for application of that concept, but over the specific equities of this case that warrant invoking it. I find sufficient support for the result reached by the Commission in the analysis and discussion associated with Findings of Fact Numbers 56 through 58, and I do not need to go further than the scope of those findings to reach that result. The Company's failure to make any provision over the useful lives of its coal-fired generating plants for recovery of the ultimate costs of remediation and closure of waste coal ash management facilities is ample ground for the Commission to find that a portion of the costs now incurred for such remediation and closure must be borne by the Company itself and not by present and future ratepayers. The Commission's selection of a ten-year period for amortization of those costs achieves a fair and reasonable balance of cost-sharing between ratepayers and the Company.

A Question for the Future

Following promulgation of the CCR Rule, the Company's plan for closure of waste ash surface impoundments at all of its plants was to dewater the ash, place a permanent cap over the contents, and close the impoundments in place. This plan has been superseded by the adoption of Virginia Senate Bill 1355, codified at Va. Code Ann. §10.1-1402.03 (2019) (the Chesapeake Coal Ash Act) for the waste ash management units located within the Chesapeake Bay watershed. The Chesapeake Coal Ash Act applies to the coal ash management units at the Company's Bremo, Possum Point, Chesapeake and Chesterfield plants, requiring the excavation and removal of waste ash for permanent disposal outside the watershed. Company witness Williams testified that the impact of this legislation did not increase any of the costs or change any of the activities for which cost recovery is requested in this case but that the Act may likely affect

Commission "...strikes the more appropriate and fairer balance" than does the position of either the Company or the Public Staff.

[34] The Commission's reasoning that most closely parallels the Public Staff's "equitable sharing" analysis is contained in its discussion of whether the Company should be allowed to earn a return on the unamortized balance of the CCR Costs (Order at 130-134), but I consider immaterial the rubric under which the discussion is placed. I acknowledge, of course, that the Commission does not rely upon the Public Staff's notion of "culpability." With this difference, however, the analysis otherwise runs very similarly.

future impoundment closure activities and the resulting costs for which recovery will be sought in future rate cases. Tr. vol. 5, 93. I believe it is important, because the parties did not develop the issues in their evidentiary presentations or their briefing and because on this record it is not ripe for decision, that the Commission signal to the parties that two potential matters remain for determination in future rate cases: (1) whether the Company's record of management of waste coal ash, especially with respect to the surface impoundments at the four plants affected by the Chesapeake Coal Ash Act, may have prompted or contributed to the Act's elimination of the Company's preferred "cap in place" closure method and, if it did so, to what extent the costs of remediation and final closure of those waste management facilities may be increased due to requirements of the Act more stringent than those of the CCR Rule, and (2) whether or not, independently of the preceding question, any incremental or enhanced costs resulting from compliance with the Chesapeake Coal Ash Act may be recovered from North Carolina ratepayers. The first of these questions speaks to an issue of prudence; the second is jurisdictional. I express no view on either of these questions at this time, but I note that the Company and other interested parties should be prepared, in the appropriate proceeding and at the appropriate time, to present evidence concerning the amount, if any, by which the Company's coal ash remediation and waste management facility closure costs at the Bremo, Possum Point, Chesapeake, and Chesterfield plants were or have been increased, due to changes in scope or extent, over what those costs would have been had those waste management facilities been remediated and closed under the provisions of the CCR Rule.

/s/ Daniel G. Clodfelter

Commissioner Daniel G. Clodfelter

OAH 68-2500-32993
MPUC Docket No. G011/GR-15-736

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION
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OAH 68-2500-32993
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STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION**

This matter came before Administrative Law Judge Jeanne M. Cochran for an evidentiary hearing on May 23-24, 2016 in the small hearing room of the Minnesota Public Utilities Commission. Public hearings were held on March 28-30, 2016, and written comments were received until April 15, 2016. Post hearing briefs were filed on June 29, 2016, and responsive briefs were filed on July 12, 2016. The hearing record closed on July 12, 2016, following the receipt of the last responsive brief.

Elizabeth M. Brama and Kristin M. Stastny, Briggs and Morgan, P.A., appeared on behalf of the Applicant, Minnesota Energy Resources Corporation (MERC or the Company).

Julia E. Anderson, Linda S. Jensen and Peter E. Madsen, Assistant Attorneys General, appeared on behalf of the Department of Commerce, Division of Energy Resources (Department).

Ian Dobson and Joseph C. Meyer, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General, Residential Utilities and Antitrust Division (OAG).

Andrew P. Moratzka and Emma J. Fazio, Stoel Rives, LLP, appeared on behalf of Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, the Minntac and Keewatin Mines of United States Steel Corporation, and USG Interiors, Inc. (collectively appearing as the Super Large Gas Intervenors (SLGI)).

Richard J. Savelkoul, Martin & Squires, P.A., appeared on behalf of Constellation New Energy – Gas Division, LLC (Constellation).

Robert Brill, Sundra Bender, and Clark Kaml, staff of the Public Utilities Commission (PUC or Commission) also participated in the hearing.

STATEMENT OF THE ISSUES

On September 30, 2015, MERC filed an application for authority to increase its rates for natural gas service in Minnesota. Its application was filed pursuant Minn. Stat. § 216B.16, subd. 1 (2016). The Company requested an annual rate increase of approximately $14,846,380 or 5.47 percent.[1]

On November 30, 2015, the Commission issued its Notice and Order for Hearing referring the matter to the Office of Administrative Hearings for contested case proceedings.[2] The Notice and Order for Hearing set forth the following issues to be addressed by the parties:[3]

1. Is the test year revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings by the Company?

2. Is the rate design proposed by the Company reasonable?

3. Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

4. Other Revenue issues pertaining to MERC's Information Requirements Document No. 5, pages 3 and 4, including adjustments to, and reduction in, Account 495 – Other Gas Revenues.

5. If so, the extent to which the cost of system upgrades to serve the City of Rochester should be borne by all MERC ratepayers and if so, on what basis.[4]

6. Whether the test year in this case and in future MERC rate cases should be so far removed from the most recent fiscal year and whether the test year should be allowed to start more than 60 days after the filing date.

7. Other issues raised by the parties that are relevant to MERC's proposed rate increase.

[1] Exhibit (Ex.) 2, Vol. 1, Cover Letter at 1 (Application).
[2] NOTICE AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-116011-01).
[3] NOTICE AND ORDER FOR HEARING at 2 (Nov. 30, 2015) (eDocket No. 201511-116011-01).
[4] By order dated February 8, 2016, the Commission moved all Rochester Project Phase II costs and issues from the current general rate case into a new docket, MPUC Docket No. G-011/M-15-895, for separate consideration as a stand-alone contested case. *See In the Matter of a Petition by Minn. Energy Res. Corp. for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project*, MPUC Docket No. G-011/M-15-895, NOTICE AND ORDER FOR HEARING at 8 (Feb. 8, 2016).

Based on the evidence in the hearing record,[5] the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. Summary of Application

1. MERC's application to increase its natural gas rates in Minnesota requested an annual rate increase of $14,846,380, or approximately 5.47 percent. MERC's application uses a test year ending December 31, 2016 and is based on a 10.30 percent return on equity.[6]

2. MERC identified the following items as the main drivers of its proposed rate increase: increased investments in system extensions, improvements for reliability and customer service, increased operations and maintenance (O&M) expenses, and general inflation.[7]

3. Over the course of the proceeding, several of the financial issues were resolved among the parties. Based on MERC's analysis of its projected 2016 test year and adjustments agreed to during the proceeding, MERC revised its request to a rate increase of $9,966,944.[8]

4. During the course of the hearing, the Department recommended financial adjustments totaling $8,180,281 to MERC's original proposal. At the close of the evidentiary hearing, the Department recommended that MERC receive a rate increase of $6,666,099.[9]

5. The OAG also recommended a number of adjustments to MERC's proposal. The OAG did not provide a comprehensive review of MERC's application, and therefore did not provide a final recommendation on the total amount of any rate increase.[10]

II. Parties to the Proceeding

6. MERC is a local distribution company organized under the laws of the State of Delaware, authorized to do business in Minnesota, with its principal office located in Eagan, Minnesota.[11] MERC provides natural gas service to approximately 230,000 customers in 52 counties and 184 communities in Minnesota.[12]

[5] A Master Exhibit List, including links to all exhibits received into evidence, was e-filed by the court reporter on June 22, 2016 (eDocket No. 20166-122466-01).
[6] Ex. 2, Vol. 1, Notice of Change of Rates at 3 (Application).
[7] Ex. 13 at 6-7 (Kult Direct).
[8] *See* MERC's Initial Brief at 1 (June 29, 2016) (eDocket No. 20166-122788-01).
[9] Ex. 417 at MAS-S-1, MAS-S-4 (St. Pierre Surrebuttal).
[10] *See generally*, OAG's Initial Post-Hearing Brief (June 29, 2016) (eDocket No. 20166-122790-01).
[11] Ex. 13 at 4 (Kult Direct).
[12] Ex. 13 at 4 (Kult Direct).

7. MERC is a subsidiary of WEC Energy Group, Inc. (WEC).[13] MERC was previously owned by Integrys Energy Group, Inc. (Integrys). On June 29, 2015, WEC acquired Integrys and its subsidiaries, including MERC.[14] WEC is now the corporate parent of MERC and several other natural gas and electric utilities in Wisconsin, Illinois, and Michigan.[15]

8. The Department represents the public interest in rate proceedings.[16] Department staff reviews the testimony and schedules filed by the utility and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

9. The OAG represents the interests of residential and small business customers in proceedings before the Commission.[17] The OAG staff reviews the testimony and schedules filed by the Company and other parties and files testimony and argument intended to protect those interests.

10. The SLGI is comprised of some of the largest industrial customers of MERC in Minnesota. SLGI includes Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, the Minntac and Keewatin Mines of United States Steel Corporation, and USG Interiors, Inc.[18]

11. Constellation is a major, full service gas marketer. Constellation arranges for and provides its customers with gas and transportation service. A significant number of Constellation's customers are within MERC's Minnesota service territory.[19]

III. Jurisdiction

12. The Commission has general jurisdiction over MERC's rates under Minn. Stat. §§ 216B.01 and 216.03 (2016). The Commission has specific jurisdiction over the rate changes requested by the Company under Minn. Stat. § 216B.16 (2016).

13. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-.62 (2016) and Minn. R. 1400.5010-.8400 (2015).

IV. Procedural Background

14. In MERC's 2013 general rate case, the Commission's Order required MERC to file sales forecast data with the Commission at least 30 days in advance of the

[13] Ex. 13 at 4-5 (Kult Direct).
[14] Ex. 13 at 4-5 (Kult Direct).
[15] Ex. 13 at 5 (Kult Direct).
[16] *See* Minn. Stat. § 216A.07, subds. 2-3 (2016).
[17] *See* Minn. Stat. § 8.33 (2016).
[18] Petition to Intervene of SLGI at 1-3 (Dec. 11, 2015) (eDocket No. 201512-116397-01).
[19] Petition to Intervene of Constellation New Energy at 1 (Feb. 8, 2016) (eDocket No. 20162-118069-01).

filing of its next rate case.[20] On August 17, 2015, MERC filed with the Commission sales forecast data for the instant rate case.[21]

15. On September 30, 2015, MERC filed a general rate case seeking an annual rate increase of about $14,800,000, or approximately a 5.47 percent increase, together with a proposed interim rate increase of $9,827,962 or 3.62 percent to be effective on January 1, 2016.[22] The Company's filing included its direct testimony.[23]

16. On October 2, 2015, the Commission issued a notice to potentially interested parties requesting comments on whether the Commission should accept the filing as substantially complete and whether it should refer the case to the Minnesota Office of Administrative Hearings for contested case proceedings.[24] The Department, the only party that filed comments, recommended referring the matter to the Office of Administrative Hearings for a contested case proceeding.[25]

17. On October 21 and 26, 2015, MERC filed additional information on the development and costs of its new customer information service system.[26]

18. On November 30, 2015, the Commission issued three orders. First, it issued its Order Accepting Filing, Permitting Specific Salary Data to Remain Private, Extending Timelines, and Suspending Rates in which the Commission accepted MERC's rate increase petition as being in proper form and substantially complete as of September 30, 2015. The Commission also suspended the proposed rate schedule under Minn. Stat. § 216B.16, subd. 2, until the Commission issues a final determination in this case, and extended the suspension period by 90 days to October 31, 2016 due to other pending rate cases. In addition, the Commission granted MERC's request to classify the salaries of its sixth through tenth highest-paid employees as not public, private data.

19. Second, the Commission issued its Order Setting Interim Rates in which it granted, as modified, MERC's interim rate proposal to be in effect for service rendered on and after January 1, 2016.

20. Third, the Commission issued its Notice of and Order for Hearing in which it identified issues to be addressed and referred this matter to the Office of Administrative

[20] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-011/GR-13-617, FINDINGS OF FACT, CONCLUSION OF LAW AND ORDER (Oct. 28, 2014) (2013 MERC RATE CASE ORDER).
[21] Ex. 1, Sales and Customer Forecast at 1 (Initial Filing).
[22] Ex. 2, Cover Letter at 1 (Application).
[23] *See* Ex. 13 (Kult Direct); Ex. 15 (Gast Direct); Ex. 17 (Nawrot Direct); Ex. 19 (Hans Direct); Ex. 21 (Kage Direct); Ex. 25 (Kupsh Direct); Ex. 27 (John Direct); Ex. 29 (Hinkes Direct); Ex. 31 (Wilde Direct); Ex. 33 (Quick Direct); Ex. 34 (Hoffman Malueg Direct); Ex. 37 (Lee Direct); Ex. 41 (DeMerritt Direct); Ex. 47 (Hevert Direct).
[24] NOTICE OF COMMENT PERIOD ON COMPLETENESS AND PROCEDURES (Oct. 2, 2015) (eDocket No. 201510-114548-01).
[25] Comments by the Department (Oct. 12, 2015) (eDocket No. 201510-114759-01).
[26] Letter from MERC to PUC (Oct. 21, 2015) (eDocket No. 201510-114989-02); Letter from MERC to PUC (Oct. 26, 2015) (eDocket No. 201510-115098-01).

Hearings, with Administrative Law Judge Jeanne M. Cochran assigned, for a contested case proceeding. The Commission identified the parties as MERC and the Department.

21. On December 1, 2015, the OAG filed a petition to intervene.[27]

22. On December 7, 2015, the Administrative Law Judge held a prehearing conference.

23. On December 10, 2015, the Administrative Law Judge issued the First Prehearing Order that granted the intervention request of the OAG, set procedures for parties in the case, and established the following schedule:

Milestone	Due Date
Applicant Supplemental Direct Testimony Regarding Account 495 – Other Gas Revenues	Wednesday, December 30, 2015
Applicant Supplemental Direct Testimony on Issue No. 5 in Notice and Order for Hearing: "the extent to which the cost of system upgrades to serve the City of Rochester should be borne by all MERC ratepayers and if so, on what basis."	Monday, January 11, 2016
Deadline for Intervention	Friday, February 12, 2016
Applicant Supplemental Direct Testimony updating 2015 rate base and operating statement numbers to reflect actuals through December 2015	On or before Tuesday, February 9, 2016, the Company will provide the parties to this proceeding and the Administrative Law Judge with Trade Secret operating income and rate base schedules reflecting 2015 actual financial results through December 31, 2015 at the General Ledger account level. On or before Tuesday, March 1, 2016, the Company will then file and serve supplemental direct testimony supporting updated 2015 rate base and operating statement numbers through December 31, 2015, including bridge schedules to fiscal year 2014, fiscal year 2015, and test year 2016.

[27] OAG Petition to Intervene (Dec. 2, 2015) (eDocket No. 201512-116080-01).

Milestone	Due Date
Intervenor's Pre-Filed Direct Testimony	Friday, March 18, 2016
Public Hearings in Greater Minnesota (Albert Lea, Rochester, Rosemount and Cloquet)	March 28-31, 2016 (Tentative)
All Parties' Rebuttal Testimony	Tuesday, April 12, 2016
Applicant's Update on the Base Cost of Gas	Tuesday, April 12, 2016
All Parties' Surrebuttal Testimony	Monday, May 9, 2016
Minn. Stat. § 216B.16 Conference	Friday, May 20, 2016, at 10:00 a.m. at the MPUC offices in St. Paul
Evidentiary Hearings – Saint Paul	Monday, May 23-Friday, May 27, 2016 at the MPUC offices in St. Paul. The evidentiary hearing will begin at 9:30 a.m. on Monday, May 23, 2016
Applicant Files Issue Matrix	Wednesday, June 15, 2016
Non-Applicants' Response to Issue Matrix	Wednesday, June 29, 2016
All Parties' Initial Briefs	Wednesday, June 29, 2016
All Parties' Reply Briefs All Parties' Proposed Findings of Fact and Conclusions of Law	Tuesday, July 12, 2016
Report of the Administrative Law Judge	Friday, August 19, 2016

24. On December 11, 2015, SLGI filed a petition to intervene.[28]

25. On December 14, 2015, a Protective Order was issued to address the filing and use of trade secret information.

26. On December 15, 2015, the Administrative Law Judge issued the Amended First Prehearing Order to provide updated web addresses.

[28] SLGI Petition to Intervene (Dec. 11, 2015) (eDocket No. 201512-116397-02).

27. On December 22, 2015, the Administrative Law Judge issued an order granting intervention to SLGI.[29]

28. On December 30, 2015, and January 11, 2016, MERC filed Supplemental Direct Testimony regarding Account 495 and the Rochester Project Cost Allocation, respectively.[30]

29. On February 8, 2016, the Commission issued a Notice and Order for Hearing in Docket No. G-011/M-15-895 concerning MERC's Rochester Project in which the Commission removed all Rochester Project Phase II costs and issues from this rate case, and referred that matter to the Office of Administrative Hearings as a stand-alone contested case.[31]

30. Also on February 8, 2016, Constellation filed a petition to intervene.[32] On February 16, 2016, the Administrative Law Judge issued an order granting intervention to Constellation.[33]

31. On March 1, 2016, MERC filed supplemental direct testimony which updated 2015 rate base and operating statement numbers to reflect actuals through December 2015, including bridge schedules to fiscal year 2014, fiscal year 2015, and test year 2016.[34]

32. On March 18, 2016, Constellation, the OAG, and the Department each filed direct testimony from their witnesses.[35] SLGI did not file any testimony.

[29] ORDER GRANTING INTERVENTION TO THE SUPER LARGE GAS INTERVENORS (Dec. 22, 2015) (eDocket No. 201512-116731-01). While SLGI's petition to intervene was granted, SLGI did not actively participate in the proceeding.
[30] *See* Ex. 43 (DeMerritt Supplemental Direct); Ex. 38 (Lee Supplemental Direct). Mr. DeMerritt explained that all but a few thousand dollars of revenues in Account 495 do not flow through to MERC's revenue requirement, and therefore have no impact on the 2016 test year. Ex. 43 at 1-8 (DeMerritt Supplemental Direct).
[31] *In the Matter of a Petition by Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project*, MPUC Docket No. G-011/M-15-895, NOTICE AND ORDER FOR HEARING (Feb. 8, 2016).
[32] Constellation Petition to Intervene (Feb. 8, 2016) (eDocket No. 20162-118069-01).
[33] ORDER GRANTING INTERVENTION TO CONSTELLATION NEW ENERGY – GAS DIVISION, LLC (Feb. 16, 2016) (eDocket No. 20162-118356-01).
[34] *See* Ex. 44 (DeMerritt Second Supplemental Direct).
[35] *See* Ex. 200 (Sorenson Direct); Ex. 300 (Lebens Direct); Ex. 304 (Nelson Direct); Ex. 400 (Shah Direct); Ex. 402 (Davis Direct); Ex. 404 (Peirce Direct); Ex. 407 (LaPlante Direct); Ex. 409, 409a (Zajicek Direct and Attachments); Ex. 412 (Kundert Direct); Ex. 414 (Byrne Direct); Ex. 416 (St. Pierre Direct).

33. Public hearings were held according to the following schedule:

- Cloquet Chamber of Commerce, Cloquet, Minnesota, March 28, 2016.
- Rochester City Hall, Rochester, Minnesota, March 29, 2016.
- Albert Lea City Offices, Albert Lea, Minnesota, March 29, 2016.
- Dakota County Technical College, Rosemount, Minnesota, March 30, 2016.

34. On April 12, 2016, MERC, the OAG and the Department filed Rebuttal Testimony.[36]

35. On April 15, 2016, the public comment period for written public comments closed.

36. On May 9, 2016, all parties filed Surrebuttal Testimony with the exception of SLGI.

37. On May 13, 2016, the Department filed a Notice of Motion and Motion *In Limine,* to Exclude, In Part, Rebuttal Testimony of Christine M. Hans.[37]

38. On May 18, 2016, the Company agreed to withdraw that portion of Ms. Hans's Rebuttal Testimony that was the subject of the motion.[38]

39. On May 20, 2016, the Department filed the Sur-Surrebuttal Testimony of Michael N. Zajicek, for the purpose of revising Mr. Zajicek's recommendation so as to support the results of MERC's zero-intercept model for its Class Cost of Service Study.[39] The OAG requested the opportunity to respond at the evidentiary hearing to Mr. Zajicek's changed position, which the Administrative Law Judge allowed without opposition of any party.[40]

40. On May 20, 2016, the Administrative Law Judge convened a Minn. Stat. § 216B.16 conference.[41]

[36] *See* Ex. 14 (Kult Rebuttal); Ex. 16 (Gast Rebuttal); Ex. 18 (Nawrot Rebuttal); Ex. 23 (Kage Rebuttal); Ex. 26 (Kupsh Rebuttal); Ex. 28 (Clabots Rebuttal); Ex. 30 (Olsen Rebuttal); Ex. 32 (Kissinger Rebuttal); Ex. 35 (Hoffman Malueg Rebuttal); Ex. 39 (Lee Rebuttal); Ex. 45 (DeMerritt Rebuttal); Ex. 48 (Hevert Rebuttal); Ex. 301 (Lebens Rebuttal); Ex. 306 (Nelson Rebuttal); Ex. 410 (Zajicek Rebuttal).
[37] Notice of Motion and Motion *In Limine* to Exclude, in Part, Rebuttal Testimony of Christine M. Hans (May 13, 2016) (eDocket No. 20165-121313-01).
[38] Ex. 19 (Hans Amended Rebuttal).
[39] Ex. 411 (Zajicek Sur-Surrebuttal).
[40] Evidentiary Hearing Transcript Volume (Tr. Vol.) 1 at 14.
[41] May 20, 2016 Prehearing Tr. at 1-27.

41. On May 23-24, 2016, the evidentiary hearing was held in the Commission's small hearing room in St. Paul, Minnesota.[42]

42. On June 15, 2016, Applicant filed its Issues Matrix.[43]

43. On June 29, 2016, Non-Applicants filed their Responses to Applicant's Issues Matrix.[44]

44. Also on June 29, 2016, all parties except SLGI filed initial briefs.[45]

45. On July 12, 2016, all parties except SLGI filed reply briefs.[46]

V. Comments from the Public

46. As noted above, the public had the opportunity to comment on MERC's proposed rate increases both orally and in writing. Over 20 people attended the four public hearings in March 2016, with 12 offering comments at the hearings. In addition over 40 written public comments were received by the April 15, 2016 deadline via the *SpeakUp!* system on the Commission's website and by U.S. Mail.[47] The vast majority of the public comments were from residential customers, although some individuals representing business interests also provided comments.

47. MERC's customers raised a number of concerns, including but not limited to: the size of the proposed rate increases; the frequency of rate increases sought by MERC; the burden on low-income customers and customers with fixed incomes, particularly retirees; concerns by customers in the former Interstate Power and Light (IPL) service territory, who recently became MERC customers as a result of an acquisition, about the size of the rate increases they would face;[48] and concerns by business customers about their ability to compete. In addition, some customers questioned the need for a rate increase in light of lower natural gas prices. Other customers suggested that MERC should do a better job of controlling its costs instead of raising rates. In addition, customers raised particular billing and customer service concerns. Finally, a

[42] Tr. Vols. 1-2.
[43] Issues Matrix (June 15, 2016) (eDocket No. 20166-122271-01).
[44] OAG Response to Issues Matrix (June 29, 2016) (eDocket No. 20166-122793-01); Department Response to Issues Matrix (June 29, 2016) (eDocket No. 20166-122791-03); Constellation Response to Issues Matrix (June 29, 2016) (eDocket No. 20166-122771-02).
[45] Department Initial Br. (June 29, 2016) (eDocket No. 20166-122791-01); MERC Initial Br. (June 29, 2016) (eDocket No. 20166-122788-01); Constellation Initial Br. (June 29, 2016) (eDocket No. 20166-122771-01); OAG Initial Br. (June 29, 2016) (eDocket No. 20166-122790-01).
[46] Constellation Reply Br. (July 12, 2016) (eDocket No. 20167-123199-01); OAG Reply Br. (July 12, 2016 (eDocket No. 20167-123200-01); MERC Reply Br. (July 12, 2016) (eDocket No. 20167-123198-01); Department Reply Br. (eDocket No. 20167-123191-01).
[47] *See* Ex. A (Summary of Public Comments).
[48] In December 2014, the Commission approved MERC"s acquisition of the IPL's assets in Minnesota. IPL's customers had not seen a rate increase since 1996. *See In the Matter of a Request for the Approval of the Asset Purchase and Sale Agreement Between Interstate Power and Light Company and Minnesota Energy Resources Corporation*, MPUC Docket No. G001, 011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 2 (Dec. 8, 2014).

number of customers felt that MERC had not sufficiently explained the reasons for its proposed rate increase in its brochure entitled "Important Information About Your Rates."[49]

48. A full summary of the public comments is included as Attachment A to this report.

VI. Legal Standard

49. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[50] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market. Minnesota law recognizes this principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[51]

50. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change is just and reasonable.[52]

51. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, even if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[53] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[54]

52. In addition, the Commission is to set rates to encourage conservation and renewable energy use to the maximum reasonable extent.[55]

53. The Commission acts in both a quasi-judicial and a quasi-legislative capacity in setting rates. On purely factual issues, the Commission acts in a quasi-judicial capacity. On issues involving policy judgment, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the public interest.[56]

[49] *See* Ex. A (Summary of Public Comments).
[50] Minn. Stat. § 216B.03 (2016).
[51] Minn. Stat. § 216B.16.
[52] Minn. Stat. § 216B.16, subd. 4.
[53] *In re Northern States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987).
[54] Minn. Stat. § 216B.03.
[55] Minn. Stat. § 216B.03.
[56] *St. Paul Chamber of Commerce v. Minn. Public Utilities Comm'n*, 251 N.W.2d 350, 356-57 (Minn. 1977).

VII. Disputed Revenue Requirement Issues

54. The revenue requirement portion of a rate case seeks to determine what additional revenue is needed to meet the utility's required operating income, based upon a "test year" of operations. The required operating income is derived from determining the amount of investments in rate base that have been made by a utility's shareholders, and multiplying the approved rate base times the rate of return that is determined to be appropriate for the Company.[57]

55. After determining the required operating income, the Company's test year expenses and revenues are evaluated to determine the current operating income for the test year (in this case 2016). The difference between the required operating income and the test year operating income is the income deficiency. The income deficiency is converted into a gross revenue deficiency amount.[58]

56. This section of the Report discusses revenue requirement issues that are disputed between the parties.

A. Rate of Return

57. Minnesota law recognizes the need for a public utility to earn a fair and reasonable rate of return (ROR). In setting just and reasonable rates, Minn. Stat. § 216B.16, subd. 6, requires the Commission to:

> give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a **fair and reasonable return** upon the investment in such property.[59]

58. A fair and reasonable ROR is one that enables the utility to attract sufficient capital, at reasonable terms. Regulators seek to set the ROR at a level that, when multiplied by the rate base, will give the utility enough, but no more than, a reasonable return on its total investment.[60]

59. The ROR is the overall cost of capital. The ROR is calculated as the sum of each component of the capital structure times its corresponding cost. The capital structure is made up of components which may include common equity, preferred stock, short-term

[57] *See* Ex. 41, Schedule SSD-23 (DeMerritt Direct); Ex. 4, Vol. 3, Doc. 1 (Initial Filing); Ex. 416, MAS-2 (St. Pierre Direct).
[58] *See* Ex. 41, Schedule SSD-23 (DeMerritt Direct); Ex. 4, Vol. 3, Doc. 1 (Initial Filing); Ex. 416, MAS-2 (St. Pierre Direct).
[59] Minn. Stat. § 216B.16, subd. 6 (emphasis added).
[60] Ex. 412 at 3 (Kundert Direct); Minn. Stat. § 216B.16, subd. 6; *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923); *Federal Power Comm'n, et al. vs. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

debt and long-term debt. These amounts are represented as dollar amounts and as percentages of the total capital.[61]

60. In this case, there is no dispute as to the Company's proposed capital structure, the cost of short-term debt, or the cost of long-term debt.[62] The parties disagree, however, about the cost of equity or return on equity (ROE). Each component of the MERC's overall ROR (capital structure, cost of debt, and ROE) is discussed below.

1. Capital Structure

61. To arrive at the cost of capital (overall rate of return), it is necessary to determine the amount of long-term debt, short-term debt, preferred stock, and common equity held by MERC. This represents the Company's capital structure. While MERC has its own capital structure, it is a hypothetical capital structure because MERC is not a publicly traded company. Because MERC is a subsidiary of WEC,[63] its equity consists of MERC's retained earnings plus any equity infusion from its parent company minus any dividends paid by MERC to WEC.[64]

62. MERC sets an equity ratio target of between 50 to 55 percent, and a short term debt cap of 5 percent.[65] MERC has historically borrowed long-term debt internally from its parent as needed to finance its capital expenditures but, in this proceeding, has proposed to sell debt externally.[66]

63. MERC proposed a projected capital structure consisting of 45.59 percent long-term debt, 4.08 percent short-term debt, and 50.32 percent common stock equity.[67] This proposed capital structure reflected the Company's proposed 2016 average balances for long-term debt (13-month average), short-term debt (13-month average), and common equity (13-month average).[68]

64. The Department reviewed MERC's proposed capital structure and concluded that the proposed capital structure was reasonable. The Department based its conclusion on a comparison of MERC's proposed capital structure with its Commission-approved capital structure from its last three rate cases and with a comparison of the proposed capital structure to the capital structures of comparable companies.[69]

[61] Ex. 412 at 29 (Kundert Direct).
[62] The Department and MERC were the only parties that provided testimony on the issues of capital structure, the cost of long term debt, and the cost of short term debt.
[63] Ex. 412 at 29 (Kundert Direct).
[64] Ex. 412 at 29 (Kundert Direct).
[65] Ex. 412 at 29-30 (Kundert Direct).
[66] Ex. 412 at 30 (Kundert Rebuttal).
[67] Ex. 15, Schedule LGJ-01 (Gast Direct).
[68] Ex. 15 at 4-5 (Gast Direct).
[69] Ex. 412 at 30-34 (Kundert Direct).

65. The Administrative Law Judge concurs with the Department's conclusion that MERC's proposed capital structure is reasonable and recommends that it be adopted in this case.

2. Cost of Short-Term and Long-Term Debt

66. MERC proposed a test year cost of long-term debt of 5.1114 percent and short-term cost of debt of 3.0545 percent, based on the 13-month average over the period December 1, 2014 through December 31, 2015.[70]

67. The Department agreed that MERC's proposed method for calculating its cost of short- and long-term debt is reasonable but recommended updating the figures in later testimony given that it is a market-based estimate.[71] In Surrebuttal Testimony, the Department's witness, Mr. Kundert, recommended a cost of long-term debt of 4.8627 percent and a cost of short-term debt of 2.037 percent.[72] MERC agreed with this recommended update.[73]

68. The Administrative Law Judge finds that the Department's proposed cost of long-term debt of 4.8627 percent and cost of short-term debt of 2.037 percent are reasonable and should be approved in this rate case.

3. Cost of Equity or ROE

69. As the Commission recently noted, "[o]ne of the critical components of a fair and reasonable return upon investment is the return on common equity, which – together with debt – finances utility infrastructure."[74] Once the ROE is determined, the resulting ROR can be calculated using the capital structure, the cost of debt, and the ROE.

70. As noted above, Minn. Stat. § 216B.16B, subd. 6, requires the Commission to give due consideration to the public utility's need "to earn a fair and reasonable return" upon the investment in property that is used and useful in rendering utility service.

71. Similarly, Minnesota courts have recognized that:

> Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the

[70] Ex. 15 at 4-5, Schedule LJG-01 (Gast Direct).
[71] Ex. 412 at 34-35 (Kundert Direct).
[72] Ex. 413 at 2 (Kundert Surrebuttal).
[73] Ex. 53 (DeMerritt Summary Statement).
[74] *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-15-424, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 38 (June 3, 2016) (2015 CPE RATE CASE ORDER).

> public utility company of its property in violation of the Fourteenth Amendment.[75]

72. The United States Supreme Court has defined the proper regulatory balance between the investments made by investors and the interests of ratepayers in two seminal cases: *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia (Bluefield)*, 262 U.S. 679 (1923) (*Bluefield*), and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) (*Hope*). In *Bluefield*, the Court held that a utility's return must be reasonably sufficient to assure financial soundness and provide the utility adequate means to raise capital. The Court recognized that a utility did not have a right to extremely large profits similar to those realized in speculative ventures, but rather that the utility's return:

> should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[76]

73. In *Hope*, the Court reaffirmed and redefined the *Bluefield* principles, making an important addition: the Court noted that a just and reasonable return should be similar to returns on investments in other businesses having a corresponding risk.[77]

74. The decisions in these cases yield three key guidelines as to a reasonable rate of return on common equity. The ROE should be:

a. sufficient to enable the utility to attract capital;

b. sufficient to enable the utility to maintain its credit rating and financial integrity; and

c. commensurate with returns being earned on other investments having similar risks.[78]

75. A fair and reasonable ROE is critical because it allows the utility to attract the capital necessary to provide safe, reliable service while maintaining its financial integrity.[79]

76. Only MERC and the Department presented testimony on the appropriate ROE for MERC. The parties disagree on: (1) how best to estimate the ROE for MERC; (2) what constitutes a reasonable ROE for the Company.

[75] *Hibbing Taconite Co. v. Minn. Pub. Serv. Comm'n*, 302 N.W.2d 5, 10 (Minn. 1980) (citing *Bluefield*, 262 U.S. at 690).
[76] *Bluefield*, 262 U.S. at 693.
[77] *Hope*, 320 U.S. at 603.
[78] Ex. 412 at 3-4 (Kundert Direct).
[79] Ex. 47 at 13 (Hevert Direct).

a. Summary of Recommendations of the Parties

77. MERC determined that its cost of equity is currently in the range of 10.0 to 10.6 percent, and recommended an ROE of 10.3 percent, the midpoint. MERC's recommendation includes an adjustment for flotation costs.[80] MERC recommended an ROE of 10.3 percent in both its Direct Testimony and in its Rebuttal Testimony.[81]

78. MERC based its recommendation on three different analytical tools: the Discounted Cash Flow model (DCF); the Capital Asset Pricing Model (CAPM); and the Bond Yield Plus Risk Premium model. MERC also took into consideration qualitative factors in arriving at its recommendation, including capital market conditions, the Company's size, its volume of transportation customers, and its level of capital expenditures in the next three years.[82]

79. The Department initially recommended an ROE of 9.67 percent.[83] In Surrebuttal Testimony, the Department revised its recommendation downward to 9.11 percent based on updated data.[84] The Department's initial and revised recommendations both include an adjustment for flotation costs.[85]

80. The Department used the DCF model to develop its ROE recommendations. The Department also performed a CAPM analysis as a check on its results.[86]

b. Analytical Tools Used by MERC and the Department

81. Because the cost of equity is market-driven, it must be based on observable market information. In this case, MERC and the Department used several analytical techniques (DCF model, CAPM, and Bond Yield Plus Risk Premium model) that rely on market-based data to quantify investor expectations regarding equity returns, adjusted for certain incremental costs and risks. By their nature, these models produce a range of results from which the required ROE must be determined.[87]

82. The DCF model is a market-oriented method based on the theory that the current price of a stock represents "the present value of all expected future dividends, discounted by the appropriate rate of return."[88] The DCF model uses the current dividend yield and the expected growth rate of dividends to determine what rate of return is

[80] Ex. 47 at 3 (Hevert Direct).
[81] Ex. 47 at 3 (Hevert Direct); Ex. 48 at 2 (Kundert Rebuttal Testimony).
[82] Ex. 47 at 3-4 (Hevert Direct).
[83] Ex. 412 at 1 (Kundert Direct).
[84] Ex. 413 at 2 (Kundert Surrebuttal).
[85] Ex. 412 at 21-23 (Kundert Direct); Ex. 413 at 10 (Kundert Surrebuttal).
[86] Ex. 412 at 13-28 (Kundert Direct); Ex. 413 at 1-13 (Kundert Surrebuttal).
[87] Ex. 47 at 20 (Hevert Direct); Ex. 412 at 13-28 (Kundert Direct).
[88] Ex. 412 at 5 (Kundert Direct); *see also* Ex. 47 at 21 (Hevert Direct).

required to compensate investors for the risk of owning the stock, known as the cost of equity.[89]

83. The simplest form of the DCF is known as the Constant Growth Rate DCF model. This model expresses the required ROE as the sum of the expected dividend yield and the long term growth rate. This model assumes: (1) a constant average growth rate for earnings and dividends; (2) a stable dividend payout for dividends; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.[90]

84. The Two-Growth DCF and Multi-Stage DCF models are variations of the Constant Growth Rate DCF model that accommodate different growth rates. The Two-Growth DCF model is used when the short-term projected dividend growth rate for a company may not be sustained in the long-run. The Two-Growth DCF model accommodates two different growth rates. The Two-Growth DCF model assumes that dividends grow at one rate for a short time (e.g. five years), and then grow at a second sustainable rate in perpetuity.[91] The Multi-Stage DCF model is also an extension of the Constant Growth Rate DCF model. The Multi-Stage DCF model allows the analyst to specify growth rates over three distinct stages.[92]

85. The CAPM is a risk premium model that estimates the cost of equity as a function of a risk-free return plus a risk premium.[93] The risk premium represents the compensation paid to investors for the non-diversifiable risk or "systematic" risk of that security.[94] To perform a CAPM analysis, it is necessary to determine the rate of return on a riskless asset, along with the appropriate beta and the appropriate required rate of return on the market portfolio. The beta measures the portion of the variability in a stock's return that maintains a systematic relationship with a broad market index, and indicates the direction and degree of change in a stock's return relative to the changes in the market as a whole.[95]

86. The empirical CAPM (ECAPM) is a variation on the traditional CAPM. The ECAPM was developed because empirical studies have shown that, for companies with a beta smaller than one (1), the traditional CAPM results in a downward bias of the required ROE compared to the theoretical CAPM. To address this potential downward bias, the ECAPM is used and compared to the traditional CAPM.[96]

87. The Bond Yield Plus Risk Premium model determines the cost of equity by adding a premium to the current corporate bond yield. The model is based on the financial tenet that because equity investors bear the residual risk of ownership, their returns are subject to more risk than the returns to bond holders. The risk premium is estimated using

[89] Ex. 412 at 5-6 (Kundert Direct); Ex. 47 at 22 (Hevert Direct).
[90] Ex. 47 at 22 (Hevert Direct); Ex. 412 at 6 (Kundert Direct).
[91] Ex. 412 at 6, 18-19 (Kundert Direct).
[92] Ex. 47 at 29 (Hevert Direct).
[93] Ex. 47 at 34 (Hevert Direct).
[94] Ex. 47 at 34 (Hevert Direct); Ex. 412 at 23-24 (Kundert Direct).
[95] Ex. 47 at 34 (Hevert Direct); Ex. 412 at 24 (Kundert Direct).
[96] Ex. 412 at 27-28 (Kundert Direct).

a regression analysis of historical ROEs for natural gas companies and Treasury yield data. The risk premium is expressed as a function of the natural log of the 30-year Treasury yield.[97]

88. The Commission has historically placed the greatest reliance on the DCF model when determining the ROE in a rate case, and used the CAPM as a "secondary, corroborating resource."[98] The Commission has historically relied the least on the Bond Yield Plus Risk Premium model, considering it prone to producing volatile and unreliable outcomes.[99]

c. Proxy Groups Used by MERC and the Department

89. To determine the cost of equity or ROE for MERC, the first step is to select a group of proxy companies that are both publicly traded and comparable to MERC.

90. Because MERC is not a publicly traded company, a proxy group is necessary for the ROE estimation process.[100]

91. While a parent company could be used as a proxy under certain circumstances, WEC is not a good proxy for MERC because WEC receives a fairly small portion of its net income from natural gas distribution operations. Consequently, WEC's investors would face different risks than would an equity investor in MERC.[101] In addition, even if MERC's jurisdictional assets did constitute the entirety of its parent company operations, it is possible that transitory events, such as unfounded rumors, could bias its market value in one way or another over a given period of time.[102]

92. To develop a proxy group, MERC started with the universe of companies that Value Line, an investor service, classifies as Electric or Natural Gas Utilities. MERC then applied the following screens and excluded companies that:

- do not consistently pay quarterly cash dividends;
- are not covered by at least two utility industry equity analysts;
- do not have investment grade senior bond and/or corporate credit ratings from Standard and Poor's (S&P);
- have less than 60.00 percent of net operating income from regulated gas utility operations; and

[97] Ex. 47 at 37-39 (Hevert Direct).
[98] 2015 CPE RATE CASE ORDER at 38.
[99] *Id.*
[100] Ex. 47 at 15-16 (Hevert Direct).
[101] Ex. 412 at 7 (Kundert Direct).
[102] Ex. 47 at 16 (Hevert Direct).

- that are known to be party to a merger or other significant transaction during the study period.[103]

93. These screens are intended to identify proxy companies that are fundamentally comparable to MERC's business and risk profile, and to exclude companies whose market prices may have been affected by unusual events during the study period.[104] MERC's witness, Mr. Hevert, noted that the criteria he used properly balance the objective of developing a proxy group that is fundamentally comparable to MERC, with the need to have a sufficiently large number of companies.[105]

94. After applying these screens, MERC's witness, Mr. Hevert, identified the following companies: AGL Resources; Atmos Energy; Laclede Group, Inc.; New Jersey Resources; Northwest Natural Gas; Piedmont Natural Gas; South Jersey Industries, Inc.; Southwest Gas; and WGL Holdings.[106] Mr. Hevert used this group of nine companies as the proxy group in his Direct Testimony.

95. The Department's witness, Mr. Kundert, applied a similar set of criteria to identify his proxy group.[107] The Department identified companies that: (1) are classified as natural gas utilities by SIC Code or Value Line; (2) are traded on one of the stock exchanges; (3) have a S&P bond rating in the range of BBB to A+; and (4) received 60 percent of their total net operating income from natural gas in their most recent reporting period.[108]

96. Mr. Kundert removed two companies (Piedmont Natural Gas and AGL Resources) that had announced merger plans, and one company (ONE Gas) because it did not have sufficient earnings information to perform the DCF analysis.[109]

97. Following these steps, the Department's final proxy group consisted of six companies: Atmos Energy; Laclede Group, Inc.; Northwest Natural Gas; South Jersey Industries, Inc.; Southwest Gas; and WGL Holdings.[110] All six of these companies were also included in MERC's initial proxy group.

98. In Rebuttal Testimony, Mr. Hevert agreed that AGL Resources and Piedmont Natural Gas should be excluded from his proxy group due to merger activity.[111]

99. As a result, after Rebuttal Testimony, the only difference between MERC's proxy group and the Department's proxy group was the inclusion of New Jersey Resources in MERC's group. The Department's expert Mr. Kundert elected to not include New Jersey Resources in the Department's proxy group because the company did not

[103] Ex. 47 at 17 (Hevert Direct).
[104] Ex. 47 at 17 (Hevert Direct).
[105] Ex. 47 at 19 (Hevert Direct).
[106] Ex. 47 at 18 (Hevert Direct).
[107] Ex. 412 at 8-13 (Kundert Direct).
[108] Ex. 412 at 9-12 (Kundert Direct).
[109] Ex. 412 at 12 (Kundert Direct).
[110] Ex. 412 at 13 (Kundert Direct).
[111] Ex. 48 at 5 (Hevert Rebuttal).

generate at least 60 percent of its operating income from natural gas distribution for its most recent reporting period (September 2015), but Mr. Kundert recognized the inclusion of New Jersey Resources in MERC's proxy group was reasonable.[112] Mr. Kundert noted that MERC's proxy group includes New Jersey Resources as a result of a minor difference in the 60 percent of net operating profit screen that MERC's witness, Mr. Hevert, used as compared to the screen that Mr. Kundert used.[113]

100. To minimize the scope of contested issues, Mr. Hevert considered the results of the ROE models provided in Rebuttal Testimony both with and without New Jersey Resources in his proxy group.[114]

101. The record shows both MERC and the Department used sound analytical criteria in developing their proxy groups, and the resulting groups are reasonable for use in estimating MERC's ROE.

d. MERC's ROE Analysis

102. In developing a recommended ROE, MERC relied upon both quantitative analysis and qualitative factors. MERC used two different DCF models: the Constant Growth DCF and the Multi-Stage DCF. MERC also used the CAPM and Bond Yield Plus Risk Premium method of estimating ROE. MERC's witness, Mr. Hevert, used these four different methods to "mitigate the effects of assumptions and inputs associated with any single approach."[115] In addition, Mr. Hevert considered specific business risks faced by MERC and the capital market environment.[116] MERC's analysis is discussed in more detail below.

i. MERC's Constant Growth DCF Analysis

103. As noted above, the DCF model is based on the theory that a given stock's current price represents the present value of all expected future cash flows. The DCF analysis expresses the cost of equity as the sum of the expected dividend yield and the long-term growth rate.[117] The formula for the Constant Growth DCF model, in its simplified form, is as follows:

Cost of Equity= {[Current Dividend *(1+ 0.5*g)]/Current Stock Price} + Growth Rate[118]

[112] Ex. 412 at 12, 42-43 (Kundert Direct).
[113] Ex. 412 at 42 (Kundert Direct).
[114] Ex. 48 at 6 (Hevert Rebuttal).
[115] Ex. 48 at 28 (Hevert Direct).
[116] Ex. 48 at 20-56 (Hevert Direct); Ex. 48 at 2 (Hevert Rebuttal).
[117] Ex. 48 at 22 (Hevert Direct).
[118] *See* Ex. 412 at 13, 16 (Kundert Direct); Ex. 47 at 22-23 (Hevert Direct).

104. In this equation, the first term is the expected dividend yield and the second term is the expected long-term growth rate.[119]

105. In his Constant Growth DCF analysis, Mr. Hevert based the expected dividend yield on the current annualized dividend and the average closing stock prices of the proxy companies for the 30-, 90-, and 180-trading days.[120] In Direct Testimony, Mr. Hevert based his analysis on the 30-, 90-, and 180- trading days as of August 14, 2015.[121]

106. Mr. Hevert used the 30-, 90-, and 180-day averaging periods to calculate the "Current Stock Price" for use in the DCF equation to ensure that the DCF model's results "are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term." In Mr. Hevert's view, the use of the 30-, 90-, and 180-day averaging periods reasonably balances those concerns.[122]

107. In terms of estimating the long term growth rate for use in the formula, Mr. Hevert noted that the Constant Growth DCF model assumption of a single growth estimate in perpetuity means that one must assume a constant payout ratio, and that earnings per share, dividends per share, and book value per share all grow at the same constant rate. Over the long term, however, dividend growth can only be sustained by earnings growth. Accordingly, it is important to incorporate a variety of measures of long-term earnings growth into the Constant Growth DCF model.[123]

108. For growth estimates in his Constant Growth DCF analysis, Mr. Hevert utilized: (1) the Zacks consensus long-term earnings growth estimates; (2) the First Call (a/k/a Thomson) consensus long-term earnings growth estimates; (3) the Value Line long-term earnings growth estimates; and 4) an estimate of Retention Growth.[124]

109. Retention Growth is an alternative approach to the use of analysts' earnings growth estimates, which assumes that a firm's growth is a function of its expected earnings, and the extent to which it retains earnings to invest in the enterprise. In its simplest form, the model represents the long-term growth as the product of the retention ratio and the expected return on book equity.[125]

110. After completing his Constant Growth DCF analysis, Mr. Hevert adjusted his results to account for flotation costs. Flotation costs are the costs associated with the

[119] Ex. 47 at 22 (Hevert Direct).
[120] Ex. 47 at 22 (Hevert Direct).
[121] Ex. 47 at 25 (Hevert Direct).
[122] Ex. 47 at 23 (Hevert Direct).
[123] Ex. 47 at 23-24 (Hevert Direct).
[124] Ex. 47 at 25-26 (Hevert Direct). First Call is also referred to as Thomson First Call Consensus or Thomson. *See* Ex. 412 at 43 (Kundert Direct).
[125] Ex. 47 at 26 (Hevert Direct).

sale of new issues of common stock. Such costs include out-of-pocket expenditures for preparation, filing, underwriting, and other issuance costs of common stock.[126]

111. Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." Flotation costs are incurred over time. As a result, the great majority of a utility's flotation cost is incurred prior to the test year, but remains part of the cost structure that exists during the test year and beyond. Therefore, recovery of flotation costs is appropriate even if no new issuances are planned in the near future because failure to allow such costs may deny MERC the opportunity to earn its required rate of return.[127]

112. Mr. Hevert recommended a flotation cost adjustment of approximately 0.14 percent (14 basis points) in Direct Testimony. Mr. Hevert estimated the flotation cost adjustment based on a weighted average of issuance costs from his proxy group.[128]

113. MERC conducted the Constant Growth DCF analysis for each company in its proxy group and averaged the results for the proxy group.[129] The results of MERC's Constant Growth DCF analysis for its proxy group, including flotation costs, as set forth in Mr. Hevert's Direct Testimony are as follows:[130]

MERC's Initial Constant Growth DCF Results

	MEAN LOW	MEAN	MEAN HIGH
30-Day Average	7.69%	9.29%	10.87%
90-Day Average	7.67%	9.26%	10.84%
180-Day Average	7.58%	9.18%	10.76%

114. As this table shows, Mr. Hevert's Constant Growth DCF analysis developed a range of results from 7.58 percent to 10.87 percent in Direct Testimony.[131]

115. Mr. Hevert calculated the proxy group's Mean High DCF result using the maximum earnings per share growth rate as reported for Value Line, Zacks, and Thomson and the retention growth estimate for each proxy group company in combination with dividend yield for each of the proxy group companies. The Mean High results reflect the average maximum DCF results for the proxy group as a whole within the averaging period.[132]

[126] Ex. 47 at 47 (Hevert Direct).
[127] Ex. 47 at 48 (Hevert Direct); Ex. 412 at 21-22 (Kundert Direct).
[128] Ex. 47 at 50, RBH-D, Schedule 11 (Hevert Direct).
[129] Ex. 47 at 22, RBH-2 (Hevert Direct).
[130] Ex. 47 at 27 (Hevert Direct)
[131] Ex. 47 at 27 (Hevert Direct).
[132] Ex. 47 at 27 (Hevert Direct).

116. Mr. Hevert used a similar approach to calculate the proxy group Mean Low results, using instead the minimum growth rate as reported by Value Line, Zacks, and Thomson and the retention growth estimate for each company. The Mean Low results reflect the average minimum DCF results for the proxy group as a whole within the averaging period.[133]

117. The Mean represents the average mean results for the proxy group within the applicable period.[134]

118. The average of Mr. Hevert's 30-, 90-, and 180-day Mean results in his Direct Testimony was 9.24 percent.[135]

119. In Mr. Hevert's view, the Mean Low results, which ranged from 7.58 to 7.69 percent, were well below any reasonable ROE for MERC. For that reason he gave little weight to the low end of his Constant Growth DCF analysis in developing his final ROE recommendation.[136]

120. In his Rebuttal Testimony, Mr. Hevert updated his proxy group and his Constant Growth DCF analysis. Because of announced mergers, Mr. Hevert removed AGL Resources and Piedmont Natural Gas from his proxy group as noted above.[137] Also, the 30-, 90-, and 180- trading days' closing prices were updated to the period ending February 29, 2016.[138] Mr. Hevert also updated his analysis with the most recent growth rate estimates from Zacks, Value Line, and Thompson as of February 29, 2016.[139] Finally, Mr. Hevert revised his flotation cost adjustment from 14 basis points down to 13 basis points in Rebuttal Testimony.[140] MERC's updated analysis produced the following results, including updated flotation costs:

MERC's Updated Constant Growth DCF Results

	MEAN LOW	MEAN	MEAN HIGH
30-Day Average	8.22%	9.41%	11.09%
90-Day Average	8.37%	9.57%	11.25%
180-Day Average	8.51%	9.71%	11.39%

121. As this table shows, Mr. Hevert's updated Constant Growth DCF analysis developed a range of results from 8.22 percent to 11.39 percent in Rebuttal Testimony. The Mean ranged from 9.41 percent (30-day average) to 9.71 percent (180-day average).

133 Ex. 47 at 27 (Hevert Direct).
134 *See* Ex. 47 at 27 (Hevert Direct).
135 *See* Ex. 47 at 27 (Hevert Direct).
136 Ex. 47 at 28, 56-57 (Hevert Direct).
137 Ex. 48 at 5 (Hevert Rebuttal).
138 Ex. 48 at 42, RBH-R1 (Hevert Rebuttal). The results using Mr. Kundert's proxy group were slightly higher. Ex. 48 at 42, RBH-R1.
139 Ex. 48, RBH-R2 (Hevert Rebuttal).
140 Ex. 48, RBH-R1 (Hevert Rebuttal).

The average of Mr. Hevert's updated 30-, 90-, and 180-day Mean results was 9.56 percent.[141]

ii. MERC's Multi-Stage DCF Analysis

122. In addition to the Constant Growth DCF analysis, Mr. Hevert performed a Multi-Stage DCF analysis. The Multi-Stage model enables the analyst to specify growth rates over three distinct stages (i.e. time periods), avoiding the limiting assumptions about growth, payout ratios, and the price-to-earnings ratio underlying the Constant Growth form of the DCF model.[142]

123. The Multi-Stage DCF model sets the company's stock price equal to the present value of future cash flows received over the three stages. In the first two stages, cash flows are defined as projected dividends. In the third stage, cash flows equal both dividends and the expected price at which the stock will be sold at the end of the period (i.e. the "terminal price"). MERC's witness, Mr. Hevert, calculated the terminal price based on the Gordon model, which defines the terminal price as the expected dividend divided by the difference between the Cost of Equity (i.e. the discount rate) and the long-term expected growth rate. In essence, the terminal price is defined by the present value of the remaining "cash flows" in perpetuity. In each of the three stages, the dividend is the product of the projected earnings per share and the expected dividend payout ratio.[143]

[141] Ex. 48 at 27 (Hevert Direct).
[142] Ex. 47 at 29 (Hevert Direct).
[143] Ex. 47 at 30 (Hevert Direct).

124. The Multi-Stage DCD model's structure is set forth in the chart below:[144]

Multi-Stage DCF Model Structure

Stage	**0**	**1**	**2**	**3**
Cash Flow Component	Initial Stock Price	Expected Dividend	Expected Dividend	Expected Dividend + Terminal Value
Inputs	Stock Price Earnings Per Share ("EPS") Dividends Per Share ("DPS")	Expected EPS Expected DPS	Expected EPS Expected DPS	Expected EPS Expected DPS Terminal Value
Assumptions	30-,90-, and 180-day average stock price	EPS Growth Rate Payout Ratio	Growth Rate Change Payout Ratio Change	Long-term Growth Rate Long-term Payout Ratio

125. Mr. Hevert's Multi-Stage DCF model produced a range of ROE results: 9.28 percent to 10.32 percent in Direct Testimony; and 8.99 percent to 10.13 percent in Rebuttal Testimony. These results were narrower than those that resulted from his Constant Growth DCF model.[145]

iii. MERC's CAPM Analysis

126. In addition to the DCF analyses discussed above, MERC's witness, Mr. Hevert, conducted a CAPM analysis.

127. As noted above, the CAPM is a risk premium model that estimates the cost of equity as a function of a risk-free return plus a risk premium, to compensate investors for the non-diversifiable or "systematic" risk of that security.[146]

128. In its simplest form, CAPM can be expressed as follows:

k = r + beta * (Km – r)

where "k" is the required rate of return on the stock in question, "r" is the rate of return on a riskless asset, and "Km" is the required rate of return on the market portfolio.[147]

[144] Ex. 47 at 30 (Hevert Direct).
[145] Ex. 47 at 33 (Hevert Direct); Ex. 48 at 42 (Hevert Rebuttal).
[146] Ex. 47 at 34 (Hevert Direct).
[147] Ex. 412 at 23-24 (Kundert Direct); Ex. 47 at 34 (Hevert Direct) (setting forth same formula but using a different symbol for the market portfolio rate of return).

129. MERC used two different estimates of the risk-free rate of return: (1) the current 30-day average yield on 30-year Treasury bonds, and (2) the near-term projected 30-year Treasury yield.[148] Mr. Hevert used a 30-year Treasury bond to determine the risk-free rate of return because it most closely matches the duration of equity investments.[149]

130. For the risk premium, Mr. Hevert developed a forward-looking estimate of the Market Risk Premium. This approach is based on the market required return less the current 30-year Treasury bond yield. Mr. Hevert relied on Bloomberg and Value Line to develop his estimate.[150]

131. For the Beta coefficient, Mr. Hevert used the Beta coefficients reported by Bloomberg and Value Line and calculated the average Beta coefficient for his proxy group.[151]

132. Using the CAPM model, Mr. Hevert produced an initial range of results from 9.74 percent to 11.72 percent in Direct Testimony. In Rebuttal Testimony, Mr. Hevert's updated CAPM analysis produced a range of results from 8.81 percent to 11.55 percent.[152]

133. In addition, in Rebuttal Testimony, Mr. Hevert included an ECAPM analysis that yielded a range of results from 9.69 percent to 12.15 percent.[153]

iv. MERC's Bond Yield Plus Risk Premium Analysis

134. MERC also performed a Bond Yield Plus Risk Premium analysis to support its ROE recommendation.[154]

135. Risk premium approaches estimate the cost of equity as the sum of an equity risk premium and a bond yield. The equity risk premium is the difference between the cost of equity and long-term Treasury yields.[155]

136. Merc's witness, Mr. Hevert, defined the Risk Premium as the difference between the authorized ROE for natural gas utilities and the 30-year Treasury yield. Mr. Hevert calculated the average ROE for natural gas utilities based on data from 1,017 natural gas rate proceedings between January 1980 and August 14, 2015, as reported by Regulatory Research Associates.[156]

[148] Ex. 47 at 35 (Hevert Direct).
[149] Ex. 48 at 20-23 (Hevert Rebuttal).
[150] Ex. 47 at 35-36 (Hevert Direct).
[151] Ex. 47 at 36 (Hevert Direct).
[152] Ex. 47 at 36 (Hevert Direct); Ex. 48 at 43 (Hevert Rebuttal).
[153] Ex. 48 at 44 (Hevert Rebuttal).
[154] Ex. 47 at 37 (Hevert Direct).
[155] Ex. 47 at 37 (Hevert Direct).
[156] Ex. 47 at 37-38 (Hevert Direct).

137. In addition to calculating the average authorized ROE, Mr. Hevert also calculated the average period between the filing of the case and the date of the final order (the "lag period"). In order to reflect the prevailing level of interest rates during the pendency of the proceeding, Mr. Hevert calculated the average 30-year Treasury yield over the average lag period (approximately 188 days). Mr. Hevert then performed a regression analysis, in which he observed equity risk premium as the dependent variable and the average 30-year Treasury yield as the independent variable.[157]

138. Applying the regression coefficients resulting from that analysis, together with the risk premium and bond yield, Mr. Hevert's initial analysis resulted in a range of ROE results of 10.01 percent to 10.51 percent in his Direct Testimony.[158] His updated Bond Yield Plus Risk Premium analysis produced a range of results from 9.98 percent to 10.39 percent in his Rebuttal Testimony.[159]

v. Qualitative Factors Considered by MERC

139. After completing these quantitative analyses, MERC's witness, Mr. Hevert, considered a number of qualitative factors. These factors include: the relatively small size of MERC; the concentration of transportation volumes on MERC's system; the high level of capital expenditures expected over at least the next three years; and the capital market environment.[160]

140. Mr. Hevert noted that MERC's gas utility operations are significantly smaller than the average for his proxy group companies both in terms of number of customers and annual revenues. Mr. Hevert took MERC's size into account in determining his recommended ROE because, in general, the cost of equity for small firms is subject to a "size effect," carrying greater risks which affect the return required by investors for these smaller companies.[161]

141. Next Mr. Hevert considered that approximately 60 percent of the natural gas delivered by MERC was for 162 transportation customers. In Mr. Hevert's opinion, the high concentration of gas delivered for transportation customers creates an increased risk for MERC because large volume customers have the ability to bypass MERC's system.[162]

142. In addition, Mr. Hevert took into account MERC's capital expenditure plans. MERC plans to invest approximately $118 million of additional capital between 2015 and 2017.[163] Mr. Hevert compared MERC's planned expenditures to those of the proxy group based on a Value Line Investment Survey, and found that MERC has the highest ratio of projected capital expenditures to net plant in that time period.[164] Mr. Hevert concluded that MERC's capital expenditure program is significant and will place additional pressure

[157] Ex. 47 at 38 (Hevert Direct).
[158] Ex. 47 at 39 (Hevert Direct).
[159] Ex. 48 at 43 (Hevert Rebuttal).
[160] Ex. 47 at 40-55 (Hevert Direct).
[161] Ex. 47 at 40-41 (Hevert Direct).
[162] Ex. 47 at 43-44 (Hevert Direct).
[163] Ex. 47 at 44 (Hevert Direct).
[164] Ex. 47 at 44-45 (Hevert Direct).

on its cash flows making regulatory support more important in terms of MERC's ability to finance these expenditures and earn a reasonable return on its planned investments.[165]

143. As discussed above in paragraphs 111-112, MERC's witness, Mr. Hevert, included an adjustment for flotation costs in estimating the ROE for MERC.[166]

144. In addition, Mr. Hevert considered the capital market environment in determining his recommended ROE for MERC. He noted that the models used to estimate the cost of equity are meant to reflect, and therefore are influenced by, current and expected market conditions. According to Mr. Hevert, it is important to assess the reasonableness of any financial model's results in the context of observable market data.[167]

145. Mr. Hevert highlighted the continued uncertainty regarding the Federal Reserve's future policy decisions and the effect of recent Federal Reserve policies on interest rates and the cost of capital.[168] Mr. Hevert also noted that the volatility of stocks in his proxy group has increased since MERC's last rate case, suggesting greater risk associated with investing in the natural utility gas industry.[169]

146. Mr. Hevert stated that because models like the DCF do not incorporate changing market conditions, and interest rates are expected to increase, it is reasonable to consider a broad range of models and data points, as well as capital market conditions, to determine the appropriate ROE for MERC.[170]

vi. MERC's ROE Recommendation

147. Based on his overall evaluation of the quantitative results and qualitative factors, Mr. Hevert concluded that equity investors would require an ROE in the range of 10.00 to 10.60 percent for MERC.[171] Within that range, Mr. Hevert recommended an ROE of 10.30 percent.[172]

148. In making his recommendation, Mr. Hevert did not assign specific weights to the different results or qualitative factors that he considered. Instead, he provided a narrative analysis of the different quantitative and qualitative factors that he took into account in recommending 10.30 percent.[173] In his narrative analysis, he focused on current and expected market conditions and company specific issues. In addition, with regard to the results of his quantitative analyses, Mr. Hevert gave more weight to his

[165] Ex. 47 at 46-47 (Hevert Direct).
[166] Ex. 47 at 47-50 (Hevert Direct).
[167] Ex. 47 at 51 (Hevert Direct).
[168] Ex. 47 at 51-55 (Hevert Direct).
[169] Ex. 47 at 54-55 (Hevert Direct).
[170] Ex. 47 at 55-56 (Hevert Direct); Ex. 48 at 37, 40 (Hevert Rebuttal).
[171] Ex. 47 at 56 (Hevert Direct).
[172] Ex. 47 at 56 (Hevert Direct).
[173] Ex. 47 at 56-57 (Hevert Direct).

Multi-Stage DCF, CAPM, and Bond Yield Plus Risk Premium analyses than to his Constant Growth DCF results.[174]

149. Mr. Hevert stated that his recommended ROE of 10.30 is consistent with returns authorized for other natural gas utilities with whom MERC must compete for capital. Eleven of 22 rate cases decided since June 2014 included ROEs of 10.00 or higher.[175]

150. In Rebuttal Testimony, Mr. Hevert maintained his recommendation of 10.30 percent, even though the results of his quantitative analyses generally decreased from his Initial Testimony to his Rebuttal Testimony when comparable proxy groups were considered.[176] Based on his professional judgment, Mr. Hevert concluded that an ROE of 10.3 percent continued to be supported by his updated analytical results, capital market conditions, company specific factors, and flotation costs.[177]

e. The Department's ROE Analysis

151. In developing a recommended ROE, the Department conducted a Constant Growth DCF analysis and a Two-Growth DCF analysis for its proxy group. The Department's recommended ROE is based on its Two-Growth DCF results, with an adjustment for flotation costs.[178] The Department also performed a CAPM analysis and an ECAPM analysis as a check on its DCF results.[179] The Department did not perform a Bond Yield Plus Risk Premium analysis, concluding that the approach is not a reasonable method of estimating ROE.[180] The Department's analysis is discussed in more detail below.

i. The Department's Constant Growth DCF Analysis

152. As noted above, the Constant Growth Rate DCF model requires the analyst to estimate the expected dividend yield and the long term growth rate for each proxy company included in the analysis.[181] While the Department and MERC used the same basic formula in conducting the Constant Growth DCF analysis for each company in their respective proxy groups, the Department's analysis differed from MERC's analysis in a two respects.

153. First, in calculating the expected dividend yield, the Department's witness, Mr. Kundert, used a 30-day trading period for calculating the Current Stock Price of his proxy companies rather than the 30-, 90-, and 180- trading days approach used by MERC. According to the Department's witness, Mr. Kundert, the 30 day trading period is long enough to avoid short-term aberrations in the capital market. Yet, the 30 day period

[174] Ex. 47 at 57-58 (Hevert Direct).
[175] Ex. 47 at 56 (Hevert Direct).
[176] *See* Ex. 48 at 48 (Hevert Rebuttal); Ex. 413 at 16, Table 10 (Kundert Surrebuttal).
[177] Ex. 48 at 41 (Hevert Rebuttal).
[178] Ex. 412 at 1, 23 (Kundert Direct); Ex. 413 at 2, 3, 11 (Kundert Surrebuttal).
[179] Ex. 412 at 23-29 (Kundert Direct); Ex. 413 at 12-13 (Kundert Surrebuttal).
[180] *See* Ex. 412 at 55-56 (Kundert Direct).
[181] Ex. 412 at 43 (Kundert Direct).

is also short enough to ensure that the measure of the stock price used to calculate the expected dividend yield appropriately reflects all relevant publically available information.[182] In his Direct Testimony, Mr. Kundert calculated the Current Stock Price for each of his proxy companies using closing prices over the 30 trading days ending February 24, 2016.[183]

154. Mr. Kundert chose to use the most recent 30 trading days based on the generally accepted principle that financial markets are efficient. As a result, recent stock prices should fully reflect all publicly available information. In Kundert's view, prices from 90 trading days and 180 trading days may be outdated and result in biased dividend yields that reflect irrelevant information.[184]

155. Second, for the expected growth rate, Mr. Kundert disagreed with Mr. Hevert's used of a Retention Growth rate,[185] but agreed with the use of long-term earnings growth rates from Zacks, Value Line, and Thomson.[186] Mr. Kundert used earnings growth rates from these three investment services because, over the long run, growth in dividend share is derived from growth in earnings, and because the use of projected earnings growth rates is well supported by various financial studies and publications.[187] Mr. Kundert recommended against the use of a retention growth rate because, in his view, the rate is subject to significant estimation error and using earnings per share growth rates is superior to the retention growth rate when doing a DCF analysis.[188]

156. For the Department's Constant Growth and Two Growth (discussed below) DCF analyses, Mr. Kundert estimated the cost of equity for each member of his proxy group using the average of the three growth rates, the highest of the three growth rates, and the lowest of the three growth rates.[189]

[182] Ex. 412 at 16 (Kundert).
[183] Ex. 412 at 16 (Kundert Direct).
[184] Ex. 412 at 44 (Kundert Direct).
[185] Ex. 412 at 44 (Kundert Direct).
[186] Ex. 412 at 14, 43 (Kundert Direct) (noting that Mr. Kundert and Mr. Hevert used growth estimates from the same three investor services – Zacks, Value Line, and Thomson's First Call Consensus).
[187] Ex. 412 at 14-15, 43 (Kundert Direct).
[188] Ex. 412 at 44-45 (Kundert Direct).
[189] Ex. 412 at 13 (Kundert Direct).

157. The results of Mr. Kundert's Constant Growth DCF analysis in his Direct Testimony are summarized below:[190]

Department's Initial Constant Growth DCF Results

Company	Ticker	Low ROE	Mean ROE	High ROE
Atmos Energy Corporation	ATO	9.27%	9.47%	9.58%
Laclede Group, Inc. (The)	LG	7.70%	9.66%	13.28%
Northwest Natural Gas Company	NWN	7.69%	8.71%	10.75%
South Jersey Industries, Inc.	SJI	10.35%	10.86%	11.37%
Southwest Gas Corporation	SWX	6.83%	8.18%	9.87%
WGL Holdings, Inc.	WGL	8.41%	9.86%	10.94%
Average		8.38%	9.46%	10.96%

158. Mr. Kundert noted that these results needed to be adjusted to account for the impact of flotation costs. Mr. Kundert calculated flotation costs in a manner similar to MERC's witness, Mr. Hevert, and estimated flotation costs at 13 basis points. After adding flotation costs, Mr. Kundert arrived at the following results.[191]

Summary of Department's Initial Constant Growth DCF Results
Adjusted for Flotation Costs

Model	Low ROE	Mean ROE	High ROE
Constant Growth Rate DCF	8.51%	9.59%	11.09%

159. In his Surrebuttal Testimony, Mr. Kundert revised his results based on more recent stock prices and dividends, and updated long-term growth estimates from the three investor services (Zacks, Value Line, and Thomson). Mr. Kundert used the same proxy group for the analysis in his Surrebuttal Testimony as he used in his Direct Testimony.[192] Mr. Kundert's updated analysis is based upon financial data as of April 29, 2016.[193]

160. Mr. Kundert also updated his estimate of flotation costs from 13 basis points to 12 basis points. The decrease resulted from the updated stock price and dividend information.[194]

[190] Ex. 412 at 17 (Kundert Direct).
[191] *See* Ex. 412 at 23 (Kundert Direct).
[192] Ex. 413 at 23 (Kundert Surrebuttal).
[193] Ex. 413 at 4.
[194] Ex. 413 at 10-11 (Kundert Surrebuttal).

161. The results from Mr. Kundert's updated Constant Growth DCF analysis, including flotation costs, as discussed in his Surrebuttal Testimony are set forth below:[195]

Summary of Department's Updated Constant Growth DCF Results
Adjusted for Flotation Costs

Low Growth Rate	Mean Growth Rate	High Growth Rate
8.35 percent	9.43 percent	10.94 percent

162. The Department did not propose to use the results from its Constant Growth DCF analyses for the proposed ROE for MERC.[196] Because the growth estimates the Department used from Zacks, Value Line, and Thomson are all five-year growth projections, they may not be reasonable to use as proxies for the DCF's long-term sustainable growth rates.[197] Five-year forecasted growth rates may not be sustainable in the long run, and when they are not, they are not appropriate for use in a Constant Growth DCF model.[198] It is possible that investors have different short-term and long-term expectations in regards to a company's financial performance and earnings growth rate.[199] Therefore, the Department used the Two-Growth DCF model to recommend a reasonable ROE for MERC.[200]

ii. The Department's Two-Growth DCF Analysis

163. Like the Constant Growth DCF model, the Two-Growth DCF model calculates the cost of equity by using a dividend yield and an expected growth rate, except that the Two-Growth DCF model uses a different (second) growth rate after the first five years.[201] As noted above, the Two Growth DCF model accounts for situations where short-term projected growth rates may not be expected in the long-run. The short-term earnings growth rate may be unusually low or high, relative to a company's historical averages, industry averages, or relative to the economy as a whole. Unusually low or high growth rates may result in unreasonably low or high estimates of the cost of equity. The Two Growth DCF addresses these potential limitations by using two different growth rates: one for the short-term and one for the long-term, which represents a sustainable growth rate.[202]

164. In conducting its Two-Growth DCF analysis, the Department used the five-year projected earnings growth rates from Zacks, Value Line and Thomson for the short-

[195] *See* Ex. 413 at 7, 11 (Kundert Surrebuttal) (Constant Growth Surrebuttal Results with 12 basis points added to the Low, Mean, and High results to include flotation costs).
[196] Ex. 412 at 17, 23, 67 (Kundert Direct).
[197] Ex. 412 at 17 (Kundert Direct).
[198] Ex. 412 at 17-18 (Kundert Direct).
[199] Ex. 412 at 18 (Kundert Direct).
[200] Ex. 412 at 23, 67 (Kundert Direct); Ex. 413 at 2-11 (Kundert Surrebuttal).
[201] Ex. 412 at 18 (Kundert Direct).
[202] Ex. 412 at 18 (Kundert Direct).

term growth rate.[203] For long-term growth rates, Mr. Kundert first evaluated whether the growth rates of the companies in his proxy group were sustainable. To determine if a company's growth rate was sustainable, Mr. Kundert calculated the average growth rate for the Department's proxy group, as well as the standard deviation of the growth estimates, and added and subtracted one standard deviation to the average growth rate to develop the upper and lower bounds for long-term sustainable growth rates.[204] If a company's short-term growth rate was more than one standard deviation below (above) the average short-term growth rate of his proxy group, the company's growth rate was considered unsustainable and Mr. Kundert substituted the Department's proxy group average minus (plus) one standard deviation.[205] If a company's growth rate was sustainable (i.e. within one standard deviation of the average growth rate), Mr. Kundert used the same growth rate for the company as he used in the Constant Growth DCF.[206]

165. The results of the Department's initial Two-Growth DCF analysis, without flotation costs, are set forth below:[207]

Department's Initial Two-Growth DCF Results

Company	Ticker	Low ROE	Mean ROE	High ROE
		[1]	[2]	[3]
Atmos Energy Corporation	ATO	8.76%	9.47%	9.58%
Laclede Group, Inc. (The)	LG	7.70%	9.66%	12.19%
Northwest Natural Gas Company	NWN	7.77%	9.09%	10.75%
South Jersey Industries, Inc.	SJI	10.35%	10.86%	11.37%
Southwest Gas Corporation	SWX	6.91%	8.28%	9.87%
WGL Holdings, Inc.	WGL	8.41%	9.86%	10.94%
Average		8.32%	9.54%	10.78%

166. Mr. Kundert adjusted these results to account for the impact of flotation costs.[208] As with his initial Constant Growth DCF analysis, Mr. Kundert recommended a 13 point adjustment to account for flotation costs.[209]

[203] Ex. 412 at 19 (Kundert Direct). These are the same sources as Mr. Kundert used for the Constant Growth DCF analysis.
[204] Ex. 412 at 20 (Kundert Direct).
[205] Ex. 412 at 20 (Kundert Direct).
[206] Ex. 412 at 19-20 (Kundert Direct).
[207] Ex. 412 at 21, JPK-2, Schedules 2-4 (Kundert Direct).
[208] Ex. 412 at 21 (Kundert Direct).
[209] Ex. 412 at 23 (Kundert Direct).

167. The table below sets forth a summary of results of the Department's Two-Growth DCF analysis, including flotation costs, from Mr. Kundert's Direct Testimony:

Summary of the Department's Initial Two-Growth DCF Results
Adjusted for Flotation Costs[210]

Model	Low ROE	Mean ROE	High ROE
Two-Growth-Rates DCF	8.43%	9.67%	10.89%

168. In his Surrebuttal Testimony, Department witness, Mr. Kundert, also updated his Two Growth DCF results because stock prices had changed, some of the proxy companies had raised their dividends, and the three investor services (Zacks, Value Line, and Thomson) had updated their earnings growth estimates.[211] The results of Mr. Kundert's updated Two-Growth DCF analysis, including updated flotations costs, are summarized in the chart below.

Summary of Department's Updated Two-Growth DCF Results
Adjusted for Flotation Costs[212]

Model	Low ROE	Mean ROE	High ROE
Two-Growth-Rates DCF	8.08%	9.11%	10.17%

169. Mr. Kundert identified the drivers of the changes in his DCF results from Direct Testimony to Surrebuttal Testimony. First, updating stock prices and annual dividends lowered the Mean ROE by 15 basis points. It also lowered the Low and High growth ROE scenarios by a similar amount. [213] Second, changes due to updated growth rates accounted for a 40 basis point decrease to the Mean ROE.[214] Finally, the effect of the increases in the share prices and the annual dividends also resulted in a decrease of 1 basis point in the flotation cost adjustment.[215] Together, these three drivers resulted in a decrease of 56 basis points for the Mean ROE from his Direct Testimony to Surrebuttal Testimony.

170. The table below summarizes the updates to the Department's Two-Growth DCF analysis from Direct to Surrebuttal Testimony for the Mean ROE with flotation costs.[216]

[210] *See* Ex. 412 at 23 (Kundert Direct).
[211] Ex. 413 at 1, 4-11 (Kundert Surrebuttal).
[212] *See* Ex. 413 at 10-11 (Kundert Surrebuttal) (showing results without flotation costs on page 10; noting on page 11 that the flotation cost adjustment was revised to 12 basis points on Surrebuttal, down from 13 basis points on Direct; the addition of the 12 basis point flotation cost adjustment on page).
[213] Ex. 413 at 7 (Kundert Surrebuttal).
[214] Ex. 413 at 10 (Kundert Surrebuttal).
[215] Ex. 413 at 10-11 (Kundert Surrebuttal).
[216] Ex. 413 at 11 (Kundert Surrebuttal).

Reconciliation of Changes to the Department's Cost of Equity from Kundert Direct to Surrebuttal (%)

Line	Description	Value	Δ in ROE	% Change
1.	Direct Testimony Recommended Cost of Equity	9.67		
2.	Change due to Increases in Stock Prices and Dividends	(0.15)	-1.6%	-26.79%
3.	Change due to Updated Growth Rates	(0.40)	-4.1%	-71.43%
4.	Change in Flotation Cost Adjustment	(0.01)	-0.1%	-1.79%
5.	Subtotal of Changes to Recommended Cost of Equity from Direct Testimony [Line 2 + Line 3 + Line 4}	(0.56)	-5.8%	
6.	Surrebuttal Testimony Recommended Cost of Equity {Line 1 + Line 5}	9.11		

171. As noted above, the largest change in the DCF results was related to the changes to estimated growth rates for the Department's proxy group as reported by the three investment services. The table below compares the estimated growth rates for the Department's proxy group between Direct Testimony and Surrebuttal Testimony.[217]

Comparison of Average Growth Rates for the Department's Proxy Group by Investment Service[218]

	Direct	Surrebuttal	Nominal Change	Percentage Change
Zacks	5.56	5.62	0.06	1.08%
Thomson	5.58	5.52	(0.06)	-1.08%
Value Line	7.25	6.25	(1.00)	-13.79%

172. As shown above, Value Line's average growth rate experienced the largest change, going down by a full percentage point from 7.25 percent in Mr. Kundert's Direct

[217] Ex. 413 at 10 (Kundert Surrebuttal).
[218] Ex. 412, JPK-2, Schedule 5 (Kundert Direct); Ex. 413, JPK-SR1, Schedule 5 (Kundert Surrebuttal).

Testimony to 6.25 percent his Surrebuttal Testimony. This change moved Value Line's average growth rate closer to the average growth rates of Zacks and Thomson.

iii. The Department's CAPM Analysis

173. The CAPM's basic premise is that any company-specific risk can be diversified away by investors. Therefore, the only risk that matters is the systematic risk of the stock, which is measured by beta.[219]

174. As noted above, CAPM assumes the following:

k = r + beta * (Km – r)

where "k" is the required rate of return on the stock in question, "r" is the rate of return on a riskless asset, and "Km" is the required rate of return on the market portfolio.[220]

175. To perform the CAPM analysis, it is necessary to determine the return on a riskless asset (r), along with the appropriate beta and the appropriate rate of return on the market portfolio.[221]

176. The Department's witness, Mr. Kundert, used the CAPM analysis as a check on the reasonableness of his DCF analysis because there can be difficulty in determining the appropriate beta, appropriate riskless asset, and the effect of taxes. In addition, Mr. Kundert noted that the Commission has historically placed the greatest reliance on the DCF model in estimating a reasonable ROE for a utility.[222]

177. In conducting his CAPM analysis, Mr. Kundert used the average yield on 20-year Treasury bonds for the return on a riskless asset (r). Mr. Kundert noted that the yield on a 90-day Treasury bill is probably the best theoretical proxy for "r" because it is devoid of default risk and subject to a negligible amount of interest rate risk. He recognized, however, that 90-day Treasury bills typically do not match the equity investor's planning horizon. In addition, Mr. Hevert also indicated that the yields on long-term Treasury bonds match more closely with common stock returns, but emphasized long-term yields are exposed to substantial interest rate risk and so are not truly riskless.[223] As a compromise, Mr. Kundert used the average yield on 20-year Treasury bonds over the 30 trading days ending February 18, 2016.[224]

178. Mr. Kundert noted that a 20-year Treasury bond is not a risk-free asset because it incorporates a risk-premium associated with interest rate risk. As a result, using the 20-year Treasury bond may result in an upward bias in the CAPM results.[225]

[219] Ex. 412 at 23 (Kundert Direct).
[220] Ex. 412 at 23-24 (Kundert Direct).
[221] Ex. 412 at 24 (Kundert Direct).
[222] Ex. 412 at 24 (Kundert Direct).
[223] Ex. 412 at 25 (Kundert Direct).
[224] Ex. 412 at 25 (Kundert Direct).
[225] Ex. 412 at 25 (Kundert Direct).

179. For the return on the market portfolio (Km), Mr. Kundert noted that one first has to select a market portfolio. Common choices include S&P 500, the Value Line Composite, or the New York Stock Exchange Index. Mr. Kundert used the S&P 500 as a proxy for the market portfolio.[226]

180. For the beta, Mr. Kundert took the estimates of the beta for each company in his proxy group as provided by Value Line, and used the average as an estimate of the beta for MERC.

181. With these inputs, Mr. Kundert calculated an ROE of 6.09 percent in his Direct Testimony for MERC using the CAPM method (K = 2.36 percent + 0.75 (7.34 percent – 2.36 percent)).[227]

182. In his Surrebuttal Testimony, Mr. Kundert updated his analysis with the most recent data for his inputs, and calculated an estimated ROE of 6.71 percent.[228]

iv. The Department's ECAPM Analysis

183. In addition to the CAPM discussed above, there are other versions of the CAPM that attempt to account for deficiencies of the basic CAPM.[229] According to Mr. Kundert, various empirical studies have shown that for companies with a beta smaller than one (1), the basic CAPM results in a downward bias of the required rate of return compared to the theoretical CAPM.[230] To explain this discrepancy, many studies have postulated that there are other factors, besides beta, that may impact the systemic risk of a common stock.[231]

184. The ECAPM is obtained by estimating the linear relationship between the betas and the required rate of return. To calculate the ECAPM, Mr. Kundert used the same risk-free rate of return, beta, and return on the market portfolio as he used for the simple CAPM.[232] His ECAPM analysis resulted in a required return of equity for MERC of 6.40 percent in his Direct Testimony,[233] and 7.05 percent in his Surrebuttal Testimony.[234]

185. In Mr. Kundert's view, the results produced by his CAPM and ECAPM are too low to be reasonable estimates of MERC's ROE.[235]

[226] Ex. 412 at 26 (Kundert Direct).
[227] Ex. 412 at 24-27 (Kundert Direct).
[228] Ex. 413 at 12 (Kundert Surrebuttal).
[229] Ex. 412 at 27 (Kundert Direct).
[230] Ex. 412 at 27-28 (Kundert Direct).
[231] Ex. 412 at 28 (Kundert Direct).
[232] Ex. 412 at 28 (Kundert Direct).
[233] Ex. 412 at 28 (Kundert Direct).
[234] Ex. 412 at 12 (Kundert Surrebuttal).
[235] Ex. 413 at 13 (Kundert Surrebuttal).

186. Mr. Kundert noted that the significant difference between his CAPM/ECAPM results and his DCF results highlight the difficulties associated with using CAPM/ECAPM to estimate the cost of equity. In addition, Mr. Kundert pointed out that MERC's CAPM results were significantly higher than his. According to Mr. Kundert, these results show how sensitive the CAPM is to the choice of inputs (risk-free market rate, market risk premium, and beta), and therefore can be biased by "noise." For these reasons, Mr. Kundert concluded that the CAPM results should be used only as a check on the reasonableness of DCF results, rather than as a method that is equal to the DCF model.[236]

v. The Department's ROE Recommendation

187. Based on Mr. Kundert's Constant Growth DCF and Two Growth DCF analyses for the Department's proxy group, the Department concluded that the required rate of return for MERC ranged from a low of 8.43 percent for the Two-Growth DCF to a high of 11.09 percent for the Constant Growth DCF, adjusted for flotation costs.[237] Mr. Kundert initially recommended an ROE of 9.67 percent, including flotation costs, based on the result produced by his mean Two-Growth DCF analysis.[238]

188. In Surrebuttal Testimony, Mr. Kundert updated his results and recommended an ROE of 9.11 percent, including flotation costs. The Department's recommendation of 9.11 percent is based on its revised Two-Growth DCF results, using up-to-date market data as of April 29, 2016.[239]

189. The Department did not agree any adjustments should be made for company-specific characteristics or market conditions, concluding that such adjustments were unnecessary to estimate a reasonable ROE.[240]

f. Analysis

190. As noted above, the Commission has historically placed the heaviest reliance on the DCF model in determining the return on equity for ratemaking purposes.[241]

i. Past Commission Decisions Evaluating Similar ROE Analyses

191. In the recent CenterPoint rate case, the Commission again found that the DCF method is an analytically sound method of establishing a reasonable ROE for a public utility.[242]

[236] Ex. 412 at 28-29 (Kundert Direct); Ex. 413 at 13 (Kundert Surrebuttal).
[237] Ex. 412 at 23 (Kundert Direct).
[238] Ex. 412 at 23 (Kundert Direct).
[239] Ex. 413 at 2-11 (Kundert Surrebuttal).
[240] Ex. 412 at 57-65 (Kundert Direct); Ex. 413 at 29-35 (Kundert Surrebuttal).
[241] 2015 CPE RATE CASE ORDER at 38.
[242] 2015 CPE RATE CASE ORDER at 43.

192. In that case, as in this case, the Department recommended that the ROE be determined based on the result of applying the Two-Growth DCF model to the Department's proxy group and adding flotation costs.[243] As part of its analysis, the Department also applied the CAPM to its proxy group, but recommended that the CAPM results be used only as a reasonableness check.[244]

193. CenterPoint, on the other hand, recommended that the ROE be established based on a multi-factor analysis not directly tied to the outcome of any specific analytical model, but based on the professional judgment of its expert.[245] CenterPoint used an approach similar to the approach used by MERC in this case. As part of its analysis, CenterPoint's expert conducted a Constant Growth DCF analysis, a Multi-Stage DCF analysis, a CAPM study, and a Bond Yield Plus Risk Premium analysis.[246] CenterPoint's expert also considered business risks specific to the company, capital market conditions, which he concluded necessitated upward adjustments. CenterPoint's expert weighed both the quantitative results and qualitative information in developing his recommended ROE.[247]

194. Based on a thorough review of the record, the Administrative Law Judge and Commission both concluded that the Department's cost of equity studies were superior to those of CenterPoint.[248] The Administrative Law Judge found that the Department's analysis was analytically sound because of its transparency, historical reliability, replicability, and reliance on publicly available information. Conversely, he found CenterPoint's analysis was more subjective, included unreasonable assumptions, and improperly considered business risks and the capital market as requiring an upward adjustment.[249] For these reasons, the Administrative Law Judge recommended adopting the Department proposed ROE, including flotation costs.[250]

195. The Commission agreed with the Administrative Law Judge's recommendation to set ROE using the Two-Growth DCF model, but decided not to include an adjustment for flotation costs.[251]

196. Similarly, in MERC's last rate case the Commission concluded that the best practice for determining MERC's cost of equity was to rely primarily on the DCF model, and use other models as a reasonableness check.[252] In that case, the Commission rejected MERC's suggestion that the ROE should be set by using multiple analytical models and adjusting the final figures upward to reflect generic and company-specific risk factors. The Commission noted that, in MERC's last two rate cases, the Commission has

[243] 2015 CPE RATE CASE ORDER at 39-40.
[244] 2015 CPE RATE CASE ORDER at 40.
[245] 2015 CPE RATE CASE ORDER at 39.
[246] 2015 CPE RATE CASE ORDER at 39.
[247] 2015 CPE RATE CASE ORDER at 39.
[248] 2015 CPE RATE CASE ORDER at 42-43.
[249] 2015 CPE RATE CASE ORDER at 42.
[250] 2015 CPE RATE CASE ORDER at 42-43.
[251] 2015 CPE RATE CASE ORDER at 43.
[252] 2013 MERC RATE CASE ORDER at 32.

rejected a similar contention by MERC and found no reason to reach a different conclusion.[253] The Commission cited language from a MERC prior order explaining:

> It is not the number of models in the record that ensures a sound decision, but the appropriateness of each model for the purposes at hand, the quality of the data selected as inputs, and the caliber of the analysis applied to the results. Using three models does produce a more detailed record, but it also multiplies the risk of inaccurate inputs and increases the number of points at which subjective judgments are required.[254]

ii. The Department's Analysis is Best Supported by the Record

197. In this case, the record also supports setting the ROE for MERC using the Department's DCF analysis rather than MERC's analysis. The Administrative Law Judge reaches this conclusion for reasons similar to those given by the Commission in the CenterPoint Case and MERC's last rate case.

198. First, the DCF model is a reasonable, market-oriented approach that uses publicly available information to estimate the cost of equity for MERC.[255] The Department's use of the DCF model, specifically the Two-Growth DCF model, to recommend an ROE is analytically sound.

199. In addition, the Department used a sound proxy group and reasonable inputs for its DCF analysis. The Department applied logical criteria to identify comparable companies for its proxy group.[256] The Department used publicly available stock prices and dividend information in its DCF analysis.[257] For its estimate of the expected growth rate in the DCF model, the Department used projected earnings growth rates as reported by three investment services: Zacks, Value Line and Thomson.[258] MERC also used these three well-respected investment services as its source of earnings growth estimates for its DCF analyses.[259]

200. Moreover, the Department's reliance on the DCF model, rather than the CAPM or the Bond Yield Plus Risk Premium model, is consistent with past Commission decisions.[260] The Department properly used the CAPM analysis as a check on its DCF results rather than as the basis for its ROE recommendation. The results of the CAPM

[253] 2013 MERC RATE CASE ORDER at 32.
[254] 2013 MERC RATE CASE ORDER at 32 (quoting from *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-007, 011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (July 13, 2012)).
[255] *See* Ex. 412 at 13 (Kundert Direct).
[256] Ex. 412 at 9-12 (Kundert Direct).
[257] Ex. 412 at 14 (Kundert Direct).
[258] Ex. 412 at 14 (Kundert Direct).
[259] Ex. 47 at 25-26 (Hevert Direct).
[260] *See* 2015 CPE RATE CASE ORDER at 28.

are highly sensitive to the choice of inputs and data sources, as shown by the results in this case.[261] For example, MERC's initial CAPM results were in the range of 9.74 percent to 11.72 percent, whereas the Department's initial CAPM analysis produced a result of 6.09 percent.[262] Likewise, the Bond Yield Plus Risk Premium Model is also volatile and can produce unreliable outcomes.[263]

201. In summary, the Department's cost of equity analysis is transparent, analytically sound, and consistent with past Commission practice.

202. MERC's analysis, on the other hand, lacks transparency and is much more subjective. As discussed above, MERC's witness, Mr. Hevert, recommended an ROE of 10.30 percent in both his Direct Testimony and his Rebuttal Testimony based on quantitative and qualitative information. Mr. Hevert's recommendation in his Direct Testimony considers the results of his DCF, CAPM, and Risk Premium analyses, as well as business risks and capital market conditions, but he does not assign weights to the specific results or factors.[264] As a result, it is not entirely clear how Mr. Hevert arrived at his recommended ROE of 10.30 percent in his Direct Testimony. In Rebuttal Testimony, Mr. Hevert decided to maintain his recommendation of an ROE of 10.30 percent even though his updated results for the DCF, CAPM, and Risk Premium analyses all showed lower ROE estimates.[265] Mr. Hevert did not explain why a lower ROE would not be justified in light of these updated results.[266]

203. In addition, MERC's ROE analysis has other short comings. First, MERC witness, Mr. Hevert, indicated in both Direct and Rebuttal testimony that an upward adjustment should be made to account for business risks faced by MERC such as its small size, revenue concentration, and capital expenditure plans.[267] The record, however, does not support an adjustment to the DCF results for company-specific risks. The use of a proxy group in the DCF analysis is designed to estimate the ROE for a group of companies with comparable risk to MERC.[268] The DCF model relies on the assumption that in a properly constituted proxy group differences between the companies will offset each other.[269] It would be inappropriate to choose a specific factor of the overall investment risk and argue that due to this specific risk factor, MERC's required rate of return is higher than the rate of return for the comparison group.[270] Therefore, no adjustment is necessary for specific business risks identified by

[261] Ex. 412 at 28-29 (Kundert Direct); Ex. 413 at 25-26 (Kundert Surrebuttal).
[262] *Compare* Ex. 47 at 37 (Hevert Direct), *with* Ex. 412 at 27 (Kundert Direct).
[263] 2015 CPE RATE CASE ORDER at 38.
[264] Ex. 47 at 56-58 (Hevert Direct); Ex. 48 at 41-42 (Hevert Rebuttal).
[265] *See* Ex. 48 at 16 (Hevert Rebuttal) (table summarizing Mr. Hevert's updated results using a comparable proxy group for both Direct and Rebuttal testimony analyses).
[266] *See* Ex. 48 at 41 (Hevert Rebuttal).
[267] Ex. 47 at 56 (Hevert Direct); Ex. 48 at 41 (Hevert Rebuttal).
[268] Ex. 412 at 57-58 (Kundert Direct).
[269] Ex. 412 at 57 (Kundert Direct).
[270] Ex. 412 at 59-60 (Kundert Direct).

Mr. Hevert. The Commission reached a similar conclusion regarding company-specific risks in MERC's last rate case.[271]

204. MERC's witness, Mr. Hevert, also concluded that the Constant Growth DCF results did not account for expected changes in capital market conditions and, as a result, multiple analytical models should be used.[272] The record does not support this conclusion or any adjustment to the DCF results on this basis. Stock prices fully account for all publicly available information and, therefore, the stock prices used by the parties in the DCF model should fully reflect investors' expectations about future capital market conditions.[273] The Commission reached a similar conclusion regarding capital market conditions in the recent CenterPoint case.[274]

205. In addition, the Administrative Law Judge agrees with the Department that the record shows MERC's ROE analysis is unreasonable in other regards: 1) Mr. Hevert's use of dividend yields based on 90- and 180-day average stock prices is unreasonable because this information is outdated;[275] (2) Mr. Hevert's use of retention growth rates in his DCF analyses is unreasonable because use of estimated earnings growth is superior to any other growth rates when using a DCF analysis and Mr. Hevert's Retention Growth rate is subject to significant estimation error because it requires estimation of four parameters;[276] (3) Mr. Hevert's assumed long-term payout ratio of 67.67 percent in his multi-stage DCF analyses is unreasonable because it assumes a significant reversal in the trend for industry payouts;[277] and (4) Mr. Hevert's use of 30-year Treasury bonds in his CAPM analysis as a risk-free rate was not shown to be reasonable because the 30-year Treasury bond includes an interest risk rate premium and therefore may bias the CAPM estimated ROE upward.[278]

206. Finally, MERC's witness, Mr. Hevert, notes that his ROE range and recommendation are "highly consistent with the returns authorized for other natural gas utilities with whom MERC must compete for capital: Eleven of the 22 cases decided since June 2014 included ROEs of 10.00 percent or higher."[279] The Commission, however, has found that comparisons to ROE decisions for other utilities are of little probative value in determining the ROE for a particular company because ROE decisions are "by definition specific to the individual utilities, their service areas, and then-prevailing economic conditions."[280] In addition, the Administrative Law Judge concludes that ROE decisions dating back to 2014 are based on stale financial information and therefore should be given little weight in the determination of MERC's ROE.

271 2013 MERC RATE CASE ORDER at 34.
272 Ex. 47 at 44 (Hevert Direct).
273 Ex. 47 at 44, 64 (Hevert Direct).
274 *See* 2015 CPE RATE CASE ORDER at 42-43 (Commission concurring with the Administrative Law Judge's analysis of this issue).
275 Ex. 47 at 43-44 (Hevert Direct).
276 Ex. 412 at 45 (Kundert Direct).
277 Ex. 412 at 48-51 (Kundert Direct).
278 Ex. 412 at 24-26, 52 (Kundert Direct).
279 Ex. 47 at 56 (Hevert Direct).
280 2015 CPE RATE CASE ORDER at 59.

207. For these reasons, the Administrative Law Judge concludes that the Department's ROE analysis, not MERC's analysis, is the most analytically sound and should be used as the basis for the ROE authorized in this case.

iii. Administrative Law Judge's ROE Recommendation

208. As discussed above, the Department recommended an ROE of 9.11 percent. This REO recommendation is based on the Department's updated Two-Growth DCF analysis set forth in Mr. Kundert's Surrebuttal Testimony and includes an adjustment for flotation costs. The recommendation is based on financial information as of April 29, 2016, the most recent information in the record.[281]

209. The Department's final recommendation of 9.11 percent represented a decrease of 56 basis points from the Department's initial recommended ROE of 9.67 percent in Direct Testimony.[282] The Department's recommended ROE in Direct Testimony was based on financial information as of February 24, 2016.[283] Thus, the Department's recommended ROE fell 56 points in just over two months.

210. At the evidentiary hearing, MERC's witness, Mr. Hevert, questioned the reliability of the Department's updated ROE recommendation given the 56 basis point decrease in a relatively short period of time.[284] Mr. Hevert pointed out that the change is largely due to a material revision in Value Line's published growth rate, accounting for 40 points of the 56 point change.[285] Mr. Hevert also noted that on average, the estimated growth rates of the other two sources, Zacks and Thomson, did not change during this same time period.[286] Mr. Hevert suggested that the difference may be due to the fact that Value Line's expected growth earnings are reported in 50 basis point increments and reflect the view of a single analyst, whereas Zacks and Thomson's will often change in as little as one basis point increments and also reflect the consensus view of a number of analysts.[287] Mr. Hevert also noted that other data published by Value Line, such as expected return on shareholder equity and beta coefficients, have remained constant or marginally increased.[288] According to Mr. Hevert, when the totality of the data is considered, it is not entirely clear that the cost of equity could have fallen 56 basis points in just over two months.[289]

211. Mr. Hevert also questioned whether the updated price-to-earnings (P/E) ratio for the Department's proxy companies, which were generally greater than the market

[281] Ex. 413 at 4 (Kundert Surrebuttal).
[282] Ex. 413 at 2 (Kundert Surrebuttal).
[283] Ex. 412 at 16 (Kundert Direct); Ex. 413 at 2 (Kundert Surrebuttal).
[284] Tr. Vol. 2 at 11-15 (Hevert).
[285] Tr. Vol. 2 at 12 (Hevert); Ex. 58 at 2 (Hevert Summary of Testimony).
[286] Tr. Vol. 2 at 12 (Hevert); Ex. 58 at 2 (Hevert Summary of Testimony).
[287] Tr. Vol. 2 at 12 (Hevert); Ex. 58 at 2 (Hevert Summary of Testimony)..
[288] Tr. Vol. 2 at 13 (Hevert); Ex. 58 at 2 (Hevert Summary of Testimony).
[289] Tr. Vol. 2 at 13 (Hevert).

P/E ratio, was consistent with the DCF model. Mr. Hevert pointed out that the DCF model assumes that the P/E relationship will stay in place in the future, but utilities historically have traded at a discount to the market. Mr. Hevert could find no reason why there would be such a fundamental change over the course of just over two months.[290]

212. In response, the Department acknowledged that 40 of the 56 basis point decrease was due to the change in Value Line's estimated growth rate. The Department pointed out, however, that Value Line's updated estimate of 6.25 percent was actually closer to the estimates of Zacks and Thomson (which were in the 5.52-6.62 range) than Value Line's earlier estimate of 7.25 percent.[291] The Department also disagreed with MERC's position that other recent data was inconsistent with the Department's updated DCF results, noting that the DCF results reflect current investor expectations.[292]

213. The Administrative Law Judge recognizes that a 56 point decrease in just over two months is a significant decrease. However, the major driver of that decrease was the reduced growth estimate of one investor service, Value Line. As the Department correctly points out, the decrease moved Value Line's estimated growth rate closer to those of Zacks and Thomson, which were lower than Value Line's estimate in both Initial and Surrebuttal Testimony.[293] As a result, there was greater agreement about expected growth rates from the three investment services (Zacks, Thomson, and Value Line) when the Department conducted its updated DCF analysis than when it did its initial analysis.[294] In the view of the Administrative Law Judge, greater agreement among the investor services is likely to produce a more reliable result.

214. Moreover, MERC did not question the reasonableness of the growth estimates from Zacks or Thomson, which were lower than Value Line's estimate. And in fact, MERC used these same three investor services to obtain estimated growth rates for use in its DCF analyses. For these reasons, the Administrative Law Judge disagrees with MERC's assertion that the Department's updated Two-Growth DCF result is not reasonable.

215. The Administrative Law Judge realizes, however, that in MERC's last rate case the Commission decided to average the Department's initial and updated DCF results where the DCF results had decreased by 11 basis points from Direct to Surrebuttal. In the 2013 rate case, the Department's Surrebuttal estimate was based on closing stock prices for the 32-day period ending on April 14, 2014. The Commission noted that it "cannot set the cost of equity in real time, and routine market fluctuations will inevitably affect its accuracy throughout the period it remains embedded in rates."[295] In that case, the Commission decided to average the two DCF results because it was "concerned about the outsized impact of any one 32-day period." [296]

[290] Tr. Vol. 2 at 13-14 (Hevert); Ex. 58 at 3 (Hevert Summary of Testimony).
[291] Department's Reply Br. at 5 (July 12, 2016) (eDocket No. 20167-123191-01).
[292] *Id.* at 5-6.
[293] *See* Ex. 413 at 9 (Kundert Surrebuttal).
[294] *Id.*
[295] 2013 MERC RATE CASE ORDER at 41.
[296] 2013 MERC RATE CASE ORDER at 41.

216. In this case, the Department's updated analysis used closing stock prices from March 18, 2016 to April 29, 2016, a 42-day period.[297] If the Commission is similarly concerned about an "outsized impact" impact from this 42-day period, the Administrative Law Judge recommends that the Commission average the Department's initial Two-Growth DCF Result of 9.67 percent with the Department's updated result of 9.11 percent.[298] This would result in a recommended ROE of 9.39 percent.

217. Alternatively, if the Commission concludes that the Department's updated Two Growth DCF results best reflect estimated growth rates and investor expectations, an ROE of 9.11 percent would result in a reasonable rate of return for MERC.

218. For the reasons stated above, the Administrative Law Judge concludes the record supports an ROE within the range of 9.11 to 9.39 based on the results of the Department's initial and updated Two Growth DCF analysis.[299] These amounts include the adjustment for flotation costs recommended by the Department.

219. The Administrative Law Judge agrees with the parties that the ROE set by the Commission for MERC should include an adjustment for flotation costs. Both Mr. Hevert and Mr. Kundert testified that recovery of flotation costs is appropriate even if no new issuances of stock are planned in the near future because failure to allow such cost recovery may deny MERC the opportunity to earn its required rate of return in the future.[300] No party, including the OAG, presented testimony to the contrary. In addition, while the flotation cost adjustments calculated by Mr. Hevert and Mr. Kundert resulted in slightly different amounts, MERC did not contest the Department's final recommendation of a flotation cost adjustment of 12 points. The Administrative Law Judge concludes the record supports the inclusion of a 12 basis point adjustment for flotation costs in the final ROE.[301]

220. In conclusion, the Administrative Law Judge recommends that the Commission set MERC's ROE at either 9.11 percent or 9.39 percent, or at another reasonable point within that range.

B. Rate Base Treatment of Regulatory Assets and Liabilities Related to Pensions and Other Benefits

221. MERC's initial filing included, in the proposed test year rate base, nine regulatory asset or liability accounts related to pension and other post-employment

[297] Ex. 413, PJK-SR2, Schedule 6 (Kundert Surrebuttal).
[298] Ex. 413 at 11 (Kundert Surrebuttal).
[299] *See Federal Power Commission v. Conway Corp.*, 426 U.S. 271, 278 (1976) (stating ratemaking is not an exact science, and there is not a single just and reasonable rate, but a "zone of reasonableness").
[300] Ex. 47 at 48 (Hevert Direct); Ex. 412 at 21-22 (Kundert Direct).
[301] The Administrative Law Judge is aware that in the recent CenterPoint case the Commission decided not to include an adjustment for flotation costs in setting the cost of equity for CenterPoint. 2015 CPE RATE CASE ORDER at 43. The record in this case, however, supports the adjustment.

benefits, with a net asset balance of $13,441,441.[302] These accounts are set forth in the table below:[303]

Account	Test Year Balance
128515 Post-Retirement Life Asset	$26,530
128525 Prepaid Pension – Retirement	$5,928,532
182312 Reg Asset-FAS 158	$9,942,914
228300 Def Cr-Sup Ret Select SERP	($175,772)
228305 Supple Remp Ret Plan SERP	$100,000
228310 Pension Restoration	($64,396)
228315 Post Ret Health Care-Admin	($1,785,326)
228320 Post Ret Health Care-Non Admin	($528,103)
Total per DeMerritt Direct p. 45	**$13,444,379**
254490 Reg Liab-FAS 158	($2,938)
Total Pension/Benefits Regulatory Assets/Liabilities	**$13,441,441**

The types of items included in these accounts are, in general, account balances related to the funded status of the pension and other post-employment benefit plans.[304]

222. By way of background, the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 715 requires that companies with defined benefit retirement plans report the overfunded or underfunded status of their plans as a net asset or net liability on the company's balance sheet. The funded status is calculated by taking the difference between the plan's projected benefit obligation and the value of its associated plan assets. This requirement applies to both defined benefit pension and other post-retirement benefit (OPEB) plans.[305]

223. The Department's witness, Ms. Bryne, explained that under the FASB's *prior* guidance structure, Statement of Financial Accounting Standard No. 87 (FAS 87) required companies to record the difference between contributions into the pension plan and pension expense as an asset or liability on its balance sheet. If contributions to the pension plan were less than pension expense, companies recorded an accrued pension

[302] Ex. 414 at 28 (Byrne Direct). Ms. Byrne observed that this amount does not tie to the $13,444,379 mentioned on page 45 of Mr. DeMerritt's Direct Testimony, but she believed that the discrepancy was due to MERC's oversight of not including Account 254490 Reg Liab-FAS 158 in the total. *Id.*
[303] Ex. 414 at 28 (Byrne Direct).
[304] Ex. 414 at 28 (Byrne Direct).
[305] For simplicity, the Department explained that it mostly referred to the pension plan, with the understanding that its discussion applied to other post-retirement defined benefit plans as well. Ex. 414 at 28-29 (Byrne Direct).

liability. If contributions were greater than pension expense, companies recorded a prepaid pension asset. Companies were also required to report the net difference between its pension assets and its pension obligation, or the "funded status," but only in the footnotes to the company's financial statements.[306]

224. The financial reporting guidance for defined benefit plans has changed and is now consolidated in ASC 715 (formally FAS 158). ASC 715 replaced the FAS 87 concept of a prepaid pension asset or accrued pension liability with the requirement to report the funded status on the balance sheet instead of in a footnote. Additionally, some components used to calculate pension expense that were previously held off-balance sheet[307] are now held unrecognized in the accumulated other comprehensive income (AOCI) account in the equity section of the company's financials, until they are recognized as components of pension expense.[308]

225. MERC seeks to treat the funded status of these accounts, plus the AOCI, as regulatory assets and include them in rate base for the 2016 test year.[309]

226. In its testimony, MERC refers to the sum of Account 128525 (Prepaid Pension – Retirement) and Account 182312 (Reg Ass – FAS 158) as its "Prepaid Pension Asset."[310] Account 128525 represents the funded status of MERC's pension plan (the extent to which the value of plan assets exceeds benefit plan obligations), and Account 182312 represents unrecognized gains and losses for all of MERC's benefit plans, which are held in AOCI.[311]

227. The Department disagreed with using the term "Prepaid Pension Asset" to describe MERC's pension related regulatory assets, stating that the term is outdated. The Department's witness, Ms. Bryne, however, agreed to use the term for discussion purposes.[312]

1. Positions of the Parties

228. MERC maintains that it should be allowed to include its Prepaid Pension Asset and OPEB regulatory assets and liabilities in its rate base for the following reasons: (1) contributions to the pension plan and OPEB are an appropriate means of ensuring adequate employee compensation and benefits; (2) the Prepaid Pension Asset provides benefits to MERC's customers, who experience a net savings any time the amortization of the prepaid asset is less than the additional offset to pension expense; (3) due to the timing of when assets are collected and liabilities accrue, there is net negative working

[306] Ex. 414 at 29 (Byrne Direct).
[307] For example, gains and losses, prior service costs or credits, and/or transition assets or obligations remaining from the initial application of FAS 87 could be included in accumulated other comprehensive income. Ex. 414 at 29 (Byrne Direct).
[308] Ex. 414 at 29-30 (Byrne Direct).
[309] Ex. 18 at 3-4 (Nawrot Rebuttal); *see also* Ex. 17 at 13-15 (Nawrot Direct).
[310] Ex. 18 at 3 (Nawrot Rebuttal).
[311] Ex. 415 at 16 (Byrne Surrebuttal).
[312] Ex. 414 at 30 (Byrne Direct).

capital in which MERC is not able to receive a return on funds; and (4) the Prepaid Pension Asset can only be used to pay for employee pension costs.[313]

229. The Department objected to the inclusion of MERC's pension and OPEB regulatory assets and liabilities in rate base. The Department provided several reasons for its objection: (1) the amount in Account No. 128525 (Prepaid Pension - Retirement) simply reflects a reporting requirement to show the funded status of MERC's pension plan, which was previously reported in a footnote; (2) MERC's pension plan assets and benefit obligations may go up or down depending on funding, market conditions, or amendments to the plan, meaning the balances are temporary and ratepayers could be responsible for shortfalls in the future; (3) the Prepaid Pension Asset balance does not necessarily represent only shareholder-provided funds; (4) Account 182312 (Reg Ass – FAS 158) represents unrecognized gains and losses, which may cancel each other out over time, or if they get large enough will be amortized and recovered from ratepayers through pension expense; (5) Account 182312 includes amounts related to all benefit plans, even ones for which the Commission has previously not allowed any expense (e.g., supplemental executive retirement plan (SERP), pension restoration), much less rate base treatment; and (6) regulatory assets and liabilities related to pensions are different from assets traditionally included in rate base in that they do not necessarily represent a cash outlay by the Company, nor do they depreciate or amortize over time like other assets.[314]

230. In addition, the Department pointed out that MERC recovers the cost of providing these benefits from ratepayers through the pension expense (except for those plan expenses such as SERP which the Commission has disallowed altogether). The Department's witness, Ms. Byrne, recognized that there is a timing difference between the cash contribution and pension expense recovered from ratepayers, but also indicated that this difference fluctuates back and forth and should equalize over time.[315]

231. The Department also noted that the Commission rejected a similar proposal by MERC for rate base treatment of its Prepaid Pension Asset in the last rate case.[316] According to Department witness, Ms. Byrne, there are not any changed circumstances that would justify a change in regulatory rate treatment in this rate case.[317]

232. For these reasons, the Department recommended that the assets and liability accounts listed above totaling $13,441,441 be excluded from the test year rate base, with a corresponding adjustment to deferred tax liabilities reflected as an increase in rate base by $5,479,921.[318]

233. In the event the Commission disagrees, the Department recommended excluding Accounts 228300 (Def Cr-Sup Ret Select SERP), 228305 (Supple Remp Ret

[313] Ex. 17 at 13-14 (Nawrot Direct); Ex. 18 at 9 (Nawrot Rebuttal).
[314] Ex. 414 at 33-37 (Byrne Direct); Ex. 415 at 17-29 (Byrne Surrebuttal).
[315] Ex. 414 at 38 (Byrne Direct).
[316] *See* Ex. 415 at 18-19 (Byrne Surrebuttal).
[317] Ex. 414 at 38 (Byrne Direct).
[318] Ex. 414 at 39 (Byrne Direct); Ex. 415 at 15 (Byrne Surrebuttal).

Plan SERP), and 228310 (Pension Restoration), with a corresponding adjustment for deferred taxes. The Department noted that the Commission has previously rejected requests to recover SERP and pension restoration expenses from ratepayers in their entirety, not just in rate base.[319]

234. MERC disagreed with the Department's concerns regarding the Prepaid Pension Asset and other related assets and liabilities. MERC also clarified that it is not requesting to include the Prepaid Pension Asset in rate base only in years when the pension asset increases due to decreased pension expense, but seeks a balanced approach that benefits both shareholders and ratepayers over time.[320]

235. MERC continued to recommend that pension and other related regulatory assets and liabilities be included in rate base.[321] MERC was willing to exclude $118,246 from Account 182312 (Reg Ass – FAS 158) for amounts related to SERP and other post-employment benefits that previously have been disallowed by the Commission.[322] In the alternative, MERC was willing to limit the amounts in rate base to actual company contributions to the Prepaid Pension Asset.[323] MERC noted that the Commission appeared to allow Xcel Energy to include excess actual company cash contributions (over expense) in rate base in its last rate case.[324]

2. Analysis

236. In MERC's last rate case, the Company also sought to include its pension assets in its rate base. The Commission denied MERC's request, explaining that "employee benefits are unlike typical rate-base assets on which a utility is allowed a rate of return; once MERC makes a contribution, it no longer has control over or use of the funds for normal business purposes."[325] The Commission noted that, normally, pension assets are not included in rate base.[326]

237. The Administrative Law Judge agrees with the Department that there is no change in circumstances in this rate case that would justify a different conclusion. As noted by the Department, MERC recovers its allowable pension expense from ratepayers. Thus, it is not being denied recovery of this operating cost.

319 Ex. 414 at 38-39 (Byrne Direct).
320 Ex. 18 at 6-8 (Nawrot Rebuttal).
321 Ex. 18 at 14 (Nawrot Rebuttal).
322 Ex. 20 at 3-4, CMH-R1 (Hans Rebuttal). MERC did not specifically address the Department's alternative proposal to exclude Accounts 228300, 228305, and 228310. Ex. 415 at 28 (Byrne Surrebuttal).
323 Ex. 18 at 14 (Nawrot Rebuttal).
324 Ex. 18 at 13 (Nawrot Rebuttal) (citing *In the Matter of the Application of Northern States Power Co. for Authority to Increase Rates for Electric Service in the State of Minnesota*, MPUC Docket No. E-002/GR-13-868, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (May 8, 2015) (2013 XCEL RATE CASE ORDER).
325 MERC 2013 RATE CASE ORDER at 24.
326 *Id.*

238. In addition, as the Department explained, pension plan assets and benefit obligations may go up or down depending on funding, market conditions, or amendments to the plan. As a result, the balances reflected in the Prepaid Pension Asset are temporary, and fundamentally different than typical rate-base assets.[327]

239. Moreover, the Administrative Law Judge does not find the Commission's decision in the 2013 Xcel Energy Rate Case to be precedential. That case involved an extremely large number of issues. While Xcel Energy apparently was allowed to include excess actual company cash contributions to the pension fund (over expense) in rate base, the question of whether a company's pension asset is properly included in rate base was not specifically litigated by the parties.[328]

240. For these reasons, the Administrative Law Judge agrees with the Department that MERC's pension and employee benefit regulatory assets and liabilities should be excluded from the test year rate base, and that a corresponding adjustment be made to deferred taxes. The Administrative Law Judge recommends that the accounts totaling $13,441,441 (as set forth in the table in paragraph 221) be excluded from the test year rate base, and that a corresponding adjustment to deferred tax liabilities be reflected as an increase in rate base by $5,479,921. This amounts to a net reduction to rate base of $7,961,520.[329]

C. Former Manufactured Gas Plant (FMGP) Costs from IPL

241. On December 8, 2014, in Docket No. G001,011/PA-14-107, the Commission issued an order approving MERC's acquisition of IPL's Minnesota natural gas operations and assets. As part of its Order, the Commission stated that "[u]nrecovered FMGP costs of approximately $2,600,000 paid by IPL may be transferred to MERC and accounted for as a regulatory asset."[330] Consistent with the Commission's decision approving the Asset Purchase Agreement as amended, upon closing, MERC acquired a regulatory asset in the amount of $2,602,565 from IPL. The regulatory asset consisted of deferred costs related to cleanups at several FMGP sites which were incurred by IPL but not yet recovered from ratepayers. MERC also assumed responsibility for future investigation and remediation of costs at the Austin FMGP site.[331]

242. In this proceeding, MERC proposed to recover (1) the value of the FMGP regulatory asset acquired from IPL for FMGP costs incurred but not yet recovered as of

[327] Ex. 412 at 33-34 (Byrne Direct); *see also* Minn. Stat. § 216B.16, subd. 6 ("In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the commission shall give due consideration to evidence of the cost of the property when first devoted to public use, to prudent acquisition cost to the public utility less appropriate depreciation on each, to construction work in progress, to offsets in the nature of capital provided by sources other than the investors, and to other expenses of a capital nature.")
[328] Ex. 18 at 13 (Nawrot Rebuttal); *see* 2013 XCEL RATE CASE ORDER.
[329] Ex. 414 at 39 (Byrne Direct); Ex. 415 at 15 (Byrne Surrebuttal).
[330] *In The Matter of a Request for Approval of the Asset Purchase & Sale Agreement Between Interstate Power and Light Co. and Minn. Energy Res. Corp.*, MPUC Docket No. G001,G011/PA-14-107, ORDER APPROVING SALE SUBJECT TO CONDITIONS at 6 (Dec. 8, 2014).
[331] Ex. 41 at 91 (DeMerritt Direct).

the date of the closing of the acquisition, and (2) MERC's forecasted investigation and remediation costs at the Austin FMGP site for 2015 and 2016. Specifically, MERC proposed to amortize over five years: the $2,602,674 FMGP regulatory asset it acquired from IPL; as well as FMGP costs of $41,470 in 2015 for site assessment and work plan development at the Austin FMGP site; and $144,677 in 2016 for collection of soil and water samples as set forth in the work plan. This would result in a total annual cost of $557,742. MERC also proposed to include approximately $5 million of regulatory assets and environmental liabilities (net zero) in rate base for anticipated future cleanup of the Austin FMGP site.[332]

243. MERC provided testimony of Mr. DeMerritt to demonstrate the reasonableness and prudency of the $2,602,674 FMGP costs paid for by IPL and transferred to MERC as a regulatory asset. MERC also provided annual compliance filings submitted by IPL to the Commission, demonstrating cash outlays for each FMGP site, as well as documentation demonstrating that the past IPL work was undertaken in accordance with plans submitted to and approved by the Minnesota Pollution Control Agency (MPCA) and the United States Environmental Protection Agency.[333]

244. As noted above, MERC also acquired responsibility for the ongoing investigation and remediation at the Austin FMGP site as part of the Asset Purchase and Sale Agreement. At the time MERC became responsible for the Austin site, river sediment needed to be investigated and potentially remediated. Additionally, a plume of tar remained beneath a portion of the site, requiring investigation and remediation.[334] As of September 15, 2015, MERC had prepared a Phase I Environmental Site Assessment and submitted an application to enroll the site in the MPCA Voluntary Remediation Program. For the remainder of 2015 and during 2016, MERC planned to develop and implement work plans to define the extent and magnitude of contamination.[335] MERC also expected that it would have ongoing remediation costs at the Austin FMGP site that could total $5 million, assuming a 30-year monitoring process.[336]

245. No party disputed the reasonableness or prudency of the FMGP costs paid by IPL and included in the $2,602,674 regulatory asset acquired by MERC. Nor did any party challenge the expected costs for the 2015 and 2016 work at the Austin FMGP site.

246. The Department, however, recommended that the Commission end deferral of the FMGP costs as of December 31, 2015 and require MERC to amortize the balance in the deferred account, $2,644,144 ($2,602,674 + $41,470), over five years, amounting to $528,829 per year.[337] The Department's recommended amortization of $528,829 per

[332] Ex. 41 at 30, 91-98, Schedule SSD-33 (DeMerritt Direct); Ex. 416 at 26 (St. Pierre Direct).
[333] Ex. 41 at 92-93, SSD-33 at Schedules 2-3 (DeMeritt Direct).
[334] Ex. 41 at 94 (DeMerritt Direct).
[335] Ex. 41 at 94-95 (DeMerritt Direct).
[336] MERC's Initial Br. at 42 (June 29, 2016) (eDocket No. 20166-122788-01) (citing *In the Matter of a Request for Approval of the Asset Purchase & Sale Agreement Between Interstate Power and Light Co. and Minn. Energy Res. Corp.*, MPUC Docket No. G001,G011/PA-14-107, RESPONSE TO COMMISSION'S ADDITIONAL QUESTIONS FOR JOINT PETITIONERS at Attachment B (July 25, 2014).
[337] Ex. 416 at 28-29 (St. Pierre Direct).

year included the 2015 costs of $41,470, but excluded the 2016 costs of $144,677 from amortization. Instead, the Department recommended that MERC be allowed to recover an annual amount of $144,677 as an FMGP expense in rates until its next general rate case, which reflects MERC's estimated 2016 FMGP costs.[338]

247. The Department also recommended that the $5 million of deferred asset and liability balances for assumed future cleanup of the Austin FMGP site be removed from rate base.[339] The Department stated that MERC failed to provide support for the $5 million figure and, in any event, the deferred account should be based on actual costs.[340]

248. Finally, the Department recommended that the average balance in the deferred account at the end of 2016, $2,379,730, be included in rate base such that MERC would earn a return on the balance.[341]

249. In Rebuttal Testimony, MERC accepted "the inclusion of past and current [FMGP] costs in MERC's 2016 test year as recommended by the Department" and agreed to remove the $5 million of regulatory assets and liabilities from rate base. MERC also clarified that both the IPL regulatory asset and environmental liability should be included in rate base because MERC is effectively acting as a collection agency for IPL and holds a note payable to IPL to reimburse IPL as the collections of revenue for this asset are made. MERC therefore agreed to include the FMGP asset in rate base with recognition that MERC has a corresponding liability as well, resulting in a rate base adjustment of $2,262,976 less than the Department's proposal.[342]

250. MERC disagreed with the Department's recommendation that post-2015 FMGP costs should no longer be deferred and should instead be expensed.[343] MERC asserted that continuation of deferred accounting for ongoing FMGP remediation expense will ensure accurate and transparent accounting of remaining cleanup costs.[344] MERC noted that the Commission previously authorized deferred accounting of cleanup costs by IPL, finding that the costs related to investigation and cleanup of the FMGP sites are

338 Ex. 416 at 29 (St. Pierre Direct).
339 Ex. 416 at 28 (St. Pierre Direct).
340 Ex. 416 at 28 (St. Pierre Direct).
341 Ex. 416 at 29 (St. Pierre Direct).
342 Ex. 45 at 39-40 (DeMerritt Rebuttal).
343 Ex. 45 at 39-40 (DeMerritt Rebuttal).
344 MERC Initial Br. at 41 (June 29, 2016) (eDocket No. 20166-122788-01); Ex. 45 at 40 (DeMerritt Rebuttal).

substantial, extraordinary, and unforeseen,[345] and MERC's proposal would continue that treatment.[346]

251. In Surrebuttal Testimony, the Department agreed that rate base should be decreased by $2,262,976, as it was unaware that MERC was effectively acting as a collection agency for IPL.[347] As a result, all FMGP issues between MERC and the Department were resolved with the exception of deferred accounting for post-2015 FMGP costs.[348]

252. The Department continued to recommend that the Commission end deferral of the FMGP costs as of December 31, 2015. The Department's witness, Ms. St. Pierre, noted that generally deferred accounting is implemented between rate cases and runs until the next rate case.[349] The Department also pointed out that MERC has indicated it expects to file another rate case in 2018 and suggested that if MERC's annual FMGP costs increase significantly from the 2016 test year expense, it could file a deferred accounting petition.[350]

253. While deferred accounting may generally be implemented between rate cases, the Administrative Law Judge concludes that it is appropriate to continue deferred accounting treatment of the FMGP costs for the Austin site because the nature of these costs has not changed. In addition, this treatment is consistent with the Commission's past treatment of these costs.[351]

254. The Administrative Law Judge also recommends that these costs be subject to review for prudence and reasonableness in the next rate case, and that there be no carrying charges allowed on the unamortized deferred balance if the Commission allows

[345] Ex. 41 at 92 (DeMerritt Direct); *In the Matter of a Request by Interstate Power and Light Co. for Deferral of Expenses Associated with Former Manufactured Gas Plants*, MPUC Docket No. G001/M-94-633, ORDER APPROVING REQUEST FOR AUTHORITY TO DEFER COSTS AND REQUIRING FILINGS (Apr. 13, 1995); *In the Matter of the Request by Interstate Power Co. for Deferral of Expenses Associated with Former Manufactured Gas Plants*, MPUC Docket No. G001/M-95-687, ORDER ALLOWING DEFERRAL OF COSTS AND REQUIRING FILINGS (Apr. 2, 1996); *In the Matter of a Request for a Declaratory Ruling for Accounting Treatment of the Recovery of Former Manufactured Gas Plant Clean-Up Costs*, MPUC Docket No. G001/M-06-1166, ORDER ALLOWING RECOVERY OF DEFERRED FORMER MANUFACTURED GAS PLANT CLEAN-UP COSTS at 3 (Mar. 9, 2007)
[346] *See* Ex. 45 at 40 (DeMerritt Rebuttal); *In the Matter of a Request for Declaratory Ruling for Accounting Treatment of the Recovery of Former Manufactured Gas Plant Clean-Up Costs*, MPUC Docket No. G011/M-06-1166, ORDER ALLOWING RECOVERY OF DEFERRED FORMER MANUFACTURED GAS PLANT CLEAN-UP COSTS (Mar. 9, 2007).
[347] Ex. 417 at 17-18 (St. Pierre Surrebuttal).
[348] Ex. 417 at 18 (St. Pierre Surrebuttal).
[349] Ex. 417 at 16 (St. Pierre Surrebuttal).
[350] Ex. 417 at 16-17 (St. Pierre Surrebuttal).
[351] *See In the Matter of the Request by Interstate Power Co. for Deferral of Expenses Associated with Former Manufactured Gas Plants*, MPUC Docket No. G001/M-95-687, ORDER ALLOWING DEFERRAL OF COSTS AND REQUIRING FILINGS (Apr. 2, 1996); *In the Matter of a Request for Declaratory Ruling for Accounting Treatment of the Recovery of Former Manufactured Gas Plant Clean-Up Costs*, MPUC Docket No. G011/M-06-1166, ORDER ALLOWING RECOVERY OF DEFERRED FORMER MANUFACTURED GAS PLANT CLEAN-UP COSTS (Mar. 9, 2007).

future rate case recovery. This recommendation is consistent with the Commission's original decision regarding the Austin FMGP costs.[352]

D. Improved Customer Experience (ICE) Project Costs

255. Prior to MERC's 2013 rate case, MERC's former parent company, Integrys, decided to upgrade the customer information systems (CIS) of MERC and the other five Integrys utilities into a single CIS known as ICE.[353]

256. Since acquiring Integrys in June 2015, WEC has been working, through its subsidiary WEC Business Systems, LLC (WBS), to complete the ICE Project.[354] The Project became operational for MERC on January 25, 2016.[355]

257. In MERC's last rate case, the Commission ordered MERC to defer the present and future ICE development costs as a regulatory asset with the following conditions:

a. The ICE 2016 project expense shall not be included in rate base as the project is not used and useful at this time; MERC did not include the expenses as construction work in progress.

b. Any discussion of amortization period shall be resolved during MERC's next rate case.

c. The deferred expenses shall be subject to a reasonableness review in MERC's next rate case.[356]

258. In this rate case, MERC seeks recovery of the deferred development costs for the ICE Project, as well as ongoing O&M expenses charged from WBS to MERC.[357] The ongoing O&M expenses are comprised of two parts: (1) increased labor and non-labor O&M costs allocated to MERC for ongoing maintenance and licensing costs of the ICE system (Maintenance and Licensing); and (2) depreciation and a return on asset (ROA) charges from WBS to MERC for software associated with the ICE Project (Depreciation Expense).[358]

[352] *In the Matter of the Request by Interstate Power Co. for Deferral of Expenses Associated with Former Manufactured Gas Plants*, MPUC Docket No. G001/M-95-687, ORDER ALLOWING DEFERRAL OF COSTS AND REQUIRING FILINGS (Apr. 2, 1996).
[353] Ex. 21 at 4 (Kage Direct); Ex. 300 at BPL-2 (Lebens Direct). The former Integrys utilities include MERC, Michigan Gas Utilities Corporation, Northern Natural Gas, Peoples Gas Light and Coke Company, Wisconsin Public Service Corporation, and Upper Peninsula Power. Ex. 21 at 5 (Kage Direct).
[354] *See* Ex. 21 at 1, 8 (Kage Direct).
[355] Ex. 414 at ACB-2 (Byrne Direct); Ex. 22 at 8 (Kage Direct).
[356] *In the Matter of a Petition by Minn. Energy Res. Corp. for Auth. to Increase Natural Gas Rates in Minn.*, MPUC Docket No. G-011/GR-13-617, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 58-59 (Oct. 28, 2014).
[357] Ex. 41 at 20, 28 (DeMerritt Direct).
[358] Ex. 41 at 20, 28 (DeMerritt Direct).

259. MERC initially sought to recover approximately $4.6 million in its 2016 test year for the ICE Project. This cost was divided into: $600,821 for deferred development costs incurred before the test year (Development Costs), which reflects a two year amortization of the costs; $1,326,627 for ongoing Maintenance and Licensing; and $2,655,245 in Depreciation Expense.[359]

260. MERC also included a credit of $3,374,963 in the 2016 test year for discontinuing MERC's old CIS, known as the Vertex system.[360]

261. MERC, the Department, and the OAG resolved some of the issues relating to MERC's proposed recovery of ICE Project costs, as discussed below in the Resolved Issues section.[361] Two issues relating to MERC's request remain disputed. First, the OAG has challenged MERC's proposed Depreciation Expense included in the test year for the ICE Project.[362] The OAG maintains that MERC has not shown that the underlying capital costs of the ICE system are reasonable, and recommends a reduction in the Depreciation Expense as a result. Second, the Department and MERC disagree about whether interim measures are needed to address the possibility that WEC might expand implementation of the ICE system beyond the Integrys-legacy utilities to include two WEC-legacy utilities prior to MERC's next rate case.[363] These issues are addressed in turn below.

1. The Reasonableness of ICE Project Costs Included in the Depreciation Expense

262. Prior to implementation of the ICE Project in January 2016, MERC had been operating on a Vertex system. This product was originally developed in the 1980s to run a niche, proprietary hardware platform.[364] MERC implemented the Vertex System in 2006 "as part of a turnkey customer operations outsourcing for MERC."[365] The Vertex system does not have the ability to provide modern levels of customer service and does not meet current standards for data protection, data security, or data accuracy.[366] MERC's agreement with Vertex was scheduled to end in July 2016.[367]

263. Like MERC, the other Integrys utilities were operating outdated systems.[368]

[359] Ex. 41 at 20, 28 (DeMerritt Direct); Ex. 300 at 3 (Lebens Direct). In its pre-filed testimony, the OAG challenged these "Development Costs." After the hearing, however, the OAG informed MERC that it would withdraw this challenge. Accordingly, the OAG no longer challenges MERC's requested recovery for ICE Development Costs.
[360] Ex. 41 at 29, SSD-23 (DeMerritt Direct).
[361] *See* paragraphs 335-354 *infra*.
[362] *See* Issues Matrix at 6-7.
[363] *See* Issues Matrix at 7-8.
[364] Ex. 21 at 4 (Kage Direct).
[365] Tr. Vol. 1 at 38 (Kage).
[366] Ex. 21 at 4 (Kage Direct); Ex. 23 at 17 (Kage Rebuttal).
[367] Ex. 23 at 17 (Kage Rebuttal).
[368] Ex. 21 at 4-5 (Kage Direct); Ex. 50 (Kage Summary of Pre-filed Testimony).

264. The ICE Project was developed to address the limitations of the Vertex system and the legacy-Integrys utility systems, and to obtain internal efficiencies from having all the Integrys utilities on a common technology platform.[369]

265. The ICE Project moves all the former Integrys utilities, including MERC, to a single, modern customer-information system, known as Open-CIS, version 4.0. The ICE platform handles billing, credit and collections, payments, and service order processing. The ICE system also replaces the utilities' telephone systems, web-based self-service, and customer service systems onto a standard technological platform.[370]

266. In addition, the ICE platform provides multiple layers of customer data security that were not previously available with the Vertex system. The increased security includes using tokenization to protect against an external data breach and masking of sensitive data fields to shield against unnecessary internal use.[371]

267. The ICE Project Director, Mr. Kage, testified that the ICE platform would provide a number of benefits, including but not limited to:

- improving MERC's billing and payment operations in a number of ways, such as improving the efficiency and effectiveness of the Bill Estimation process and providing real-time electronic payment information to call centers and web-based self-service channels;

- improving the efficiency and effectiveness of MERC's customer service identification and resolution process such as by improving the online encyclopedia used by call center agents in the process of identifying and resolving customer issues;

- improving MERC's collection efforts through use of a credit model;

- improving customer access to customer specific information by providing web-based self-service channels for customers to use in obtaining and managing the service they receive from MERC that will allow customers to turn off service, schedule service appointments, use bill analyzer tools, and obtain images of past and current bills;

- providing increased security for customer data; and

- improving MERC CIS operating efficiencies.[372]

[369] Ex. 21 at 4 (Kage Direct).
[370] Ex. 21 at 5-6 (Kage Direct); Ex. 23 at 16 (Kage Rebuttal); Ex. 50 (Kage Summary of Pre-filed Testimony).
[371] Ex. 23 at 13 (Kage Rebuttal); Ex. 50 (Kage Summary of Pre-filed Testimony).
[372] Ex. 21 at 5-9 (Kage Direct).

268. The ICE Project was originally estimated to cost approximately $88 million when it was in the development phase in 2013, but the total budget was updated and increased to approximately $118 million in February 2015.[373] The Depreciation Expense included in MERC's test year, however, is based on plant in service of $100,116,229, rather than $118 million, and assigning MERC its proportional share, or 9.83 percent.[374] As a result, MERC's total allocated portion of ICE Project implementation costs is estimated at $9.84 million, or approximately $1.2 million more than initially estimated over the life of the Project.[375]

269. These costs are incurred and depreciated by WBS and will be cross-charged to MERC over 15 years or 3 years (depending on the component) from the in-service date.[376]

270. Mr. Kage explained that the increased costs resulted primarily from the upgrade to the Open-CIS platform being much more complicated than originally anticipated, as well as the resulting increased duration of the ICE Project.[377] The original assumption was that the technology upgrade for Open-CIS was going to be a simple port from an outdated Microsoft DCOM-COM technology to a newer Microsoft.net technology. That turned out not to be the case.[378]

271. According to MERC, the ICE Project still delivers significant value to customers even though the total cost was more than originally estimated. Mr. Kage noted that the increased costs also provided a number of additional features such as: two-layer data security, including masking of key information and tokenization of sensitive information; a better platform for providing information to customers; and call center agents having additional off-peak hours access to customer data to better resolve customer questions.[379]

272. MERC maintained that it took multiple steps to manage the costs after the complexities were discovered, including negotiating contractual mechanisms with the vendor to mitigate costs and changing its internal governance and Project resources where necessary.[380]

273. MERC calculated its cost to implement the ICE Project as $54 per customer (using the $118 million spread across the 2.2 million total customers of the Integrys

[373] Ex. 21 at 8 (Kage Direct).
[374] Ex. 23 at 10 (Kage Rebuttal); Ex. 41 at 28 (DeMerritt Direct). The difference between the $100 million amount and the $118 million budget amount is due to the fact that the ICE platform is not expected to be implemented until later for two of the other former Integrys utilities, People Light and Coke Company and North Shore Gas. These additional dollars are specific to these two utilities and will not be recovered from the other former Integrys utilities. Ex. 23 at 10 (Kage Rebuttal); Ex. 41 at 28 (DeMerritt Direct).
[375] Ex. 23 at 10 (Kage Rebuttal).
[376] Ex. 21 at 10 (Kage Direct).
[377] Ex. 21 at 8 (Kage Direct); Ex. 23 at 12 (Kage Rebuttal).
[378] Ex. 21 at 8-9 (Kage Direct); Ex. 23 at 12-14 (Kage Rebuttal).
[379] Ex. 21 at 9 (Kage Direct); Ex. 23 at 12-13 (Kage Rebuttal); Ex. 50 at 2 (Kage Summary of Pre-Filed Testimony).
[380] Ex. 21 at 12 (Kage Direct).

utilities).[381] MERC asserted that its cost per customer is "lower than the costs of comparable customer information and billing system projects."[382]

274. MERC relied on a 2015 industry study done by Navigant Research (Navigant Report) to support its claim, stating that the Navigant Report shows "an average per meter cost for an upgraded customer information/billing system for a midsize utility such as MERC to be approximately $70 [per] meter to $100 per meter."[383] MERC also noted that the Navigant Report stated that DTE Energy, a public utility based in Detroit, was in the process of implementing a new CIS for its 3 million customers at an expected cost of $70 plus per customer.[384]

a. The OAG's Concerns Regarding the ICE Project Costs

275. In its Direct Testimony, the OAG recommended that MERC be denied recovery of costs beyond MERC's share of the initial $88 million estimate. The OAG asserted that MERC had not demonstrated that it was prudent to increase the ICE Project budget by more than $30 million in February 2015, and MERC had not shown that the increased ICE Project budget provided a good result for ratepayers.[385]

276. The OAG did not dispute the causes of the increased costs cited by MERC.[386]

277. Instead, the OAG questioned MERC's claim that the ICE Project would provide a number of benefits through efficiencies and improved processes. The OAG pointed out that the Company failed to quantify those benefits by the Federal Energy Regulatory Commission (FERC) account or include them in the test year, other than the savings from discontinuing the Vertex contract. The OAG expressed concern that MERC was asking its customers to pay for the ICE Project but was not reducing other costs such as billing and customer service to reflect the claimed benefits from the ICE Project.[387]

278. In addition, the OAG maintained that an updated Net Present Value Revenue Requirements (NPVRR) analysis for the ICE Project showed that the ICE Project was not cost-effective. The OAG explained that in the 2013 rate case, MERC analyzed three different options that had been considered for the ICE Project. The three options produced the following NPVRR results: (1) a positive NPVRR of $37.2 million, (2)

[381] Ex. 21 at 11 (Kage Direct). The OAG calculated the cost per meter at roughly $43 per meter. The OAG arrived at this cost by dividing MERC's $9.8 million portion ICE Project costs by its customer count of 231,000. *See* OAG's Initial Br. at 11 (June 29, 2016) (eDocket No. 20166-122790-01). The OAG's calculation is a more accurate estimate of the cost per customer that MERC is proposing to recover.
[382] Ex. 21 at 11 (Kage Direct).
[383] Ex. 21 at 11 (Kage Direct).
[384] Ex. 21 at 11 (Kage Direct).
[385] Ex. 300 at 11 (Lebens Direct).
[386] Tr. Vol. 1 at 183 (Lebens).
[387] Ex. 300 at 7-10 (Lebens Direct).

a negative NPVRR of $1.4 million, and (3) a positive NPVRR of $19.7 million. Integrys (now WEC) chose the first option, which had the greatest NPVRR, at $37.2 million.[388]

279. In this case, MERC updated the NPVRR for the ICE Project to reflect the increased budget.[389] The updated NPVRR was $5.4 million, rather than the $37.2 million that MERC had estimated in the last rate case.[390] Given that the results of the 2013 NPVRR showed another option with a NPVRR of $19.7 million and the updated NPVRR for the option chosen was $5.4 million, the OAG asserted that MERC had failed to provide a sufficient explanation to justify the approximately $30 million increase in the ICE Project.[391]

280. The OAG noted that the additional benefits to the CIS that MERC claimed were attributable to the $30 million increase (improved data security, improved usability for frequently used windows, and additional off-peak access for call center agents) are largely unquantifiable. The OAG asserted that MERC had not demonstrated that a budget increase of $30 million was required to achieve these results.[392]

281. For these reasons, the OAG concluded that MERC had not demonstrated that it was prudent or reasonable to increase the ICE Project budget by approximately $30 million and recommended that MERC not be allowed to recover the increase in the ICE Project costs above the original $88 million budget.[393]

282. In Rebuttal Testimony, MERC disagreed with the OAG's assertion that it had not adequately justified the costs for the ICE Project. MERC emphasized that the ICE Project was implemented because the Vertex system was outdated and the Company had no choice but to update its CIS. MERC asserted that the ICE Project is necessary for MERC to function as a utility and to meet its customers' needs for up-to-date data security and customer service. MERC also contended that the increased costs were necessary to complete the ICE Project, given that MERC's prior system had to be replaced. MERC noted that it had already invested significant resources in the Project. MERC's witness, Mr. Kage, also asserted that "[a] utility of MERC's size would not have been able to achieve a solution of this scale and with this level of benefit to customers at the current cost level."[394] Based on the Navigant Report, MERC claimed "a utility the size of MERC would typically spend $100/customer to implement a CIS solution."[395]

283. In addition, MERC noted that the updated NPVRR analysis showed that the NPVRR of the ICE Project remains positive compared to the pre-existing outsourced (and outdated) Vertex CIS.[396] MERC disagreed with the OAG's claim that the NPVRR of the

[388] Ex. 300 at 8, Schedule BPL-2 at 8-9 (Lebens Direct).
[389] Ex. 300, BPL-2 at 2 (Lebens Direct).
[390] Ex. 300, BPL-2 at 2, 8 (Lebens Direct).
[391] Ex. 300 at 10 (Lebens Direct).
[392] Ex. 300 at 11 (Lebens Direct).
[393] Ex. 300 at 11 (Lebens Direct).
[394] Ex. 23 at 15 (Kage Surrebuttal).
[395] Ex. 23 at 15 (Kage Surrebuttal).
[396] Ex. 23 at 15 (Kage Surrebuttal).

ICE Project is lower than that of another option evaluated as part of the 2013 rate case. MERC asserted that the OAG's analysis fails to recognize that the same issues that caused costs to increase for the ICE Project as implemented would have also affected the option pointed to by the OAG because that option, like the current project, also involved a move to the Open-C platform.[397] MERC reiterated that the primary driver of the cost increases was the increased level of complexity associated with moving to the Open-C platform. As a result, the increases related to the Open-C platform are equally applicable to the other option, making the 2013 NPVRR results outdated.[398]

284. MERC also contended that WBS took steps to control costs. According to MERC, in light of the issues with the initial estimate and the scope of work, WBS engaged with the vendor to obtain concessions.[399] WBS took the following actions: (1) continuous tracking and management of project status and implementation; (2) contract negotiations to obtain reduced-cost or free work; and (3) amendments to the management process.[400] MERC provided all of the company's project management files, and weekly and monthly status reports from 2012 to the beginning of 2016 to the OAG.[401]

285. Finally, MERC disagreed with the OAG's argument that customers will not realize the benefits from the increased ICE Project costs in the test year. MERC noted that customers began to realize the benefits of improved web and telephone service, improved customer data security, and improved access to data to enhance customer service immediately upon the ICE Project's implementation in January 2016. MERC contended that such benefits, resulting in customer security and satisfaction, are valuable but simply cannot be fully quantified. In addition, while ICE was implemented for MERC in early 2016, "stabilization of the new platform will not occur until 2017. As such, cost saving [from the ICE platform], would likely be realized after the 2016 test year of the current case." In contrast, the cost savings relating to the Vertex contract are quantified and are included in the test year.[402]

286. In Surrebuttal Testimony, the OAG continued to assert that MERC had not demonstrated that the cost increase in the ICE Project was prudent and reasonable. The OAG found Mr. Kage's response regarding quantification of costs and the NPVRR analysis unpersuasive. The OAG noted that MERC did not provide projected savings for any of the categories by FERC account, and only provided an updated NPVRR for the current option, not the other options analyzed in the 2013 rate case.[403]

287. In addition, in Surrebuttal Testimony, the OAG disagreed with MERC's characterization of the Navigant Report. According to the OAG's witness, Mr. Lebens, the Navigant Report actually supports its position, not MERC's position regarding the cost

[397] Ex. 23 at 19-20 (Kage Rebuttal).
[398] Ex. 23 at 19-20 (Kage Rebuttal).
[399] Ex. 23 at 20-21 (Kage Rebuttal).
[400] Ex. 23 at 22 (Kage Rebuttal).
[401] Ex. 23, Schedule R-3 (Kage Rebuttal); Tr. Vol. 1 at 185 (Lebens).
[402] Ex. 23 at 17-18 (Kage Rebuttal); Ex. 300, BPL-2 at 1-2 (Lebens Direct).
[403] Ex. 302 at 12-13 (Lebens Surrebuttal).

of the ICE Project.[404] Mr. Lebens claimed that the $100 cost estimate referred to by MERC's witness, Mr. Kage, applies to midsize utilities. According to Mr. Lebens, "[t]he study explains that midsize and large utilities face certain cost pressures because only two vendors provide CIS solutions suitable for utilities with more than 300,000 customers. MERC, however, only has approximately 230,000 customers, meaning it does not face the two-vendor limitation."[405]

288. The OAG also stated that the study indicates that "'[s]olutions geared toward smaller utilities may run just half the cost of large implementations.'" In addition, the study further notes that one vendor "has developed a simplified package/integration for midsize utilities, which it says is closer to the $25 to $30 per endpoint."[406] Based on the information in the study, the OAG concluded that the study suggests "[n]ot only that MERC could obtain a sufficient solution at a lower cost, but also that it may not be benefiting from 'economies of scale' by partnering with the other WBS utilities, as Mr. Kage claims."[407]

289. The OAG noted that MERC and Integrys did not evaluate a MERC-only CIS solution when deciding to replace MERC's Vertex system. Instead, only Integrys-wide solutions were examined.[408]

290. Based on the $25 to $30 per customer installation cost referenced in the Navigant Report, the OAG recommended that MERC be allowed recovery of $27.50 per customer or a total project budget of $6,352,500, rather than the $9.84 million referenced in paragraph 268 above.[409] The OAG calculated the adjustment amount by multiplying MERC's customer count of 231,000 by the mean of the $25-30 cost range ($27.50) provided in the Navigant Report. The OAG asserted that its recommendation is reasonable because MERC did not consider a stand-alone option or investigate the cost to serve only MERC.[410] In the alternative, the OAG continued to recommend that the Commission reduce MERC's ICE Project recovery to its original budget of $88 million.[411]

291. MERC opposed both of the OAG's proposed adjustments to the ICE Project cost. MERC stated that the $25 to $30 per meter solution noted in the Navigant Report was "less sophisticated" than the more comprehensive solution MERC obtained by partnering with other Integrys-legacy utilities, and would actually degrade the level of customer service MERC has historically provided its customers.[412] MERC's witness, Mr. Kage, stated that several important CIS functions which are part of the ICE solution would not be available with a $25 to $30 per meter option, including:

[404] Ex. 302 at 14-17 (Lebens Surrebuttal).
[405] Ex. 302 at 16 (Lebens Surrebuttal).
[406] Ex. 302 at 16 (Lebens Surrebuttal).
[407] Ex. 302 at 17 (Lebens Surrebuttal).
[408] Ex. 302 at 17 (Lebens Surrebuttal).
[409] Ex. 302 at 20 (Lebens Surrebuttal).
[410] Ex. 302 at 20-21 (Lebens Surrebuttal); Ex. 24 at 10 (Kage Rebuttal) (stating MERC requests recovery of $9.84 million of implementation costs over the life of the assets).
[411] Ex. 302 at 20 (Lebens Surrebuttal).
[412] Ex. 50 at 2 (Kage Summary of Pre-Filed Testimony).

- Billing for MERC's large customers, primarily transportation customers;
- Changes to the bill format;
- Electronic routing and dispatching of service orders;
- More varied billing options such as e-bill;
- Functionality for meter and device asset management; and
- Contact Center IVR and Web Self Service functionality.[413]

292. MERC's witness, Mr. Kage, also asserted that the platform MERC selected was necessary to protect customer data, including data masking of key information, tokenization of sensitive information, and more secure storage of customer information.[414] Further, selection of a stand-alone option would also have required MERC to incur the costs of having its own Information Technology (IT) department and customer call center, and would have resulted in less customer service and less customer protection functionality.[415] MERC also noted the Navigant Report estimated the average utility cost in the range of $65 to $75 or even $80 per meter.[416] MERC continued to support recovery of ICE Costs as discussed above, asserting the ICE Project "provides good value to MERC customers at a closely-managed, fair, and reasonable price."[417]

b. Analysis

293. To recover expenses for the ICE Project, MERC has the burden to demonstrate that the expenses are reasonable and prudently incurred.[418]

294. The Administrative Law Judge concludes that MERC has shown by a preponderance of the evidence that it was necessary for MERC to update its CIS system because the Vertex system was outdated. Continuing with the Vertex system was not a reasonable option.

295. The Administrative Law Judge also concludes that MERC has shown by a preponderance of the evidence that the ICE Project provides a positive value for MERC customers. While the NPVRR is not as great as initially anticipated in 2013, the current NPVRR shows the ICE Project provides real value to customers. The Administrative Law

[413] Ex. 50 at 2-3 (Kage Summary of Pre-Filed Testimony).
[414] Ex. 50 at 3 (Kage Summary of Pre-Filed Testimony).
[415] Ex. 50 at 1(Kage Summary of Pre-Filed Testimony).
[416] Ex. 50 at 2 (Kage Summary of Pre-Filed Testimony).
[417] Ex. 50 at 3(Kage Summary of Pre-Filed Testimony); *see also* Tr. Vol.1 at 192-193 (Lebens).
[418] *See* Minn. Stat. § 216B.16, subd. 4; *In the Matter of the Petition of Interstate Power Company for Auth. to Increase its Rates for Elec. Serv. in Minn.*, 416 N.W.2 800, 806 (Minn. 1987), *rev. denied* (Feb. 17, 1988) (stating "prudency of investment is a fundamental consideration in determining whether a utility's proposed rates are just and reasonable.")

Judge finds the 2013 NPVRR numbers for all options would have gone down significantly, not just the NPVRR for the option chosen, given that the primary driver of the cost increases was common to all options.

296. In addition, the record shows that the ICE Project provides important data protection and Web-based customer service features. In the view of the Administrative Law Judge, the increased data security and Web-based customer service applications provided by the ICE Project are important to customers today.

297. While the record supports these conclusions, the Navigant Report also calls into question whether MERC could have adopted a stand-alone CIS solution that was less costly than the ICE Project. MERC correctly notes that the Navigant Report states that the average cost of a new CIS is between $65 and $75 per meter,[419] and WEC's cost for the ICE Project was $54 per customer.[420] Yet, the $65 to $75 range is simply an average cost for all investor-owned utilities.[421] As the OAG pointed out, the Navigant Report also suggests that utilities with less than 300,000 customers, like MERC, may be able to obtain more cost-effective CIS solutions, including solutions for less than $54 per customer.[422]

298. While MERC's witness, Mr. Kage, claims that MERC could not have obtained a system comparable to the ICE platform for $25-30 per customer, he does not provide any data to support his assertion.[423] Nor does he provide a detailed estimate of what a MERC-only solution would cost. Moreover, the record is clear that MERC and Integrys did not investigate a MERC only option, much less obtain any bids to determine how much a comparable MERC-only solution would cost, when Integrys and MERC decided to replace the Vertex system.[424] Taken as a whole, the Administrative Law Judge concludes that there is insufficient evidence to conclude that the ICE Project was more cost effective than a comparable MERC-only solution.

299. MERC maintains that a MERC-only solution was not viable because Integrys sought to implement an Integrys-wide solution for all of its utilities.[425] While Integrys (now WEC) was certainly free to adopt and implement an Integrys-wide solution, MERC's customers should not be required to pay a premium for an Integrys-wide solution if a comparable MERC-only system would have been less expensive. Rates including such a premium would not be reasonable. As a result, MERC has not yet shown that the full $9.84 million in ICE Project costs that it seeks to recover from MERC's ratepayers (through depreciation and ROA charges from WBS) are reasonable and were prudently incurred.

[419] Ex. 50 at 2 (Kage Summary of Pre-filed Testimony); Ex. 22, BEK-2 at 6 (Navigant Report).
[420] Ex. 21 at 11 (Kage Direct).
[421] Ex. 22, BEK-2 at 6 (Navigant Report).
[422] OAG Initial Br. at 14 (citing Ex. 22, BEK-2 at 11 (Navigant Report)).
[423] Ex. 50 at 2-3 (Kage Summary of Pre-Filed Testimony).
[424] Ex. 302, BPL-SR-2 (Lebens Surrebuttal).
[425] *See* Ex. 302, BPL-SR-2 (Lebens Surrebuttal).

300. While the Administrative Law Judge agrees with the OAG that MERC has not yet demonstrated that the increased costs for the ICE Project are reasonable, the Administrative Law Judge recommends that the Commission adopt a different approach to adjusting the ICE Project costs than the two adjustments proposed by the OAG. Because the ICE Project is a valuable replacement of the Vertex system, the costs for the ICE Project should be allowed to the extent that they are less than a MERC-only solution. If a MERC-only solution proves more costly than MERC's portion of the ICE Project, then MERC should be allowed full recovery of MERC's portion of the ICE Project cost. For these reasons, the Administrative Law Judge recommends that the Commission require MERC to file a detailed estimate of the cost of a comparable MERC-only CIS, including any additional IT personnel costs or other costs arising from a MERC-only solution. The cost estimate should be from a vendor chosen in consultation with the Commission and interested parties.

301. Until such a filing is made and reviewed, the Commission could allow recovery of the ICE Project costs as currently proposed by MERC, subject to true-up if necessary after comparison to a MERC only-option. Alternatively, the Commission could provide for deferred accounting treatment of the ICE Project costs until MERC's next rate case and determine the appropriate level of recovery in that rate case after considering the cost of a MERC-only option.

302. In the Administrative Law Judge's view, the OAG's suggestion to cap MERC's recovery at $27.50 per customer is not supported by the Navigant Report because the $25 to $30 figure in the Navigant Report is a general estimate.[426] There is no evidence in the record to demonstrate that MERC actually could have implemented a CIS that provided the necessary functionality and data protection for $27.50 per customer. The OAG's witness, Mr. Lebens, who recommended the $27.50 figure is not a computer expert but rather is a financial expert, and therefore could not opine as to whether MERC could actually purchase a system comparable to ICE for $27.50 per customer.[427]

303. Similarly, the OAG's suggestion to cap recovery at the initial $88 million estimate amount is not supported by the record. As noted above, MERC has demonstrated that the ICE Project provides substantial value and important functionalities, such as data security, that were not available with the old Vertex system. In summary, the record supports recovery of ICE Project capital costs to the extent those costs are not greater than the cost of a comparable MERC-only solution.

2. Implementation of ICE for WEC-Legacy Utilities

304. As discussed above, Integrys began development of the ICE platform for use by its six legacy utilities. WEC continued implementation of the ICE Project for the former Integrys utilities after WEC acquired Integrys.[428]

[426] Ex. 22, BEK-2 at 1, 11 (Kage Direct).
[427] Ex. 300 at 1 (Lebens Direct).
[428] Ex. 21 at 4-5 (Kage Direct).

305. WEC owns two other legacy utilities, Wisconsin Gas and Wisconsin Electric Power Company (Wisconsin Electric). WEC currently has no plans to transition Wisconsin Gas or Wisconsin Electric to the ICE platform.[429] In a January 2016 response to an Information Request from the Department, WEC noted that its current focus is on implementation of the ICE system for the legacy Integrys utilities, and on stabilizing the solution for these utilities in 2017. According to WEC, initiating and implementing ICE for Wisconsin Gas and Wisconsin Electric would be a complex, multi-year project.[430]

306. Notwithstanding MERC's response, the Department observed that it was unlikely that WEC would not have its two WEC-legacy utilities transition to ICE given the $118 million investment in the ICE Project. The Department's witness, Ms. Byrne, expressed concern that the decision to integrate the WEC-legacy utilities to the ICE system could be made between rate cases or after MERC's ratepayers have paid a significant portion, if not all, of the costs for the ICE system through rates.[431]

307. To address this concern, the Department made two recommendations. First, the Department recommended that MERC provide an update in the initial filing in its next rate case on the decision process for WEC-legacy utilities to implement the ICE system, fully justifying any decision for the WEC-legacy utilities not to use ICE. If a process has been implemented to either explore the idea, or an actual timeline has been established for WEC-legacy utilities to adopt ICE, the Department recommended that MERC provide a detailed discussion of the status, along with a proposal to reimburse Minnesota ratepayers for their share of the ICE system (deferred and ongoing costs). If MERC does not provide this information in its initial filing in its next rate case, the Department recommended that the initial rate case filing be considered incomplete.[432]

308. Second, the Department recommended that should WEC decide to transition WEC-legacy utilities to the ICE system before MERC's next rate case, MERC should charge the WEC-legacy utilities for the difference in MERC's allocation of all allowed ICE costs (deferred and ongoing), as if those WEC-legacy utilities adopted ICE at the same time as the Integrys-legacy utilities. The Department proposed that this revenue be tracked in a regulatory liability to provide an opportunity for the Commission to set a refund mechanism for Minnesota ratepayers in MERC's next rate case.[433] This proposal is intended to ensure that MERC's customers do not pay more than their fair share of the ICE system costs.[434]

309. MERC did not object to providing an update in its next rate case as to whether other WEC utilities will adopt ICE.[435]

[429] Ex. 414 at 14, ACB-6 (Byrne Direct) (attaching MERC's response to DOC IR No. 178).
[430] Ex. 414 at 14, ACB-6 (Byrne Direct) (attaching MERC's response to DOC IR No. 178).
[431] Ex. 414 at 15 (Byrne Direct).
[432] Ex. 414 at 15 (Byrne Direct).
[433] Ex. 414 at 16 (Byrne Direct).
[434] *See* Ex. 414 at 15-16 (Byrne Direct).
[435] Ex. 23 at 8 (Kage Rebuttal).

310. MERC disagreed with the Department's proposed interim measures. According to MERC, the interim measures are not warranted for several reasons. First, MERC witness, Mr. Kage, stated that WBS has no current plans to implement ICE for the WEC-legacy utilities. Second, he explained that it would be impossible to implement ICE for the WEC-legacy utilities for at least three years due to the complexity of the change, the costs involved, and the work that would have to be done to make ICE feasible for these utilities. Third, in the event WEC adopts some form of ICE for its legacy utilities, Mr. Kage maintained that WEC would incur substantial additional costs that were not then factored into the Department's proposal. Finally, Mr. Kage claimed that there are a number of additional factors that should be considered before any deferral or cost-sharing amount is implemented, including whether WEC utilities would get the same benefits over the same number of years that MERC will receive for implementing the ICE system earlier. For these reasons, MERC concluded that it would be premature to implement requirements for deferral or cost allocation.[436]

311. In Surrebuttal Testimony, the Department continued to recommend that the Commission adopt both of its recommendations: an update with the next rate case filing and interim measures. The Department noted that if WEC did not take any steps to transition WEC-legacy utilities to the ICE system before MERC's next rate case, then MERC would have no requirements other than the update. If, however, Mr. Kage's prediction regarding implementation for the WEC legacy utilities proves inaccurate, then the Department believes its proposed interim measures are important to ensure that MERC's ratepayers have an opportunity to be appropriately reimbursed for development costs of a system that has wider use in practice.[437]

312. The Administrative Law Judge agrees with the Department that it is reasonable to require MERC to provide an update in its next rate case regarding the decision process for WEC-legacy utilities to implement the ICE system. The Administrative Law Judge recommends that the Commission require MERC to provide the update requested by the Department in its initial filing in its next rate case, and if it fails to do so its application should be deemed incomplete.

313. The Administrative Law Judge concludes that it would be premature to require the interim cost allocation measures proposed by the Department. As noted by MERC, the implementation of ICE to other WEC utilities is not presently planned and may not happen, if at all, for several years. In addition, MERC indicated that there are additional costs for WEC that were not factored into the Department's proposal and there are other issues that should be considered before any deferral or cost-sharing is implemented such as whether the WEC-legacy utilities would get the same benefits over the same number of years as MERC. The Administrative Law Judge agrees these issues should be addressed before any deferral or cost-sharing is implemented by the Commission.

[436] Ex. 23 at 8-9 (Kage Rebuttal).
[437] Ex. 415 at 8 (Byrne Surrebuttal).

314. Instead of adopting the Department's proposed interim measures, the Administrative Law Judge recommends that in the event that WEC decides to implement the ICE system for its WEC-legacy utilities *prior to* MERC filing its next rate case, MERC should be required to make a filing within 30 days of such a decision. The filing should provide details of WEC's implementation plans and a proposal for adjusting the costs paid by MERC's customers for the ICE system to ensure the costs paid by MERC's customers are reasonable. If such a filing is made prior to the next rate case, the Commission can determine, at that time, whether to revise the contents of the filing to be made by MERC in its next rate case as discussed above in paragraph 312.

E. Uncollectible Expense

315. MERC, the Department, and the OAG disagree on the uncollectible expense for the test year.

1. The Positions of the Parties

316. In its initial filing in this case, MERC calculated the 2016 test year uncollectible expense based on a three-year average of uncollectible expense for the period 2012–2014, which yielded a percentage of 0.578605 of tariffed revenues. MERC then applied this percentage to the 2016 test year forecasted tariffed revenues plus an assumed rate increase of $14 million, for a total forecasted uncollectible expense of $1,655,543 for the 2016 test year.[438]

317. The Department recommended that, instead of using a three-year historical average, the Commission use MERC's 2015 rate of 0.459362 percent of tariffed revenues to calculate the uncollectible expense. The Department maintains that use of the 2015 uncollectible rate will more accurately reflect actual uncollectibles in the 2016 test year because there has been a consistent downward trend and gas costs are lower than forecasted for 2015.[439]

318. The Department calculated the test year expense in a manner similar to MERC, but using the actual 2015 uncollectible rate. The Department's witness, Ms. St. Pierre, multiplied the actual 2015 uncollectible expense ratio of 0.459362 percent by the test year tariffed sales revenue of $263,176,664 (reduced by the base cost of gas revisions of $8,447,852) and the revenue deficiency amount, rounded up to the nearest million ($6 million) to determine the test year amount. Based on her calculations in Direct Testimony, she recommended that the Commission reduce the test year revenue requirement by $397,589 for uncollectible expense.[440]

319. MERC proposed to use non-labor inflation factors in the calculation of MERC's uncollectible expense, and Ms. St. Pierre similarly recommended that the

[438] Ex. 41 at 36-37, SSD-12 (DeMerritt Direct).
[439] Ex. 416 at 43 (St. Pierre Direct).
[440] Ex. 416 at 40-44 (St. Pierre Direct); Ex. 417 at 27 (St. Pierre Surrebuttal).

Commission require MERC to calculate its test year uncollectible expense based on the non-labor inflation rates ultimately approved in this rate case.[441]

320. Like the Department, the OAG also recommended that MERC's test year expense be set using the 2015 uncollectible rate rather than a historical average. The OAG, however, calculated the 2015 uncollectible rate slightly differently than the Department. The OAG calculated the uncollectible rate as a percentage of total utility revenues, rather than as a percentage of tariffed revenues, and determined the uncollectible rate was 0.4466 percent for 2015.[442] Because MERC's uncollectible expense has been declining for years, the OAG asserts its 2015 level of approximately 0.45 percent of total revenues represents the most reasonable estimate of its current uncollectible expense.[443] In addition, the OAG noted that MERC expects that its new CIS system, the ICE system, will help reduce bad debt expense below 2015 actuals. Finally, according to the OAG, MERC's bad debt reserves are greater than needed and thus the Company has excess reserves in the event of a shortfall.[444]

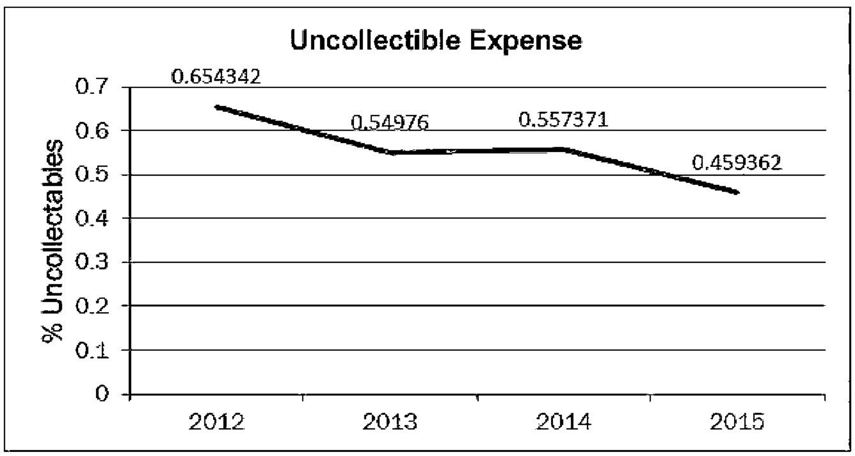
321. The OAG calculated that using its recommended uncollectible rate of 0.4466 percent would result in a $377,701 decrease of the uncollectible expense. However, the OAG clarified that its recommended uncollectible rate of 0.4466 percent should be applied to the final test year revenue ordered by the Commission.[445]

322. MERC disagreed with the Department's and the OAG's recommendation to use the 2015 uncollectible expense rate for purpose of calculating uncollectible expense. MERC recognized that its 2015 uncollectible expense as a percentage of revenues was lower as compared to the 2012-2014 average, but it disagreed with the Department's and OAG's contention that the 2015 percentage represents a downward trend that will continue. MERC maintained that recent years' uncollectible expense have fluctuated and that assuming a decline based on data of a single year is not appropriate.[446] MERC argued that use of a three-year historic average more fully accounts for the variability in the bad debt rates that has occurred in recent years.[447]

323. In response to the concerns expressed by the Department and the OAG, however, MERC proposed to update the three-year historical average to include the 2015 actual uncollectible expense. This resulted in a rate of 0.527586. MERC asserted that use of the 2013-2015 average would account for the lower uncollectible ratio experienced in 2015 while acknowledging the variations that have occurred in recent years.[448]

[441] Ex. 416 at 44 (St. Pierre Direct).
[442] Ex. 300 at 30-31 (Lebens Direct)
[443] Ex. 300 at 30 (Lebens Direct); Ex. 302 at 3-4 (Lebens Surrebuttal).
[444] Ex. 302 at 2-7 (Lebens Surrebuttal).
[445] Ex. 300 at 32 (Lebens Direct); Ex. 302 at 7 (Lebens Surrebuttal).
[446] Ex. 45 at 27-28 (DeMerritt Rebuttal).
[447] *Id.*; MERC Initial Br. at 44 (June 29, 2016) (eDocket No. 20166-122788-01).
[448] Ex. 45 at 28, SSD-R6 (DeMerritt Rebuttal).

324. The actual percentages of uncollectible expenses to tariffed revenues for the years 2012 to 2015 were as follows:[449]



325. The Department argued that although there was a small increase in the uncollectible expense in 2014, the historical percentages continue to follow a downward trend. The Department asserted that averaging, or "levelization," is only appropriate when there are significant upward and downward fluctuations. The Department maintained that use of a historical average is not reasonable in this instance because there is a clear downward trend in uncollectible cost.[450]

326. Neither the Department nor the OAG supported MERC's revised proposal to use a three-year historical rate from 2013-2015. Both the Department and the OAG maintained that the 2015 actual rate is a better measure of MERC's uncollectible rate for use in the 2016 test year.[451]

2. Analysis

327. In MERC's 2010 rate case, the Commission determined, that use of a historical average to calculate uncollectible expense was appropriate because there was wide variation in MERC's actual bad debt expense from 2008 to 2010.[452] However, in MERC's last rate case filed in 2013, the Commission determined that the consistent downward trend in MERC's bad debt expense between 2011 and 2013 indicated that the 2013 percentage would more accurately reflect actual costs for a 2014 test year.[453]

[449] Ex. 416 at 42 (St. Pierre Direct).
[450] Ex. 416 at 43 (St. Pierre Direct); Ex. 417 at 28 (St. Pierre Surrebuttal).
[451] Ex. 417 at 29 (St. Pierre Surrebuttal); Ex. 302 at 7 (Lebens Surrebuttal).
[452] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, MPUC Docket No. G-007/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 40 (July 13, 2012).
[453] 2013 MERC RATE CASE ORDER at 18.

328. The Commission explained in the 2013 rate case that it is not appropriate to use historic averages to set recovery for a cost that is trending downward:

> The Commission often employs averaging in ratemaking to smooth costs that vary from year to year. However, when the variation follows a clear trend, averaging can obscure the trend, resulting in inaccurate rates.
>
> Here, MERC's bad debt, as a percentage of revenue, has decreased consistently from 2011 to 2013. In light of this trend, the Commission concurs with the Department that MERC's 2013 bad-debt percentage provides the best predictor of MERC's bad debt going forward.[454]

329. In the 2013 rate case, the Commission ordered MERC to apply the 2013 bad debt percentage to the sum of the following figures, as determined in that rate case: (1) test year forecasted revenues at present rates, (2) the new base cost of gas, and (3) the approximate revenue deficiency, rounded down to the closest million to eliminate the circular reference.[455]

330. Like in MERC's 2013 rate case, the Administrative Law Judge recommends that the Commission use MERC's actual 2015 uncollectible expense ratio of 0.459362 percent, applied to the test year tariff revenues reduced by the updated cost of gas and approximate gross revenue deficiency determined by the Commission.[456]

331. Although there was a small increase in the uncollectible rate in 2014, the historical percentages continue to follow a downward trend. In fact, the actual 2015 rate was the lowest percentage since 2012, by about 0.19 percent.[457]

332. Therefore, despite the slight increase in 2014, the Administrative Law Judge finds that MERC's 2015 uncollectible expense rate as a percentage of tariffed revenues is the best predictor of MERC's bad debt going forward.

333. This conclusion is further supported by the testimony of MERC's witness, Mr. Kage, who discussed the benefits associated with MERC's recently upgraded CIS, the ICE system.[458] As noted by the OAG, Mr. Kage asserted that the ICE Project will improve the efficiency and effectiveness of MERC's billing and collection processes.[459] Given this testimony, MERC should experience additional reductions in its uncollectible expenses in the future.

334. Finally, the Administrative Law Judge notes that any doubt as to the reasonableness must be resolved in favor of the consumer.[460]

[454] 2013 MERC RATE CASE ORDER at 18.
[455] 2013 MERC RATE CASE ORDER at 18.
[456] *See id.;* Ex. 417 at 28-29, MAS-S-9 (St. Pierre Surrebuttal).
[457] Ex. 416 at 43 (St. Pierre Direct).
[458] Ex. 21 at 6-7 (Kage Direct).
[459] Ex. 21 at 6-7 (Kage Direct).
[460] Minn. Stat. § 216B.03.

VIII. Resolved Revenue Requirement Issues

A. ICE Issues

1. Deferred Development Costs

335. MERC proposed to recover $1,201,642 for deferred ICE Project development costs, amortized over two years.[461] The deferred amount reflects $881,642 in ICE Project development costs incurred through June 2015 and an additional deferral of $320,000 for forecasted costs for the months of July 2015 through October 2015.[462]

336. The deferred Ice Project development costs were a mixture of O&M costs and depreciation and ROA allocated from WBS.[463]

337. The Department agreed that MERC should be allowed to recover the $1,201,642 in deferred development costs.[464]

[461] Ex. 41 at 19-20, SSD-22 (DeMerritt Direct).
[462] Ex. 41 at 19-20, SSD-22 (DeMerritt Direct).
[463] Ex. 414 at 11 (Byrne Direct).
[464] Ex. 414 at 9, 16-17 (Byrne Direct).

338. The OAG initially disagreed with MERC's deferred ICE Project development cost proposal, arguing that MERC double-counted depreciation expenses related to the development costs.[465]

339. In response, MERC asserted that the 2014 and 2015 ICE Project development cost amounts represent depreciation expenses for 2014 and 2015 that were deferred before the 2016 test year. MERC maintained this deferral is consistent with the Commission's Order in Docket No. G011/GR-13-617.[466]

340. After the evidentiary hearing, the OAG informed MERC that it no longer challenges MERC's deferred development costs for the ICE Project.[467]

341. The Administrative Law Judge finds that MERC has demonstrated the deferred ICE Project development costs are reasonable, and MERC should be allowed to recover the amount of $1,201,642 in deferred costs, amortized as discussed below.

2. Amortization Period for Deferred ICE Development Costs

342. MERC proposed a two-year amortization period for deferred ICE development costs and requested that the amortization of these expenses begin with the implementation of final rates.[468]

343. The Department did not oppose a two-year amortization period for deferred ICE O&M development costs, but recommended a sunset provision to reduce rates after two years if MERC does not file a rate case.[469] With regard to the portion of deferred ICE development costs related to depreciation and ROA, the Department recommended that the deferred amount be amortized over the reasonable useful life of the assets.[470]

344. MERC agreed to amortize the deferred development O&M costs over a two-year period with a sunset provision to reduce rates after two years if MERC does not file a rate case. MERC also agreed to amortize the deferred depreciation expense and ROA over the useful life of the assets.[471]

345. MERC proposed an additional adjustment to the calculation. MERC recognized that, in the Department's proposal, a forecasted amount of $320,000 (July 2015-October 2015 expenses) was allocated between depreciation expense/ROA and O&M. MERC asserted that this allocation does not precisely match the actual depreciation expense/ROA and O&M breakdown, and that it is impossible to do so because actual expenses through October 2015 were $25,427 higher than forecast. MERC proposed that it may be more appropriate to use actuals through October 2015,

[465] Ex. 300 at 13-14 (Lebens Direct).
[466] Ex. 45 at 24-25 (DeMerritt Rebuttal).
[467] *See* OAG Response to Issues Matrix at 1 (June 29, 2016) (eDocket No. 20166-122793-01).
[468] Ex. 41 at 20 (DeMerritt Direct).
[469] Ex. 414 at 11, 17 (Byrne Direct).
[470] Ex. 414 at 12, 17 (Byrne Direct).
[471] Ex. 23 at 5-6 (Kage Rebuttal); Ex. 45 at 16 (DeMerritt Rebuttal).

and then apportion a reduction of the $25,427 across depreciation/ROA and O&M. This proposal would result in a reduction in amortization expense of $220,606.[472]

346. The Department agreed that this method of allocation is reasonable.[473]

347. No other party filed testimony on the issue.[474]

348. The Administrative Law Judge finds that the agreement between MERC and the Department as set forth in MERC's Rebuttal Testimony should be adopted in this proceeding.

3. Ongoing O&M Expenses and Useful Life of the ICE Assets

349. MERC also proposed recovery of $1,326,639 of labor and non-labor costs allocated to MERC for the ongoing maintenance and licensing costs of the ICE system, plus $2,655,245 of depreciation expense and ROA, for a total recovery of $3,981,884 billed as O&M expenses from WBS to MERC.[475]

350. The Department recommended that MERC adjust test year O&M expense for ICE depreciation and ROA of $2,655,245 ($884,096 ROA and $1,771,149 depreciation expense) to reflect a useful life of 15 years.[476] The Department also recommended that the ROA percentage used in the calculation of the ICE carrying charge from WBS be updated to reflect the Commission's final authorized ROE in this rate case.[477]

351. Initially, the OAG claimed ICE Project development cost amortization should be based on a seven-year useful life period.[478] However, the OAG later clarified that it takes no specific position on the length of the useful life for the ICE Project, but instead believes the useful life of the asset should be used as the denominator in the amortization calculation for both the overall ICE asset, including the implementation costs, and the deferred development costs.[479]

352. MERC agreed to the Department's proposal to adjust the test year O&M expense for ICE Project depreciation and ROA, and use a 15-year useful life for the core ICE CIS platform.[480] However, MERC did not agree with applying a 15-year life to the ICE interactive voice response system, the ICE web interface for customers, the ICE interactive system to be used by transportation customers and marketers, and the ICE data warehouse, all of which require updating more frequently as technology and security

[472] Ex. 45 at 16-17 (DeMerritt Rebuttal).
[473] Ex. 415 at 4-5 (Byrne Surrebuttal).
[474] OAG Response to Issues Matrix (June 29, 2016) (eDocket No. 20166-122793-01) (stating that the OAG "does not take a position on the amortization period.").
[475] Ex. 41 at 28-29 (DeMerritt Direct).
[476] Ex. 414 at 22 (Byrne Direct).
[477] Ex. 414 at 22 (Byrne Direct).
[478] Ex. 300 at 18-19 (Lebens Direct).
[479] Ex. 301 at 2 (Lebens Rebuttal).
[480] Ex. 45 at 22 (DeMerritt Rebuttal); Ex. 23 at 5-7 (Kage Rebuttal).

needs evolve.[481] MERC supported a 3-year life for non-core CIS components, including auxiliary software products that support the core CIS.[482] MERC also agreed with the Department's proposal to update the ROA for the ICE Project to reflect the Commission's final authorized return.[483]

353. The Department agreed to use a 15-year useful life for the core ICE CIS platform and a 3-year useful life for the auxiliary software products that support the core CIS.[484] As a result, both MERC and the Department agreed to an adjustment to the test year O&M expense for ICE depreciation and ROA of $2,655,245 ($884,096 ROA and $1,771,149 depreciation expense) to reflect a useful life of 15 years for the core ICE CIS platform and a three-year life for the auxiliary software products that support the core CIS.[485] The Department recommended that MERC provide the updated ROA calculation in a compliance filing within ten days of the Commission's deliberations in this rate case.[486] The financial effect of these agreed-upon recommendations decreases MERC's proposed O&M expense by $660,172.[487]

354. The Administrative Law Judge finds the parties' recommendations regarding ongoing O&M expense and the useful life of the ICE assets are reasonable and should be adopted.

B. MERC's Test Year Sales Forecast

355. MERC's proposed 2016 sales forecast was developed in MetrixND using an Ordinary Least Squares (OLS) methodology.[488] MetrixND is a statistical software package developed by Itron, a utility consulting firm.[489] The inputs to the OLS methodology included monthly binaries, time trend, Heating Degree Day, and economic and demographic variables, including lagged variables where necessary.[490] The forecasting models also incorporated various seasonal and autoregressive components where needed to correct for seasonality and serial correlation in the data patterns. The OLS forecast period was from 2015 through 2018, with 2016 being the test year for this proceeding.[491] The forecast was developed with monthly historical billed data from January 2007 through December 2014, and is based on forecasting done for each of MERC's three Purchase Gas Adjustment (PGA) systems by revenue class (i.e., Residential, Small Commercial and Industrial (SC&I), Large Commercial and Industrial (LC&I), Interruptible, Joint, and Transport).[492]

[481] Ex. 45 at 22 (DeMerritt Rebuttal); Ex. 23 at 5-7 (Kage Rebuttal).
[482] Ex. 45 at 22 (DeMerritt Rebuttal).
[483] Ex. 45 at 22-24 (DeMerritt Rebuttal).
[484] Ex. 415 at 13 (Byrne Surrebuttal).
[485] Ex. 415 at 13 (Byrne Surrebuttal).
[486] Ex. 415 at 13 (Byrne Surrebuttal).
[487] Ex. 415 at 13 (Byrne Surrebuttal).
[488] Ex. 27 at 7 (John Direct).
[489] Ex. 27 at 7 (John Direct).
[490] Ex. 27 at 7 (John Direct).
[491] Ex. 27 at 7 (John Direct).
[492] Ex. 27 at 7 (John Direct).

356. The Department did not recommend any adjustment to MERC's proposed 2016 sales forecast because it concluded the results of MERC's sales forecasts did not appear to be biased.[493] The Department, however, raised concerns about MERC's energy sales and customer counts for various rate classes to set the stage for MERC to work with the Department on the sales forecast between now and MERC's next rate case.[494]

357. MERC agreed with the Department's recommendation to use MERC's proposed level of sales as filed in this proceeding and agreed to confirm that, in future forecast pre-filings, all relevant data files will be provided to the Department.[495]

358. MERC and the Department agreed that issues raised regarding MERC's forecasting methodology could reasonably be worked out before MERC's next rate case. MERC is committed to working with the Department to address the Department's comments and to develop a sales forecast that is reasonable and acceptable and to provide the appropriate information to the Department in MERC's next rate case filing.[496]

359. No other party offered any testimony regarding MERC's 2016 sales forecast.

360. The Administrative Law Judge concludes that MERC's sales forecast is a reasonable estimate of the proposed test year sales and should be used for purposes of setting rates in this proceeding.

C. Chatfield and Caledonia Property Acquisitions/Renovations

361. In prior decisions, the Commission ordered that costs related to MERC's acquisition of the Chatfield and Caledonia buildings be subject to review for prudence in MERC's next rate case.[497]

362. In this proceeding, MERC submitted Direct Testimony and schedules to support the prudency and reasonableness of actual costs related to the Chatfield and Caledonia properties.[498] The total project cost spent through July 2015 for the Chatfield building was $330,941, and for the Caledonia building was $213,559.[499] The 2016 proposed depreciation expense included in the test year for Chatfield totaled $6,419 and

[493] Ex. 400 at 19 (Shah Direct); Ex. 401 at 8 (Shah Surrebuttal).
[494] Ex. 400 at 10-18 (Shah Direct).
[495] Ex. 28 at 4-6 (Clabots Direct).
[496] Ex. 28 at 4-7 (Clabots Direct).
[497] *In the Matter of the Petition of Minn. Energy Res. Corp. (MERC) for Approval of Property Acquisition*, MPUC Docket No. G-007,011/PA-13-201, ORDER APPROVING MERC'S PETITION (May 20, 2013); *In the Matter of the Petition of Minn. Energy Res. Corp. (MERC) for Approval of Caledonia, Minn. Property Acquisition*, MPUC Docket No. G011/PA-14-437, ORDER APPROVING MERC'S PETITION (Oct. 13, 2014).
[498] Ex. 41, SSD-28 (DeMerritt Direct).
[499] Ex. 41 at 12 (DeMerritt Direct).

for Caledonia totaled $2,785. The 2016 proposed accumulated depreciation included in the test year for Chatfield was $22,230 and for Caledonia was $6,151.[500]

363. MERC experienced slightly higher capital costs (approximately $41,000, or 14.1 percent) than originally forecasted to purchase and remodel the Chatfield building.[501] Plus, MERC incurred an additional $8,714 in closing costs.[502] MERC's acquisition of the property results in more efficient operations by providing space to accommodate employees, deliveries, and storage necessary to support MERC's provision of natural gas services in southeastern Minnesota.[503]

364. The total cost to purchase the Caledonia property was $213,000, including fees. MERC has begun the bidding process for renovations.[504] MERC will provide an update on total anticipated costs as the project progresses.[505]

365. The Administrative Law Judge finds the costs associated with the Chatfield and Caledonia property acquisitions and renovations thus far are prudent and reasonable.

D. Rochester Project

366. MERC is the sole provider of natural gas services to Rochester and surrounding local communities.[506] MERC's supplier of natural gas, Northern Natural Gas (NNG), is the sole wholesale provider of natural gas in the Rochester area.[507] According to MERC, the growth in demand in the area over the last several years has shown that both MERC's and NNG's existing infrastructure are inadequate to meet the increased demand for gas service that is forecasted to continue to grow over the next ten years. The increased demand is driven in part by the Destination Medical Center development plan for the city of Rochester.[508] To address increased demand, MERC proposes to upgrade its existing natural gas distribution system in the city of Rochester in two phases (the Rochester Project).[509]

367. Phase I of the Rochester Project involves modernizing, standardizing, and interconnecting portions of MERC's distribution regulator stations and piping within the City of Rochester.[510] According to MERC, Phase II involves upgrading MERC's town border station system within the city. Together, the Phase I and II upgrades will allow

[500] Ex. 41 at 12-15, SSD-28 (DeMerritt Direct).
[501] Ex. 41 at 13 (DeMeritt Direct).
[502] Ex. 41 at 14 (DeMerritt Direct).
[503] Ex. 41 at 14 (DeMerritt Direct).
[504] Ex. 41 at 15 (DeMerritt Direct).
[505] Ex. 41 at 15 (DeMerritt Direct).
[506] Ex. 13 at 14 (Kult Direct).
[507] Ex. 13 at 14 (Kult Direct).
[508] Ex. 13 at 14 (Kult Direct).
[509] Ex. 13 at 14 (Kult Direct).
[510] Ex. 13 at 14 (Kult Direct).

MERC to adequately maintain gas supply and balance across its Rochester distribution system as customer demand grows.[511]

368. MERC projected $5.6 million in 2015 capital costs in the Phase I upgrade of its distribution system in the City of Rochester.[512] Approximately $640,000 of the Phase II capital costs will be incurred during the 2016 test year and MERC requested recovery of those costs in this rate case.[513] MERC proposed to recover the approximately $43.4 million balance of the Phase II capital costs for 2017 and beyond through a Natural Gas Extension Project (NGEP) rider and subsequent rate cases.[514]

369. MERC filed for rider recovery on October 26, 2015, and proposed to implement the rider on January 1, 2017.[515] On February 8, 2016, the Commission issued a Notice of and Order for Hearing in Docket No. G011/M-15-895, ordering that all Rochester Project Phase II costs be removed from this rate case.[516]

370. The Department recommended that, consistent with the Commission's requirement to remove Phase II expenditures from the 2016 test year, the Commission allow MERC to defer the Phase II expenditures incurred after January 1, 2016, until a decision is made on the prudence of Phase II.[517] The Department noted that if the NGEP rider is approved, the deferred Phase II expenditures would be included in the NGEP rider.[518] The Department also recommended a reduction in the rate base by $102,300 of Distribution Plant, $622 of Accumulated Reserve for Depreciation – Distribution, $188,300 of Construction Work in Progress, $1,604 of Accumulated Reserve on Plant – Distribution, and removal of $2,056 of Depreciation Expense from the income statement to reflect the removal of Phase II costs.[519]

371. MERC agreed with the Department's recommendations, provided a return on the deferral is granted.[520]

372. The Department stated that it could support the allowance of a return on the authorized rate of return on the forecasted net rate base amount because that is what MERC would be allowed if the costs were included in the test year.[521]

[511] Ex. 13 at 14-15 (Kult Direct).
[512] Ex. 13 at 15 (Kult Direct).
[513] Ex. 13 at 15 (Kult Direct).
[514] Ex. 13 at 15 (Kult Direct).
[515] *In the Matter of the Petition of Minn. Energy Res. Corp. for Evaluation and Approval of Rider Recovery for its Rochester Nat. Gas Extension Project*, MPUC Docket No. G011/GP-15-895, INITIAL FILING – ROCHESTER PROJECT RIDER PETITION (Oct. 26, 2015).
[516] *In the Matter of a Petition by Minn. Energy Res. Corp. for Evaluation and Approval of Rider Recovery for Its Rochester Nat. Gas Extension Project*, MPUC Docket No. G011/GP-15-895, NOTICE OF AND ORDER FOR HEARING (Feb. 8, 2016).
[517] Ex. 416 at 22-23 (St. Pierre Direct).
[518] Ex. 416 at 23 (St. Pierre Direct).
[519] Ex. 416 at 23 (St. Pierre Direct).
[520] Ex. 45 at 14 (DeMerritt Direct).
[521] Ex. 417 at 13 (St. Pierre Surrebuttal).

373. The Administrative Law Judge finds that the treatment of the Rochester Project costs as agreed upon by MERC and the Department is reasonable and appropriate.

E. Current Return on Construction Work in Progress

374. Construction Work in Progress (CWIP) and Allowance for Funds Used During Construction (AFUDC) are accounting mechanisms used to permit utilities to recover the financing costs of capital projects while the projects are under construction. Capital costs incurred during construction are placed in rate base as CWIP and the associated financing costs are added to net income as AFUDC, normally offsetting the return on CWIP until the plant under construction goes into service.[522]

375. Minn. Stat. § 216B.16, subd. 6a, authorizes the Commission to consider CWIP in ratemaking. The statute provides:

> To the extent that construction work in progress is included in the rate base, the commission shall determine in its discretion whether and to what extent the income used in determining the actual return on the public utility property shall include an allowance for funds used during construction, considering the following factors:
>
> (1) the magnitude of the construction work in progress as a percentage of the net investment rate base;
>
> (2) the impact on cash flow and the utility's capital costs;
>
> (3) the effect on consumer rates;
>
> (4) whether it confers a present benefit upon an identifiable class or classes of customers; and
>
> (5) whether it is of a short-term nature or will be imminently useful in the provision of utility service.

376. MERC proposed to include CWIP in rate base with a current return on the assets.[523] MERC provided several reasons for its proposal.[524]

377. First, MERC is projecting a significant increase in capital expenditures as compared to historical averages.[525] Because of the increase in capital expenditures, the average 13-month balance of CWIP as compared to total rate base is proposed to be a

[522] Ex. 416 at 11 (St. Pierre Direct).
[523] Ex. 41 at 9 (DeMerritt Direct).
[524] Ex. 41 at 9-10 (DeMerritt Direct).
[525] Ex. 41 at 9-10 (DeMerritt Direct).

significant portion in 2016.[526] The seven-year average for 2008-2014 of CWIP to rate base was 0.99 percent, but due to the increase in capital expenditures, the 2016 CWIP to rate base proposed is 5.30 percent.[527] This translates to a revenue requirement amount of $1,722,395, or 1.50 percent of MERC's total revenue requirement.[528]

378. Second, MERC projected cash expenditures of $107,605,310 from July 2014 through December 2016.[529] Associated with this capital spending is a 47 percent, or $41 million, increase in long-term debt as compared to the June 2014 long-term debt balance of $87 million.[530] MERC's common equity needs also increased 40 percent, or $39.2 million, from June 2014 to December 2016.[531] In total, MERC's cash needs (common equity, long-term debt, and short-term debt) increased 36 percent, or $72.6 million, from June 2014 to December 2016.[532]

379. Third, of the projected cash expenditures of $107,605,310, MERC requested inclusion of $13,238,070, or 12 percent, in rate base to earn a current return as CWIP.[533] This amount translates to a revenue requirement of $1,722,395.[534]

380. Fourth, MERC's test year capital projects are not customer class specific and benefit all of MERC's customer classes.[535]

381. Fifth, MERC's projects are typically short term in nature, as 88 percent of the capital expenditures are placed in service before the end of the test year.[536] Even MERC's largest project, the Rochester expansion project, is not projected to be in CWIP for a period of greater than 36 months because it will be placed in service in regular intervals.[537]

382. MERC stated that the CWIP balances it requested for rate base recovery are prudent because the amounts are related to pipeline upgrades, replacements, and expansion projects, as well as building upgrades, vehicle replacements, and gate station upgrades, all of which pertain to maintaining and constructing a safe and reliable system for MERC's customers.[538]

383. MERC did not propose an AFUDC offset to CWIP included in rate base because it is a relatively small utility with a sizeable increase in capital expenditures for

[526] Ex. 41 at 10 (DeMerritt Direct).
[527] Ex. 41 at 10 (DeMerritt Direct).
[528] Ex. 41 at 10 (DeMerritt Direct).
[529] Ex. 41 at 10 (DeMerritt Direct);
[530] Ex. 41 at 10 (DeMerritt Direct);
[531] Ex. 41 at 10 (DeMerritt Direct);
[532] Ex. 41 at 10 (DeMerritt Direct); Ex. 15, LJG-1 (Gast Direct).
[533] Ex. 41 at 10 (DeMerritt Direct).
[534] Ex. 41 at 10 (DeMerritt Direct).
[535] Ex. 41 at 10-11, SSD-19 (DeMerritt Direct).
[536] Ex. 41 at 11 (DeMerritt Direct).
[537] Ex. 41 at 11 (DeMerritt Direct).
[538] Ex. 41 at 11-12 (DeMerritt Direct).

the next several years.[539] Instead, MERC proposed a current return on CWIP for a minority of pending projects in order to mitigate risk and support cash flows.[540]

384. Consistent with past Commission decisions, the Department concluded that it is reasonable for MERC to include CWIP in rate base as long as there is an AFUDC offset.[541] Based on the proposed CWIP, the Department proposed an AFUDC offset of $1,019,025.[542] If the Commission were to remove from the test year any costs from CWIP, then the AFUDC offset should be decreased accordingly.[543] Further, if the Commission were to reduce rate base for projects not in service, then CWIP may increase.[544] The Department further recommended that the Commission require MERC to update the return used in the calculation of AFUDC to the approved rate of return in the current rate case, and that this update be filed in MERC's final rates compliance filing in this proceeding.[545]

385. MERC did not agree that an AFUDC offset was warranted.[546] MERC, however, proposed that if its recommendation to include CWIP in rate base without an AFUDC offset is not accepted, then, at a minimum, those projects with a duration of less than 30 days or costing less than $25,000 should be included in rate base with a current return, leaving the remaining CWIP in rate base with an AFUDC offset.[547]

386. The Department agreed with MERC's alternative proposal that short-term projects and projects costing less than $25,000 be included in rate base with a current return, with the remaining projects in CWIP having an AFUDC offset. The Department noted that this approach is reasonable and consistent with the approach that the Commission adopted in Xcel's 2013 rate case.[548]

387. The Department noted that MERC provided an IR response showing that, with this proposal, there would be no CWIP amount remaining in the test year, and no AFUDC offset.[549] The Department's witness, Ms. St. Pierre, calculated that the effect of the Department's recommendation would increase Net Utility Plant by $13,049,770 and decrease CWIP in rate base by $13,049,770 (net zero).[550]

388. MERC agreed with the Department's adjustment moving CWIP balances into Net Utility Plant.[551]

[539] Ex. 41 at 12 (DeMerritt Direct).
[540] Ex. 41 at 12 (DeMerritt Direct).
[541] Ex. 416 at 15-16 (St. Pierre Direct).
[542] Ex. 416 at 16 (St. Pierre Direct).
[543] Ex. 416 at 16-17 (St. Pierre Direct).
[544] Ex. 416 at 17 (St. Pierre Direct).
[545] Ex. 416 at 17 (St. Pierre Direct).
[546] Ex. 45 at 8 (DeMerritt Rebuttal).
[547] Ex. 45 at 9-10 (DeMerritt Rebuttal).
[548] Ex. 417 at 10 (St. Pierre Surrebuttal).
[549] Ex. 417 at 9-10 (St. Pierre Surrebuttal).
[550] Ex. 417 at 10-11 (St. Pierre Surrebuttal).
[551] Tr. Vol. 1 at 128 (S. DeMerritt).

389. No other party offered any testimony regarding MERC's CWIP.

390. The Administrative Law Judge finds the agreement reached between MERC and the Department with respect to CWIP and AFUDC is reasonable.

F. Actual Deferred Tax Balances

391. The federal Protecting Americans from Tax Hikes (PATH) Act of 2015, signed into law in late December 2015, extended Bonus Depreciation through 2019.[552]

392. The extension of bonus depreciation resulted in an increase in MERC's deferred tax liability balances as compared to the originally filed 2016 test year amounts, thus reducing rate base.[553] The bonus depreciation increased MERC's accumulated deferred income tax liability in rate base by $3,220,893.[554] Bonus depreciation at the WBS level decreased MERC's allocated share of WBS's expense by $59,405.[555]

393. The Department recommended reducing rate base by $3,220,893 to capture the financial effect of the extension of bonus depreciation included in the federal PATH Act of 2015.[556] The Department also recommended a decrease in Administrative and General (A&G) expense in the test year income statement by $59,405 for MERC's allocated share of WBS expenses related to bonus depreciation.[557]

394. MERC agreed with the Department's adjustments.[558]

395. No other party offered testimony regarding the extension of bonus depreciation.

396. The Administrative Law Judge finds that a reduction in MERC's rate base by $3,220,893 and a decrease in A&G expense in the test year income statement by $59,405 for actual deferred tax balances are both appropriate.

G. Cash Working Capital

397. MERC performs a Lead/Lag Study to determine the cash working capital (CWC) component of working capital.[559] The study measured the differences in time frames between (1) the time that service is rendered until the revenues for that service are received (lead) and (2) the time that labor, materials, or services are used in providing the service until expenditures for the items are made (lag).[560]

[552] Ex. 416 at 17, MAS-12 at 2 (St. Pierre Direct).
[553] Ex. 416, MAS-12 at 2 (St. Pierre Direct).
[554] Ex 416 at 18 (St. Pierre Direct).
[555] Ex. 416, MAS-12 at 2 (St. Pierre Direct).
[556] Ex. 416 at 18 (St. Pierre Direct).
[557] Ex. 416 at 18 (St. Pierre Direct).
[558] Ex. 45 at 15 (DeMerritt Rebuttal).
[559] Ex. 41 at 46, SSD-18 at 1 (DeMerritt Direct).
[560] Ex. 41 at 46 (DeMerritt Direct).