FILED
March 9, 2022
Data Center
Missouri Public
Service Commission

Exhibit No. 122

Staff – Exhibit 122
Mark Oligschlaeger
Rebuttal Testimony
File No. ER-2021-0312

Exhibit No.:	
Issues:	*Asbury Unrecovered Investment*
Witness:	*Mark L. Oligschlaeger*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Rebuttal Testimony*
Case No.:	*ER-2021-0312*
Date Testimony Prepared:	*December 20, 2021*

MISSOURI PUBLIC SERVICE COMMISSION

FINANCIAL AND BUSINESS ANALYSIS DIVISION

REBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

THE EMPIRE DISTRICT ELECTRIC COMPANY,
d/b/a Liberty

CASE NO. ER-2021-0312

Jefferson City, Missouri
December 2021

REBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

THE EMPIRE DISTRICT ELECTRIC COMPANY,
d/b/a Liberty

CASE NO. ER-2021-0312

Q. Please state your name and business address.

A. Mark L. Oligschlaeger, P.O. Box 360, Suite 440, Jefferson City, MO 65102.

Q. Have you previously contributed to Staff's Cost of Service Revenue Requirement Report ("COS Report") filing in this case dated October 29, 2021?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this testimony is to respond to the direct testimony filed in this case by The Empire District Electric Company, d/b/a Liberty ("Empire," "EDE" or "Company") witness Frank C. Graves regarding the issue of ongoing rate treatment of unrecovered capital costs associated with the retired Asbury Generating Unit ("Asbury").

<u>ASBURY UNRECOVERED INVESTMENT</u>

Q. Before responding to specific points within Mr. Graves' direct testimony, please summarize Staff's recommended treatment of the unrecovered balance of Asbury in this proceeding.

A. Staff recommends a sharing of the responsibility for the unrecovered capital costs of the Asbury unit as of its retirement date in rates between Empire's shareholders and customers. This would be accomplished by inclusion in rates of an amortization of the unrecovered balance, but exclusion of the unamortized balance from EDE's rate base. This position is addressed in more detail in the section *Asbury Generating Station Unrecovered Investment* found in Staff's COS Report in this case at pages 134 - 138.

Q. At page 41 of his direct testimony, EDE witness Graves states that "longstanding and economically well-justified principles and standards in the utility industry strongly indicate that all prudently undertaken investments should be fully recoverable from customers, even if the underlying assets should at some point prove less economic than was originally intended." Do you agree with this?

A. Only in part. If money is prudently invested in assets that turn out through unforeseen factors to be less economic than assumed, then continued recovery of the asset costs should generally be allowed at least as long as the asset remains in service. However, under normal ratemaking the costs associated with assets that have been retired should no longer be recovered in rates.

Q. Why shouldn't utilities generally expect to continue to recover costs associated with assets after they are retired?

A. To state the obvious, that is because retired assets are no longer used and useful, or providing a current benefit to customers. Whether the initial investment in the retired assets by the utility was prudent or not is in most cases irrelevant to this general policy.

There can be unique situations in which it is reasonable that customers should contribute towards cost recovery of assets following their retirement. Staff's position is that the Asbury retirement is one of those rare instances.

Q. At pages 43 – 44 of his direct testimony, Mr. Graves states an apparent belief that, under proper operation of utility regulation, customers should bear all of the risk of prudent assets becoming uneconomic, even after the assets are retired. Do you agree with this contention?

A. No. Mr. Graves seems to be arguing that, because the operation of utility regulation tends to limit the amount of gain/profit utilities can retain over time, fairness requires that utilities in turn be shielded from financial losses such as those associated with retired plant assets. However, I regard this line of thinking to be one-sided. One benefit of rate regulation from a utility perspective is that, while the utility foregoes the possibility of making very high profits over time, the utility also will not be subject to extreme financial losses. For example, it is practically unheard of for a utility company to go bankrupt and cease operating in the United States. Under the normal regulatory paradigm in the U.S., I agree that utility companies should not expect either to be able to retain financial gains to the same degree as unregulated businesses, or be exposed to financial loss to the same degree as unregulated companies. However, a balanced risk/reward relationship for utilities through operation of rate regulation does not require that the companies be completely shielded from any and all losses associated with unforeseen events, such as those that led to the decision to retire Asbury.

Q. Can you describe another situation in which utilities are generally assigned a portion of a loss for ratemaking purposes resulting from unforeseen events?

A. Yes. There are instances in which utilities are subject to unforeseen natural disasters, such as tornadoes, other severe wind storms, ice storms, floods, etc. These events can result in serious damage to utility infrastructure and consequent loss of service to customers. No allowance is provided in utility ratemaking for such extraordinary events, but nonetheless it is expected that the utilities undertake the necessary measures and incur costs to repair their systems and restore service to customers as quickly as possible.

Notwithstanding the importance of these expenditures to the public, the Commission's general policy has not been to provide utilities with full, after-the-fact recovery of these extraordinary costs in rates. Instead, in most cases the Commission has effected a "sharing" of these costs between shareholders and ratepayers by allowing the utilities to recover the repair/restoration costs through a multi-year amortization, but not allowing a return on the unamortized balance in rate base. This approach does not assign the full risk of unanticipated natural disasters to fall solely on customers, but also assigns a portion of this risk to utility shareholders. Staff's position in this case is also a reasonable approach to assigning the risk between ratepayers and shareholders of the unanticipated economic, regulatory and political changes that led to the Asbury retirement.

Q. At page 49, line 22 through page 50, line 1 Empire witness Mr. Graves describes the consequences of failing to provide its requested rate treatment of unrecovered Asbury investment as constituting a "penalty" to EDE, and a "windfall" for customers. Do you agree with these characterizations?

A. No. A proposal to share the rate responsibility between shareholders and customers for retired plant assets does not provide customers a "windfall" from any reasonable perspective, when taking into account both the undeniable fact that Asbury is not providing a current benefit to them and the new costs of replacement renewable generation ratepayers are being asked to bear by the Company. To ask customers to pay for full rate recovery of both new generating resources and the retired resources the wind farms are replacing strikes me as much more imposing an unwarranted "penalty" on customers than somehow providing them a "windfall."

Q. At page 48 of his direct, Mr. Graves discusses the savings expected to accrue to customers from Empire's replacement of Asbury with wind generation. Please comment.

A. Empire has indeed presented analyses in prior cases that purported to support its contention that over the long-term customers will see overall savings in rates due to its decisions to retire Asbury and add new renewable generation. However, the existence of these savings are only projections at this point, and the bulk of the purported customer savings are assumed to only materialize many years in the future. Accordingly, Staff perceives that there is an undeniable risk that Empire's customers may ultimately not accrue overall savings in rates due to the Asbury retirement and windfarm addition decisions.

Q. Do the prior regulatory agreements reached by Empire, Staff, and other parties in prior proceedings regarding the Company's new wind farms reflect any measures to mitigate potential customer harm from Empire's recent generation decisions?

A. Yes. In Case No. EA-2019-0010, the Commission approved a stipulation and agreement submitted by certain parties to that proceeding that called for establishment of a "market price protection mechanism" (MPPM) to mitigate the financial consequences to Empire ratepayers if the new windfarms prove to be uneconomic in the long-term. The MPPM would not be necessary if the purported customer savings associated with the new windfarms was anywhere close to being guaranteed.

Q. At page 44 of his direct testimony, Mr. Graves opines that "disallowing full recovery of retired out-of-the-money assets that were prudently chosen and approved sends the wrong signals to and creates perverse incentives for resource planners and investors." Do you agree?

A. No. Regulatory "incentives" and "signals" to utilities are only appropriate in so far as they support a reasonable end result for both the utility and its customers. It is simply improper on its face for Empire to collect from customers a return on and of both the retired Asbury generating unit and the new wind farms added to its system by the Company. A much more appropriate and balanced allocation of the risk associated with the Asbury unit becoming uneconomic over time is to share that cost responsibility between Empire's shareholders and ratepayers. Granting a utility the most favorable rate treatment possible in order to "incent" a particular desired regulatory outcome is neither necessary nor appropriate in this circumstance.

Q. Would Empire have chosen to retire the Asbury plant when it did if it knew it would not receive full recovery of and on that investment in later rate proceedings?

A. I do not know. However, even without knowledge of the applicable future ratemaking, Empire willingly chose to take on the risk of less than full recovery of Asbury in the future when the Company retired those assets in early 2020.

Q. Should utilities have to be "incented" in order to make prudent decisions?

A. No, the obligation of the utility to provide safe and adequate service to customers at a just and reasonable rate is binding regardless of the financial consequences to the utility of meeting that obligation. In short, if retiring Asbury was the prudent and most economical action Empire could take in early 2020, it was obligated to do so regardless of whether it ultimately received full, partial or no rate treatment of the unrecovered plant balance in the future.

Q. At pages 44 – 48 of his direct testimony, Mr. Graves generally addresses the topic of whether the return on equity (ROE) allowance granted to Empire in past rate cases served to compensate investors for any subsequent disallowance of Asbury costs following its retirement. Is Staff's rationale for its position on unrecovered Asbury costs in this case premised upon any particular belief as to whether the risk of early generating unit retirements was factored into the ROE levels authorized for Empire in past rate cases?

A. No. I cannot state with certainty what investor expectations might have been regarding post-retirement rate treatment of Asbury costs prior to the unit's retirement. I will say that Empire investors were certainly aware of or should have been aware of the impending retirement of Asbury prior to the most recent Empire general rate case, No. ER-2019-0374, and likewise should have been aware that no predeterminations of any sort had been communicated by the Commission regarding the ultimate rate treatment of Asbury unrecovered investment following its retirement.

Q. Please describe Appendix A attached to Mr. Graves' direct testimony.

A. Mr. Graves' Appendix A contains a listing of regulatory proceedings, in other jurisdictions across the U.S. since 2009, that Mr. Graves alleges provide support for Empire's position regarding rate recovery of both a return of and on its unrecovered investment in the Asbury unit. There are a total of 32 cases listed in Appendix A.

Q. Did Staff attempt to review these cases to verify whether Empire witness Mr. Graves' interpretation of them was accurate?

A. Yes. Staff conducted an internet search of the applicable public utility commission websites to obtain additional information regarding the regulatory proceedings listed in Mr. Graves Appendix A. For almost all of the cases found in Appendix A, Staff was able to find key documents, usually Public Utility Commissions (PUC) orders or stipulations, in order to attempt to determine the general nature of the regulatory treatments ordered in relation to coal unit retirements.

Q, Does Staff's research show that Mr. Graves is correct in asserting that the various actions taken by the PUCs depicted in Appendix A support Empire's position of obtaining a "full recovery" of the remaining Asbury costs?

A. No, for the most part it does not. Based upon Staff's research, there appears to be only a handful of cases listed in Appendix A in which the PUC in question appears to have authorized full recovery of retired coal unit costs in an equivalent manner to what Empire is seeking from the Commission in this case (i.e., recovery of the unrecovered Asbury balance through a multi-year amortization, with rate base treatment of the unamortized balance).

Q. How would you broadly characterize the nature of the applicable issues in the regulatory proceedings listed in Mr. Graves Appendix A?

A. The cases mainly appear to fall under four categories:

1) Orders providing certain regulatory/accounting treatments to the utility prior to the coal unit's retirement date;

2) Orders allowing the utility to include in rates an amortization of the unrecovered cost of the coal unit after its retirement, but which do not clearly address the question of rate base treatment of the unamortized balance;

3) Orders authorizing the utility to apply certain accounting treatments to coal retirement costs, but that reserve any ratemaking determinations regarding the costs to later regulatory proceedings; and

4) Orders allowing the utility special accounting treatment in order to prepare for potential securitization of the unrecovered coal unit costs.

None of the cases falling into these four categories support Empire's request for a full recovery of and on the Asbury investment in this case. I will address the reasons for this below.

Q. Why wouldn't requests for regulatory/accounting treatments prior to coal unit retirements support Empire's requested Asbury ratemaking in this case?

A. These situations, typically involving requests for accelerated depreciation rates to match the new planned retirement dates for the coal units, involve units still in service at the time and still eligible for normal cost recovery of depreciation and other plant-related costs in rates. Requests for ratemaking treatment of costs associated with retired plant assets are of a fundamentally different nature, and would need to be assessed using very different criteria.

Q. What are some examples of cases cited by Mr. Graves that fall into this category?

A. The 2009 Public Service Company of Colorado case (Colorado PUC) and the 2011 Portland General Electric Company Case (Oregon PUC) are examples of this category of regulatory proceeding. Both of these cases are listed on page 57 of Mr. Graves' direct testimony.

Q. Why wouldn't PUC authorizations to book or recover in rates amortizations of unrecovered costs for coal units following retirement support Empire's requested ratemaking for Asbury in this case?

A. Some of the cases included in Mr. Graves' Appendix A indicate that the PUC approved amortizations of unrecovered coal unit costs following retirement. To the extent those PUC orders authorizing amortization of unrecovered costs were intended to set ratemaking treatments, these orders would appear to be generally consistent with the Staff's recommendation to allow Empire to recover in rates an amortization of its unrecovered Asbury investment costs over a 15-year period. However, with rare exception, the PUCs in question that ordered rate amortizations did not appear to address whether the unamortized amounts of coal investment should also be included in utility rate base, and thereby earn a return. Empire, of course, is requesting such rate base treatment in this case from the Missouri Commission.

Q. Is it possible that authorization by PUCs of rate inclusion of unrecovered coal unit investment through amortizations automatically or inherently involves inclusion in rate base of the unamortized balance?

A. Not in my opinion, as the decisions to allow a return of and a return on costs are entirely separate and distinct ratemaking determinations. I can state with certainty that, in Missouri, there have been many cases in which the Commission has ordered certain utility costs to be amortized in rates over a multi-year period without allowing rate base treatment for the costs to be amortized.

Q. What are examples of cases cited by Mr. Graves that would fall into this category?

A. The 2012 Georgia Power Company case (Georgia PUC) and the 2014 Wisconsin Public Service Corporation case (Wisconsin PUC) are examples of this category of regulatory proceeding. Both cases are listed on page 57 of Mr. Graves' direct testimony.

Q. Why wouldn't PUC authorizations for accounting treatment of unrecovered coal costs support Empire's requested Asbury ratemaking in this case?

A. Empire is asking the Missouri Commission to authorize inclusion in rates of unrecovered Asbury costs. Orders from other PUCs that deal exclusively with accounting treatment of such costs, but reserve consideration of the costs for ratemaking purposes at a later time, is not a precedent for the rate treatment Empire is seeking in Missouri for Asbury unrecovered costs.

Q. What are examples of cases cited by Mr. Graves that would fall into this category?

A. The 2014 Black Hills Power case (South Dakota PUC) and the 2016 Gulf Power Company case (Florida PUC) are examples of this category of regulatory proceeding. Citations to these cases can be found at pages 57 and 58 of Mr. Graves' direct testimony, respectively.

Q. Why wouldn't PUC authorization of regulatory treatment to allow for potential securitization of unrecovered coal unit investment support Empire's requested Asbury ratemaking in this case?

A. Securitization is a unique rate treatment that allows for recovery from customers of certain large dollar costs by utilities through a special type of bond issuance. Empire is not seeking to securitize its unrecovered Asbury costs, though. As such, the actions of other PUCs in regard to potential securitization of coal unit investment is irrelevant to the issues currently before the Missouri Commission in this proceeding. It should be noted that under Missouri's securitization statute, Section 393.1700.2(3)(c)b, a prerequisite to securitization is a finding by the Commission that the "issuance of securitized utility tariff bonds and the imposition and collection of a securitized utility tariff charge are just and reasonable and in the public interest and are expected to provide quantifiable net present value benefits to customers as compared to recovery of the components of securitized utility tariff costs that would have been incurred absent the issuance of securitized utility tariff bonds."

Q. What are some examples of cases cited by Mr. Graves involving securitization that fall into this category?

A. The 2018 Consumers Energy case (Michigan PUC) and the 2020 Public Service Company of New Mexico case (New Mexico PUC) are examples of this type of regulatory proceeding. These cases are listed at pages 58 and 60 of Mr. Graves' direct testimony, respectively.

Q. What is Schedule MLO-1 attached to this testimony?

A. Schedule MO-1 is the applicable pages from documents found by Staff on PUC websites for each of the cases I have specifically cited above from Mr. Graves' Appendix A. All of these cases serve as examples to support my characterization of the treatments granted by those PUCs to costs associated with potential or actual early coal unit retirements in those jurisdictions.

Q. Did Mr. Graves include any Missouri Commission cases in his Appendix A?

A. Yes. Mr. Graves included Case No. EC-2019-0200 in his testimony attachment, apparently upon the belief that this case provides some sort of precedent for Empire's requested Asbury ratemaking in this case.

Q. Are you familiar with that particular proceeding?

A. Yes. I was the Staff witness in that case.

Q. Please generally describe the subject matter of that case.

A. The complaint case was filed by The Office of the Public Counsel ("OPC") and the Midwest Energy Consumers Group (MECG) against KCPL Greater Missouri Operations Company (now Evergy Missouri West, or "Evergy West") shortly after Evergy West made a decision to retire its coal-fired Sibley Energy Station ("Sibley") in late 2018. The retirement decision was announced at the very end of the processing of Evergy West's general rate case, No. ER-2018-0146, and the rates ordered by the Commission as a result of that rate case included allowances for Evergy West's return of and on its investment in Sibley, as well as operation & maintenance expenses and other costs incurred due to operation of that facility.

The filing made by OPC and MECG sought authorization from the Commission to require Evergy West to defer all of the Sibley costs included in rates that would no longer be incurred after the retirement (including the return on the assets), so that such amounts could potentially be returned to customers in Evergy West's next general rate case. The Commission ultimately decided to grant OPC's and MECG's requests for a Sibley deferral.

This proceeding concerned only a dispute regarding appropriate accounting for the Sibley related costs between the time of the unit's retirement and Evergy West's next rate case. It did not concern any determinations regarding ratemaking treatment for unrecovered Sibley costs at the time of the next Evergy West rate case or later cases.

Q. Did an unrecovered plant balance exist for Sibley as of the date of its retirement?

A. Yes.

Q. Did the Commission make any determinations concerning ratemaking treatment for Sibley unrecovered costs in its Order in Case No. EC-2019-0200?

A. No.

Q. When do you expect issues regarding ratemaking treatment of the unrecovered balance of Evergy West's Sibley coal unit to be brought forward for the Commission's consideration?

A. I expect those issues will arise in Evergy West's next general rate case, for which a notice has been filed by that utility last month in Case No. ER-2022-0130.

Q. Notwithstanding its inclusion in Mr. Graves Appendix A, does the order in Missouri Case No. EC-2019-0200 provide any sort of precedent for the ratemaking treatment sought by Empire for Asbury in this rate case?

A. Not in any way.

Q. Did the Commission make any finding in Case No. EC-2019-0200 regarding the prudence of Evergy West's decision to retire its Sibley unit?

A. No. The Order states:

> GMO chose to close the Sibley units, and the prudence of that decision is not at issue in this case. The question of prudence will be addressed in a future general rate case.

Q. Please summarize your conclusions regarding Mr. Graves Appendix A.

A. At best, Mr. Graves' Appendix A appears to support a conclusion that a wide range of PUCs in the U.S. have granted a wide variety of accounting and rate treatments to utilities either planning to retire coal units early or that have already retired those units. Based upon Staff's review, however, Appendix A does not support a finding that Empire's specific proposal in this case to receive both a return of and a return on its unrecovered Asbury investment is consistent with "mainstream" treatment of this category of cost by other PUCs, or that a consensus of PUCs have followed this approach.

Q. Mr. Graves' states at page 5 of his Direct testimony that "Each of these major investments [a 2008 Selective Catalytic Reduction (SCR) and a 2014 Air Quality Control System (AQCR)] were reviewed and approved by the Commission." Do you agree with that characterization?

A. Not entirely. In Case No. EO-2005-0263, involving the 2008 SCR investment, the Commission approved a Stipulation and Agreement in which "Empire agree[d] to undertake commercially reasonable efforts to make" certain investments, including the SCR at Asbury. Subject to a long list of conditions, the parties to that same Agreement merely agreed "that they will not take the position that the [SCR investment, among others] should be excluded from

Empire's rate base on the ground that the projects were not necessary at the time of this agreement, or that Empire should have used alternative technologies."

Q. Is Staff's proposed ratemaking for the unrecovered amount of the SCR investment at Asbury based upon a belief that this investment was not necessary in 2008, or on a belief that Empire should have used alternative technologies in 2008?

A. No.

Q. Have you attached a copy of the Commission's Report and Order and Stipulation and Agreement in Case No. EO-2005-0263 as Schedule MLO-2?

A. Yes.

Q. What about the Commission's Order in ER-2014-0351, referenced in Mr. Graves' testimony with regards to the AQCS?

A. In that case, the Commission ordered at page 11 that it would "adopt Staff's recommended in-service criteria and find the Asbury AQCS to be fully operational and used for service. Any party to Empire's next general rate case may argue the book value of Asbury AQCS. No party is precluded in Empire's next rate case from seeking any disallowance."

Q. Did any party to Empire's next rate case seek a disallowance of the AQCS investment?

A. No.

Q. Have you attached a copy of the Commission's *Report and Order* in Case No. ER-2014-0351 as Schedule MLO-3?

A. Yes.

Q. Does that conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Request of The Empire District Electric Company d/b/a Liberty for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in its Missouri Service Area	)))))	Case No. ER-2021-0312

AFFIDAVIT OF MARK L. OLIGSCHLAEGER

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

COMES NOW MARK L. OLIGSCHLAEGER, and on his oath declares that he is of sound mind and lawful age; that he contributed to the foregoing *Rebuttal Testimony of Mark L. Oligschlaeger;* and that the same is true and correct according to his best knowledge and belief.

Further the Affiant sayeth not.

Mark L. Oligschlaeger

MARK L. OLIGSCHLAEGER

JURAT

Subscribed and sworn before me, a duly constituted and authorized Notary Public, in and for the County of Cole, State of Missouri, at my office in Jefferson City, on this 20th day of December, 2021.

DIANNA L. VAUGHT
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: July 18, 2023
Commission Number: 15207377

Dianna L. Vaught

Notary Public

BEFORE THE PUBLIC UTILTIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF ADVICE LETTER NO. 1535 BY PUBLIC SERVICE COMPANY OF COLORADO TO REVISE ITS COLORADO PUC NO. 7 ELECTRIC TARIFF TO REFLECT REVISED RATES AND RATE SCHEDULES TO BE EFFECTIVE ON JUNE 5, 2009.	)	DOCKET NO. 09AL-299E

SETTLEMENT AGREEMENT

November 18, 2009

1, 2010. The Staff's HTY COS shall also be adjusted to include recovery of revenue requirements associated with the $42 million plant-in-service balance at December 31, 2009,[4] and other plant-related cost of service items, associated with SmartGridCity™ and the Company's forecasted $4.1 million of O&M expenses associated with SmartGridCity™ for 2010.

E. Treatment of Cameo, Zuni, and Arapahoe – Estimated Changes in Removal Costs and Future Cost Recovery.

In its direct case, Public Service proposed the following changes to its existing depreciation rates for steam production plant:

- Revise the retirement date for Arapahoe Units 3 and 4, Cameo Units 1 and 2, and Zuni Units 1 and 2.
- Update the estimated removal cost for the units listed above.
- Realign the accumulated reserve for depreciation to moderate the impact of the first two changes and to better align the reserve with current life statistics.
- Use a recovery period for the asset cost and expected removal costs for these three plants that is longer than the expected useful life to minimize the increase in depreciation for the new removal estimates.

In his Answer Testimony, Staff witness Eugene Camp expressed concern that the Company's updated estimates of the removal costs for the Cameo, Zuni and Arapahoe units were too high. Accordingly, he recommended that the Company eliminate the updated removal cost estimates from its COS and continue to use the

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[4] This amount represents the final rate base investment to complete SmartGridCity™. Ref. Hearing Transcript, Vol. I, page 128, and Vol. IV, pages 187-188.

previously approved depreciation rates. He also suggested a plan by which the Company could obtain future recovery of such costs once the site specific dismantling plans and associated costs were finally determined. The OCC also raised concerns about such costs and recommended elimination of the updated removal costs for the Zuni and Arapahoe units from the COS.

In Rebuttal Testimony, the Company agreed to withdraw its updated estimates of removal costs associated with the anticipated retirement of Cameo 1 and 2, Arapahoe 3 and 4 and Zuni 1 and 2 from its COS. With respect to updating the removal costs estimates, the Company sought approval of a process pursuant to which it would make a separate application to the Commission for approval of a site specific decommissioning plan for each plant to be retired. Each application would contain the following information: a site specific decommissioning plan, a proposed request for proposal ("RFP") for competitive acquisition of dismantling and removal services; a proposed amortization period for the decommissioning costs to be recovered and the expected revenue requirements associated with such recovery; and a proposed mechanism for recovery of the difference between the to be determined updated removal cost estimates and removal costs associated with these assets currently being recovered through base rates. The Company also apprised the Commission of its need for an order in this case approving the above-described process and explicitly authorizing the Company to recover any increase or decrease in removal costs approved as a result of the Company's decommissioning application in future rates.

In settlement of these issues, the Settling Parties agree that the Commission should approve the process proposed by the Company for development and approval of the site specific decommissioning plan and related costs for Cameo 1 and 2, Arapahoe 3 and 4 and Zuni 1 and 2, as described above. The Settling Parties also agree to recommend to the Commission that it include in its order entered in this proceeding, specific authorization for the Company:

1. To create and/or adjust a regulatory asset or liability for each plant by an amount equal to any difference between
    a. the level of depreciation expenses using the removal cost being recovered through the base rates approved in this proceeding associated with three plants; and
    b. the level of depreciation expense using updated or revised removal cost estimates required to be recognized by the Company in accordance with Generally Accepted Accounting Principles ("GAAP"); and
2. To recover a return of and a return on such regulatory asset or refund of any regulatory liability balance through a separate rate mechanism to be established at the time the removal costs are finally determined and approved.

F. Treatment of Cameo, Zuni, and Arapahoe - Depreciation Expense Other than Removal Costs.

In its Rebuttal Testimony, as part of its response to the Staff's recommendation to eliminate the updated removal estimates for Cameo 1 and 2, Arapahoe 3 and 4 and Zuni 1 and 2, Public Service proposed an increase in the depreciation rates included in the COS for each of these plants to reflect recovery of the total undepreciated plant balance for each of the units by the time each plant is proposed or expected to be retired.

In settlement of this issue, the Settling Parties agree that the depreciation rates for Cameo 1 and 2, Arapahoe 3 and 4 and Zuni 1 and 2 shall be the same as those approved by the Commission in Docket No. 06S-234EG and used as the basis for the Company's revenue requirement calculations in Docket No. 08S-520E. The Settling Parties further agree that to the extent that the Company is required to recognize a different level of depreciation expense for GAAP purposes than what is being recovered through its retail rates due to use of a shorter estimated remaining life of these plants, the Company shall be authorized to create a regulatory asset equal to the difference between the amount of depreciation expense being recovered through base rates associated with these assets and what the Company is required to recognize for GAAP purposes and to recover the return of and return on such regulatory asset in the Company's then next Phase 1 electric rate case. The Settling Parties agree that the length of time over which such regulatory asset will be recovered shall not exceed the life of each asset as reflected in current rates. Under this Settlement, the depreciation rates for all of the Company's steam production plant would remain the same as previously-approved by the Commission in Docket Nos. 06S-634EG and 08S-520E.

G. Low-Income Program.

The Settling Parties agree that the settled revenue requirement includes $4 million to fund a low-income program to be considered by the Commission in Phase 2 of this rate case.

Decision No. C09-1446

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

DOCKET NO. 09AL-299E

RE: THE TARIFF SHEETS FILED BY PUBLIC SERVICE COMPANY OF COLORADO WITH ADVICE LETTER NO. 1535 - ELECTRIC.

ORDER ADDRESSING PHASE I AND ECA ISSUES

Mailed Date: December 24, 2009
Adopted Dates: December 1, 3, and 22, 2009

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begin the process of dismantling and removing all generating stations within one year of plant retirement, stating it is too expensive. The OCC believes that if Public Service has no legal or regulatory obligation to dismantle and remove plant, customers are better served if the Company does not collect depreciation dollars for the plant's dismantling and removal.

115. Regarding the Settlement position on removal costs, the OCC states the record is completely devoid of evidence that these plants need to be removed. The OCC is not convinced Public Service will dismantle and remove the facilities at Arapahoe, Cameo and Zuni. The OCC is concerned that, if they are not removed, the Company's customers would have overpaid removal costs.

116. ACT disagrees with the Settlement's treatment of depreciation, arguing it is arbitrary and capricious, not supported by any evidence in the record, and contrary to established jurisprudence. ACT believes Public Service's retail customers will be paying an unjust and unreasonable amount for depreciation with no guarantee of recovering this overpayment if Public Service over earns its return on equity.

117. We find it proper to allow the Company to withdraw its request for recovery of increased removal costs. The process of addressing removal costs on a site-by-site basis will allow the Company's applications to be reviewed specifically for that project rather than in a generic manner. As a result, we adopt this portion of the Settlement without modification.

(2) Depreciation Expenses Other Than Removal

118. The Company initially proposed increased depreciation rates for Cameo 1 and 2, Arapahoe 3 and 4, and Zuni 1 and 2 with the goal of recovering the total undepreciated plant balance for each of these units by the time each plant is expected to be retired. Staff and the OCC both advocated for the continuation of current depreciation rates. Further, the OCC

opposed the use of year-end 2008 plant in-service balances and instead supported the use of a 13-month average balance in calculating depreciation expense for the *pro forma* adjustment to the HTY.

119. The Settlement proposes depreciation rates for all of the Company's steam production plants including Cameo 1 and 2, Arapahoe 3 and 4, and Zuni 1 and 2. These rates shall be the same as those approved by the Commission in Docket No. 06S-234EG and used as the basis for the Company's revenue requirement calculations in Docket No. 08S-520E. Additionally, to the extent the Company is required to recognize a different level of depreciation expense for Generally Accepted Accounting Practices (GAAP) purposes than what is being recovered through its retail rates (due to use of a shorter estimated remaining life of these plants), the Settlement requests authorization for the Company to create a regulatory asset. The regulatory asset would be equal to the difference between the amount of depreciation expense being recovered through base rates and what the Company is required to recognize for GAAP purposes. Further, the Company would recover the return of and return on the regulatory asset in the Company's next Phase I electric rate case. The Settling Parties agree the length of time over which the regulatory asset will be recovered shall not exceed the life of each asset as reflected in current rates.

120. Under this Settlement, a 13-month average balance will be used to calculate depreciation expense. No party to this rate case opposed this provision of the Settlement. Because we believe this manner of calculation is reasonable, we approve this portion of the Settlement without modification.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 215

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision.	ORDER

DISPOSITION: STIPULATIONS ADOPTED

I. INTRODUCTION

In this order, the Public Utility Commission of Oregon (Commission) adopts six uncontested stipulations resolving all issues raised by a request for a general rate revision filed by Portland General Electric Company (PGE). Adoption of these stipulations results in an increase in PGE's revenue requirement of about $100.2 million (5.9 percent), excluding power costs. Including power costs, which were reduced by about $35 million based on final forecasts, the overall increase in PGE's revenue requirement is approximately $65.2 million. This equates to an overall increase in PGE's rates of approximately 3.9 percent.[1] This order also extends PGE's existing decoupling mechanism for a period of three years.

II. BACKGROUND AND PROCEDURAL HISTORY

PGE is an electric company and a public utility in Oregon as defined in ORS 757.005, and is subject to the Commission's jurisdiction over the prices and terms of electric service to its Oregon retail customers. PGE provides service to approximately 816,000 retail customers in Oregon.

PGE filed its request for a general rate revision on February 16, 2010. PGE proposed an increase in its revenue requirement of $157.8 million (9.4 percent), excluding power costs. PGE also proposed a 10.5 percent rate of return on equity, modifications to its power cost adjustment mechanism (PCAM), an extension of its decoupling mechanism, and implementation of various accounting mechanisms.

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[1] PGE's revision to its annual net variable power costs was filed with its general rate request, but a different procedural schedule was adopted for that portion of the proceedings. The Commission adopted the stipulation governing annual net variable power costs in Order No. 10-410. PGE's final forecast of its net variable power costs for 2011 results in a $35 million decrease in PGE's revenue requirement. *PGE's Final MONET Update for 2011* (Nov 15, 2010).

directors' fees, director and officer insurance premiums, and franchise fees, and adjustments to PGE's interest expense on its debt.[5]

5. *Capital Cost Adjustments*

The stipulation makes a number of adjustments to capital costs. First, the stipulation reduces depreciation expense by $5.94 million and increases average rate base by $2.97 million. This adjustment is based on the depreciation rates approved by the Commission in docket UM 1458.

The stipulation also reduces PGE's average rate base by $34.59 million and reduces depreciation expense by $1.14 million based on updated capital costs associated with the Biglow Canyon Phase 3 wind farm. As part of the stipulation, the parties also agree that certain glass insulators should be reclassified as capital costs, rather than O&M, because their useful life exceeds one year. This reclassification increases average rate base by $0.51 million.

6. *Boardman Tariff*

Because PGE was originally expected to operate its Boardman coal-fired generating plant (Boardman) through the end of the plant's estimated useful life, PGE's remaining undepreciated investment in the plant is being recovered in rates through 2040. Given changing environmental regulations, PGE may cease operating the plant much earlier than 2040. To allow rates to reflect a shortened operating life, PGE proposed a Boardman Depreciation Revenue Requirement Tariff (Schedule 145) in this case. The tariff provides a mechanism to allow the Commission to authorize rate changes to reflect the incremental revenue requirement effect of a shortened operating life.

In the stipulation, PGE, Staff, and CUB recommend that the Commission approve the Boardman tariff as proposed. ICNU and Kroger did not sign onto this part of the stipulation, but did not oppose it.

B. Second Revenue Requirement Stipulation

The Second Revenue Requirement Stipulation addresses all remaining contested revenue requirement issues in the docket except power costs.[6] It is attached hereto as Appendix B.

[5] *See* Stipulating Parties/200, Johnson-Jenks-Tinker/8-9 (July 30, 2010) .
[6] *See* Order No. 10-410.

COMMISSIONERS:

TIM G. ECHOLS, CHAIRMAN
CHUCK EATON
H. DOUG EVERETT
STAN WISE

FILED
MAR 26 2012
EXECUTIVE SECRETARY
G.P.S.C.

DEBORAH K. FLANNAGAN
EXECUTIVE DIRECTOR

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Georgia Public Service Commission

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DOCKET # 34218

DOCUMENT # 141220

Docket No. 34218, Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the Power Purchase Agreements with BE Alabama, LLC from the Tenaska Lindsay Hill Generating Station and with Southern Power Company from the Harris, West Georgia and Dahlberg Electric Generating Plants and Updated Integrated Resource Plan

FINAL ORDER

APPEARANCES

Georgia Public Service Commission Public Interest Advocacy Staff: Amy Burns, Esq. and Jeffrey Stair, Esq.; ***Georgia Power Company***: Kevin C. Greene, Esq., Brandon F. Marzo, Esq., and Jack Jirak, Esq.; **Georgia Association of Manufactures**: Charles B. Jones, III, Esq.; ***Georgia Industrial Group***: Randall D. Quintrell, Esq.; ***Georgia Watch***: Clare McGuire, Esq. ***Resource Supply Management:*** Jim Clarkson; ***Southern Alliance for Clean Energy***: Nathaniel H. Hunt, Esq. and Jill Tauber, Esq.

BY THE COMMISSION:

I. STATEMENT OF PROCEEDINGS

This matter comes before the Georgia Public Service Commission ("Commission") on Georgia Power Company's ("Georgia Power" or the "Company") Application for Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C, Application for Certification of the various exhibits entered by all the parties and makes the following findings of fact and conclusions of law.

A. Decertification of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C

Pursuant to O.C.G.A. § 46-3A-6, Georgia Power Company has requested decertification of Plant Branch Units 1 and 2 and Plant Mitchell Unit 4C. (App. 63). According to the Company, the decision to retire the units included a number of factors, including the uncertainty related to environmental regulations, fleet operational flexibility, reliability considerations, fuel diversity, fuel price volatility, impacts on the community, employment and age of the units. (App. 63).

The decision to retire Plant Branch Units 1 & 2 is driven by environmental control requirements imposed by the Georgia Multipollutant Rule. Under the Multipollutant Rule, Plant Branch Units 1 & 2 require Selective Catalytic Reduction and scrubbers in place by December 31, 2013 and October 1, 2013, respectively. However, the financial analysis performed by the Company demonstrates that installation of such controls is significantly more costly than securing replacement generation.

Plant Mitchell Unit 4C is a small 33 MW unit that experienced a significant equipment malfunction in late 2009. In light of the age of the unit and the challenges associated with repair and continued operation, it is also in the best interest of customers to retire Plant Mitchell Unit 4C at this time.

The Company also seeks certain accounting treatment of three items associated with the decertification of these units. In terms of accounting treatment, the Company has requested the following regarding the retirement of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C:

1) Reclassification of the remaining net book values of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C as of their respective retirement dates to regulatory asset accounts and permission to amortize such regulatory asset accounts over a period equal to the respective unit's remaining useful life approved by the Commission in Docket No. 31958;

2) Second, the Company has moved a Construction Work In Progress ("CWIP") balance of $12.4 million directly attributable to Plant Branch Units 1 and 2 for environmental controls that will no longer be completed to a regulatory asset account. The Company seeks to amortize the $12.4 million balance ratably over three years beginning January 2014.

3) Third, the Company also seeks to reclassify unusable materials and supplies inventory remaining at the unit retirement dates as a regulatory asset, to be amortized ratably over a three year period beginning January 2014. (Ap. 66-67).

PIA Staff did not opposed to the Company's request to recover the net book value of the decertified units, the Plant Branch CWIP balance and the unusable materials and supplies inventory cost. (Tr. 433). Based on the language of the stipulation from the 2010 Rate Case, PIA Staff agrees that the Commission may set the amortization period for the regulatory assets which the Company has provided a known amount to be amortized. However, the amount of unusable materials and supplies inventory is not currently known. (Tr. 163-164, 169-172) Given the uncertainty of the amount in question, PIA Staff argued that the Commission should not set the amortization period for the unusable materials and supplies inventory at this time. Resource Supply Management and Georgia Watch both recommended that the Commission deny Georgia Power's request.

According to Company Witness testimony during cross-examination, the Company is undertaking measures to manage down this materials and supplies inventory. (T.709). Additionally, the Company states that it needs to maintain a certain supply of inventory to make sure the units can operate reliably until they are retired.

Given the uncertainty of the amount in question, the Commission finds it is reasonable not to the amortization period at this time. This finding does not violate the Commission Order in the 2010 Rate Case because the language stating that "any impairment losses and any unusable materials and supplies inventories at such units will be deferred as a regulatory asset to be recovered over a period deemed appropriate by the Commission at that time" is open to interpretation.

The Commission finds that the remaining net book value of Plant Branch Units 1 & 2 and Plant Mitchell Unit 4C shall be classified as a regulatory asset and that the costs be amortized over a period equal to the respective unit's remaining useful life approved by the Commission in Docket No. 31958. The Commission further approves Georgia Power's request for a three year recovery period (beginning January 2014) for approximately $12.4 million of Plant Branch Unit 1 & 2 environmental CWIP, which has been reclassified as a regulatory asset in accordance with the Commission's Order in Docket No. 31958. Finally, the Commission finds that the Company's request to reclassify unusable materials and supplies inventory remaining at the unit retirement dates as a regulatory asset shall be granted; however, the Commission denies the Company's request to set an amortization period at this time.

B. Baghouse Project Expenditures

In its application, the Company requests approval of expenditures to begin installation of baghouses on Plant Bowen Units 1- 4, Plant Wansley Units 1 and 2, and Plant Hammond Units 1-4. (Application (App.) 21-22). The Company seeks to spend roughly 15% of the total baghouse project costs between January 2012 and the middle of 2013, up to the approval date of the next IRP where potential further expenditures related to environmental controls may be addressed. It is concerned the work must begin immediately to meet an aggressive MACT rule compliance

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates — 6690-UR-123

FINAL DECISION

This is the Final Decision in the application of Wisconsin Public Service Corporation (WPSC) for authority to increase Wisconsin retail electric and natural gas rates in 2015.

Final electric rate changes are authorized consisting of a $24,602,000 annual rate increase for Wisconsin retail electric operations, a 2.5 percent increase. Final natural gas rate changes are authorized consisting of a $15,363,000 annual rate decrease for Wisconsin retail natural gas operations, a 4.3 percent decrease.

Introduction

On April 1, 2014, WPSC filed a request for authority to increase its Wisconsin retail electric rates by $76,809,000, an 8.0 percent increase, and to decrease its Wisconsin retail natural gas rates by $1,624,000, a 0.5 percent decrease, to be effective January 1, 2015. These rate changes are based on a 10.60 percent return on common equity.

On May 6, 2014, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. On September 10, 2014, public hearings were held in Madison, Wisconsin, for members of the general public and for the parties in this proceeding. The Commission received over 300 comments from members of the public as part of the Commission's public hearing process that included the opportunity to submit written comments through the Commission's website or at the hearing, or to testify at the public hearing.

The Commission considered this matter at its open meeting of November 6, 2014.

WPSC acknowledged those issues and excluded hours with negative LMPs and used more recent basis differences (most recent 12 months of actual). It is reasonable for the Commission to require that the hours with negative LMPs be removed from the revenue calculation for Crane Creek revenues and that the basis differences should be based on the most recent 12 months of actual available at the time of the delayed exhibit.

Deferral of 2013 Underspending in Monitored Fuel

In its rate filing, WPSC included a deferral of $4,087,000 for underspending of monitored fuel costs from 2013 over 2015 and 2016. In the Final Decision in Docket 6690-UR-121, the Commission ordered WPSC to refund the remaining underspending amount in the next month (based on August 2014 sales) as opposed to allowing WPSC to spread the refund over 2015 and 2016. Therefore, it is reasonable to remove the deferral from the 2015 revenue requirement.

NYMEX Update

WPSC requested permission to update fuel costs for forecasts of coal, rail, and natural gas costs on electric fuels costs, purchased power costs, purchased capacity costs, risk management costs, opportunity sales revenues and interruptible revenue credits. WPSC filed a delayed exhibit based on NYMEX futures costs as of October 15, 2014. It is reasonable to update fuel costs for the impact of the information contained in WPSC's delayed exhibit. (Ex.-WPSC-Guntlisbergen-3, PSC REF#: 223478.)

Retirement of power plants

A consent decree with the United States Environmental Protection Agency requires WPSC to repower, refuel or retire Pulliam units 5 and 6 and Weston unit 1 by June 1, 2015. WPSC has decided to retire these units.

The undepreciated balance of retired plant associated with these units on May 31, 2015, is expected to be $11.9 million.[1] The authorized test year revenue requirement includes $1,596,000 of depreciation expense related to these units, or $133,000 per month. The Commission authorizes WPSC to defer the actual undepreciated balance and amortize at an amount of $133,000 per month, starting with the actual retirement date, and concluding when the balance is fully amortized.

ICE project

ICE is a large software project undertaken by Integrys Business Support, LLC (IBS), to standardize the customer information systems across all Integrys companies. The project's benefits include numerous technology upgrades, functional improvements, and enhanced customer data security. WPSC estimates a total of $10.8 million of test-year expenses for the ICE project, including depreciation and return, contractors and consultants, software purchases, and projected labor from new hires.

Cost savings resulting from ICE are not projected to begin until 2016, due to 2015 being a stabilization period, involving a greater amount of billing work, calls to the call center, and collection activity, as well as lower productivity as employees adapt to the new processes.

Commission staff originally proposed disallowing the entire cost of the ICE project, due to lack of demonstrated ratepayer benefit. The Commission finds that information supplied after staff's audit demonstrates the necessity of the ICE project and therefore the Commission will not disallow the entire ICE project costs. Given this demonstrated need, the remaining relevant

[1] The amount would be different if the timing of the retirement varies from May 31, 2015.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE APPLICATION OF BLACK HILLS POWER, INC. FOR APPROVAL OF DEFERRED ACCOUNTING FOR COSTS INCURRED DUE TO WINTER STORM ATLAS DAMAGE AND TO TRANSFER THE REMAINING PLANT BALANCE FOR THE SOON TO BE DECOMMISSIONED NEIL SIMPSON I, OSAGE, AND BEN FRENCH PLANTS TO A REGULATORY ASSET	))))))))))	**ORDER APPROVING DEFERRED ACCOUNTING FOR STORM DAMAGE COSTS AND TRANSFER OF REMAINING PLANT BALANCE FOR SOON TO BE DECOMMISSIONED PLANTS TO A REGULATORY ASSET** **EL13-036**

On November 15, 2013, the South Dakota Public Utilities Commission (Commission) received an Application by Black Hills Power, Inc. (BHP) requesting an accounting order allowing it to 1) accumulate and defer for potential recovery in base rate proceedings before the Commission its expenses incurred to repair damage and restore service to its customers as a result of Winter Storm Atlas and 2) transfer the remaining plant balance for the soon to be decommissioned Neil Simpson I, Osage, and Ben French plants to a regulatory asset.

On November 21, 2013, the Commission electronically transmitted notice of the filing and the intervention deadline of December 6, 2013, to interested individuals and entities on the Commission's PUC Weekly Filings electronic listserv. No parties sought intervention or filed comments. On January 2, 2014, the Commission's staff (Staff) filed its memorandum regarding its recommendations for this docket.

The Commission has jurisdiction over this matter pursuant to SDCL Chapter 49-34A, specifically 49-34A-7.

At its regularly scheduled meeting on January 7, 2014, the Commission considered this matter. Staff recommended that the Commission approve BHP's requests with the conditions recommended in Staff's Memorandum. The Commission voted unanimously to allow BHP to use deferred accounting for costs incurred as a result of Winter Storm Atlas and authorize BHP to transfer the remaining plant balance for the soon to be decommissioned Ben French, Osage, and Neil Simpson I plants to a regulatory asset, including spare parts inventory, with the following conditions:

1. The accounting methods and the resulting regulatory assets shall not preclude Commission review of these amounts for reasonableness for rate recovery in any determination of rates, including both rate filings by BHP and rate reviews initiated by the Commission and does not guarantee any such recovery.

2. The allowance of a deferral/amortization accounting method and the resulting creation of a regulatory asset, after the related costs have been incurred, as is the case with the storm damage costs, is not to be interpreted as allowing future post expenditure deferrals. The Commission's decision in this case is based on the facts of this case and

any future allowance of the deferral/amortization accounting method and the resulting creation of a regulatory asset must be approved by the Commission.

It is therefore

ORDERED, that BHP is allowed to use deferred accounting for costs incurred as a result of Winter Storm Atlas and BHP is authorized to transfer the remaining plant balance for the soon to be decommissioned Ben French, Osage, and Neil Simpson I plants to a regulatory asset, including spare parts inventory, with the following conditions:

1. The accounting methods and the resulting regulatory assets shall not preclude Commission review of these amounts for reasonableness for rate recovery in any determination of rates, including both rate filings by BHP and rate reviews initiated by the Commission and does not guarantee any such recovery.

2. The allowance of a deferral/amortization accounting method and the resulting creation of a regulatory asset, after the related costs have been incurred, as is the case with the storm damage costs, is not to be interpreted as allowing future post expenditure deferrals. The Commission's decision in this case is based on the facts of this case and any future allowance of the deferral/amortization accounting method and the resulting creation of a regulatory asset must be approved by the Commission.

Dated at Pierre, South Dakota, this 9th day of January, 2014.

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this document has been served today upon all parties of record in this docket, as listed on the docket service list, electronically.

By: Joy Lashley

Date: 01.10.14

(OFFICIAL SEAL)

BY ORDER OF THE COMMISSION:

Gary Hanson

GARY HANSON, Chairman

Chris Nelson

CHRIS NELSON, Commissioner

Kristie Fiegen

KRISTIE FIEGEN, Commissioner

FILED AUG 29, 2016
DOCUMENT NO. 07092-16
FPSC - COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company.	DOCKET NO. 160039-EI ORDER NO. PSC-16-0361-PAA-EI ISSUED: August 29, 2016

The following Commissioners participated in the disposition of this matter:

JULIE I. BROWN, Chairman
LISA POLAK EDGAR
ART GRAHAM
RONALD A. BRISÉ
JIMMY PATRONIS

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING REQUEST TO CREATE REGULATORY ASSET
BY GULF POWER COMPANY

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code (F.A.C.).

Background

On February 24, 2016, Gulf Power Company (Gulf) filed a petition seeking approval to create a regulatory asset and defer recovery of the amounts related to the retirement of Plant Smith Units 1 and 2 (Units). The recovery of the regulatory asset would be deferred to a future proceeding with an effective date after the expiration date of the Stipulation approved in Order No. PSC-13-0670-S-EI,[1] which is the last billing cycle in June 2017. The decision to retire the Units was made after Gulf finalized its Mercury and Air Toxics Standards (MATS) rule compliance strategy for each of its coal-fired units. At December 31, 2015, the Net Book Value of the Units was approximately \$61.9 million and the estimated remaining inventory balance was \$2.9 million. In response to a staff data request, Gulf provided the actual net book value and actual remaining inventory balances of \$60,244,659 and \$2,809,649, respectively, as of the

[1] Order No. PSC-13-0670-S-EI, issued December 19, 2013, in Docket No. 130140-EI, In re: Petition for rate increase by Gulf Power Company.

actual retirement date of March 31, 2016.[2] The Office of Public Counsel is listed as an interested person in this docket.

This order addresses the creation of the regulatory asset and the deferral of its recovery to a future proceeding. We have jurisdiction over this matter pursuant to Sections 366.04 and 366.06, Florida Statutes (F.S.).

Decision

On February 24, 2016, Gulf filed a petition seeking approval to create a regulatory asset and defer recovery of the amounts related to the retirement of Plant Smith Units 1 and 2. Gulf's decision to retire the units was based on its MATS rule compliance strategy for its coal-fired generating units. Unit 1 began service in 1965 and was previously scheduled to be retired in 2030. Unit 2 began service in 1967 and was previously scheduled to be retired in 2032. Based on the MATS evaluation, the Units were retired on March 31, 2016. At December 31, 2015, the Net Book Value of the Units was \$61,880,482 and the estimated remaining inventory balance was \$2,852,159.

In its petition, Gulf asserts that its best option for compliance with MATS is the retirement of Plant Smith Units 1 and 2. Commission staff requested the MATS compliance alternatives that Gulf explored in an effort to determine the accuracy of this determination. In response to this request, Gulf submitted the Plant Smith Asset Evaluation, dated December 11, 2014.[3] After a review of the provided analysis, we are satisfied that the early retirement of Plant Smith Units 1 and 2 is the most cost-effective alternative.

Because the Units are being retired early, certain entries must be made to Gulf's books and records. Rule 25-6.0436(6), F.A.C., requires a utility to compile an annual depreciation status report showing changes to categories of depreciation that will require a revision. In addition, Rule 25-6.0436(7)(a), F.A.C., provides that:

> Prior to the date of retirement of major installations, the Commission shall approve capital recovery schedules to correct associated calculated deficiencies where a utility demonstrates that (1) replacement of an installation or group of installations is prudent and (2) the associated investment will not be recovered by the time of retirement through the normal depreciation process.

Gulf's current depreciation rates are based on retirement dates of 2030 and 2032 for the Units. Therefore, the investment in the Units will not be recovered through the normal depreciation process due to the early retirement of the Units.

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[2] Document No. 04002-16, filed June 24, 2016, in Docket No. 160039-EI, In re: Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company.

[3] Confidential Document No. 02442-16, filed April 25, 2016, in response to Staff's Second Data Request Item No. 1, in Docket No. 160039-EI, In re: Petition for approval of regulatory asset related to the retirement of Plant Smith Units 1 and 2, by Gulf Power Company

Pursuant to the Stipulation, Gulf's depreciation and amortization accrual rates in effect at that time remain in effect for the term of the Stipulation; therefore, the utility is prohibited from requesting an amortization rate until the Stipulation term expires.[4] However, the utility is required to reflect the retirement of the plant on its books and records. On July 14, 2016, Gulf filed a depreciation and dismantlement study that was assigned Docket No. 160170-EI.

In response to a staff data request, Gulf provided the actual net book value and actual remaining inventory balance of $60,244,659 and $2,809,649, respectively as the actual retirement date of March 31, 2016. Based on a review of Gulf's filing and its responses to Staff's First and Third Data Request, we find that the Units' Net Book Value of $60,244,659 and the remaining inventory balance of $2,809,649 represent the appropriate amounts of the proposed regulatory asset as of March 31, 2015.

Because the Stipulation does not allow Gulf to request an amortization rate during the term of the Stipulation, the early retirement of the Units will require that future revisions be made to the depreciation rates, amortization, and capital recovery schedules. Gulf is generally not required to file any depreciation or dismantlement studies before December 31, 2018. The concept of deferral accounting allows companies to defer costs and seek recovery through rates at a later time. In this case, it is appropriate to create a regulatory asset for the amounts associated with the early retirement of the Units and defer recovery until an amortization rate can be established. Because of the specific circumstances of the Stipulation related to continuing depreciation and amortization rates, the creation of a regulatory asset does not involve deferral of costs that would otherwise be recovered, in part, during the term of the Agreement. At our August 9, 2016 Agenda Conference, OPC represented that the early retirement of the Units was discussed as a possibility during settlement negotiations with Gulf in Docket No. 130140-EI, and can be fairly construed as having been considered in the context of the continuation of depreciation and amortization rates.

In light of the foregoing, we hereby approve Gulf's request to create a regulatory asset related to the retirement of Plant Smith Units 1 and 2 and defer the recovery of the regulatory asset to a future proceeding. Further, our approval to record the regulatory asset for accounting purposes does not limit our ability to review the amounts and recovery period for reasonableness in future proceedings in which the regulatory asset is included.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Gulf Power Company's request to create a regulatory asset related to the retirement of Plant Smith Units 1 and 2 and defer the recovery of the regulatory asset to a future proceeding is hereby approved. Our approval herein does not limit this Commission's ability to review the amounts and recovery period for reasonableness in future proceedings in which the regulatory asset is included. It is further

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[4] Document No. 07112-13, filed November 22, 2103, in Docket No. 130140-EI, In re: Petition for rate increase by Gulf Power Company (pp.12-13).

ORDERED that the provisions of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that in the event this Order becomes final, this docket shall be closed.

By ORDER of the Florida Public Service Commission this 29th day of August, 2016.

Carlotta S Stauffer

CARLOTTA S. STAUFFER
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
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Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

JSC

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **CONSUMERS ENERGY COMPANY** for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief.	)))))	Case No. U-20165

At the June 7, 2019 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Daniel C. Scripps, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

On June 15, 2018, Consumers Energy Company (Consumers) filed an application, together with supporting testimony and exhibits, pursuant to 2016 PA 341 (Act 341); MCL 460.6t(3) and the Commission's December 20, 2017 and November 21, 2017 orders in Case Nos. U-15896 *et al.* and U-18418, requesting Commission approval of its integrated resource plan (IRP).[1]

A prehearing was held on July 16, 2018, before Administrative Law Judge Sharon L. Feldman (ALJ). The ALJ granted intervenor status to Michigan Environmental Council (MEC), the Sierra Club (SC), the Natural Resources Defense Council (NRDC), the Association of Businesses Advocating Tariff Equity (ABATE), Energy Michigan, Inc. (Energy Michigan), Michigan Energy

[1] MCL 460.6t is subsequently referred to as "Section 6t" throughout this order.

settlement proceeding that a settlement agreement that both: (1) makes specific determinations regarding PURPA issues that will affect solar QF developers, and (2) has no solar QF represented as a signatory, cannot be deemed to adequately represent the public interest. The Commission disagrees. The signatories to the settlement agreement represent a broad cross section of interests and include the utility and the Staff, as well as environmental organizations, QFs, an association that represents commercial and industrial interests, and the Attorney General, who is charged with representing Michigan ratepayers. The Commission also notes that the Michigan Court of Appeals has, in the past, affirmed a Commission determination that the public interest was adequately represented by the Staff when the Staff was party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that those who signed the settlement agreement adequately represent the public interest.

In addition, the Commission believes that the settlement agreement is in the public interest. The Commission finds persuasive the testimony and arguments of Consumers and others that the settlement agreement was the result of ongoing arms-length negotiations that resulted in significant compromises by all involved. This is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. The various compromises reached in this settlement agreement that the Commission views to be in the public interest include all of the following:

- An agreement that Consumers retire Karn 1 and 2 in 2023, which will result in significant savings to ratepayers, reduces pollution, and advances the utility's clean energy goals and the public's interest in clean and reliable energy.

- An agreement that provides potential customer savings by Consumers agreeing to seek recovery of the unrecovered book value and decommissioning costs of Karn 1 and 2 through low-cost debt financing in a separate proceeding, rather than continued recovery through traditional ratemaking which includes a return on these assets.
- An agreement to continue to evaluate the cost-effectiveness of existing coal plants by requiring Consumers to conduct a retirement analysis of Campbell 1 and 2 in its next IRP that will use several assumptions set forth in the settlement agreement, as well as an agreement that, based on the results of this forthcoming analysis, Consumers may retire those units in 2025 or earlier, much sooner than the four-year lag time that the utility originally deemed necessary in order to retire them.
- An agreement that includes $29,952,957 in identified capital costs for expanded DR and CVR programs over the next three years, limits risk to ratepayers by not preapproving O&M costs associated with Consumers' CVR, DR, and EWR programs, and further provides that the capital costs associated with these resources will be subject to annual reporting requirements, and requires Consumers to conduct additional studies to determine best practices regarding the amount of reserves that could be provided by DR and to assess the potential changes in the frequency or duration of curtailments and the role of DR in meeting peak demand.
- A significantly-reduced and transparent FCM on PPA payments that complies with Section 6t(15) and removes the disincentive for Consumers to enter into long-term PPAs with third parties, including renewal of long-term PPAs with existing QFs.

in the next IRP. A holistic review of energy infrastructure options and customer trends, such as adoption of renewable energy, EWR, and electric vehicles, is essential to optimize investments for the benefit of ratepayers.

The Commission has reviewed the settlement agreement and finds that the public interest is adequately represented by the parties who entered into the settlement agreement. The Commission further finds that the settlement agreement is in the public interest, represents a fair and reasonable resolution of the proceeding, is supported by substantial evidence on the whole record, and should be approved.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Exhibit A, is approved.

B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.

C. In accordance with paragraph 7(h) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 7(h), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF NEW MEXICO'S ABANDONMENT OF SAN JUAN GENERATING STATION UNITS 1 AND 4	)))	**Case No. 19-00018-UT**

FINAL ORDER ON REQUEST OF PUBLIC SERVICE COMPANY OF NEW MEXICO FOR AUTHORITY TO ABANDON ITS INTERESTS IN SAN JUAN GENERATING STATION UNITS 1 AND 4 AND TO RECOVER NON-SECURITIZED COSTS

THIS MATTER comes before the New Mexico Public Regulation Commission ("Commission" or "NMPRC") on the February 21, 2020 Recommended Decision issued by Hearing Examiners Ashley Schannauer and Anthony Medeiros on Public Service Company of New Mexico's (PNM) Request for Authority to Abandon Its Interests in San Juan Generating Station Units 1 and 4, included as part of PNM's July 1, 2019 Consolidated Application for Approvals for the Abandonment, Financing, and Resource Replacement for San Juan Generating Station pursuant to the Energy Transition Act ("Application"). The Commission, having reviewed the Recommended Decision (RD), the Application and being otherwise duly informed, **FINDS:**

1. The Commission has jurisdiction over the parties and the subject matter of this case.

2. On February 21, 2020, the Hearing Examiners issued an Order Shortening Deadline for Filing Exceptions and Addressing Deadline for Final Commission Action which required exceptions to be filed by March 3, 2020 and responses to exceptions to be filed by March 6, 2020.

3. No exceptions to the Recommended Decision on the Request for Authority to Abandon Its Interests in San Juan Generating Station Units 1 and 4 were filed.

4. The Recommended Decision on the Request for Authority to Abandon Its Interests in San Juan Generating Station Units 1 and 4

IT IS THEREFORE ORDERED:

A. The Recommended Decision on the Request for Authority to Abandon Its Interests in San Juan Generating Station Units 1 and 4, including the Statement of the Case, Discussion, Findings of Fact and Conclusions of Law, and Decretal Paragraphs recommended by the Hearing Examiner, including the Financing Order, are well taken and are hereby incorporated by reference as if fully set forth in this Final Order, and are ADOPTED, APPROVED, and ACCEPTED as the Findings, Conclusions and Orders of the Commission.

B. All pending motions, requests or any other matter not expressly ruled on or addressed in the hearing or in the discussion of this Final Order herein are hereby deemed denied and disposed of consistent with the discussion of this Final Order.

C. This Order is effective immediately.

D. Copies of this Order shall be served on all persons listed on the attached Certificate of Service, via e-mail to those whose e-mail addresses are known, and otherwise via regular mail.

ISSUED under the Seal of the Commission at Santa Fe, New Mexico, this 1st day of April, 2020.

NEW MEXICO PUBLIC REGULATION COMMISSION

/s/ Cynthia B. Hall, electronically signed
CYNTHIA B. HALL, COMMISSIONER DISTRICT 1

/s/ Jefferson Byrd, electronically signed
JEFFERSON L. BYRD, COMMISSIONER DISTRICT 2

/s/ Valerie Espinoza, electronically signed
VALERIE ESPINOZA, COMMISSIONER DISTRICT 3

/s/ Theresa Becenti-Aguilar, electronically signed
THERESA BECENTI-AGUILAR, COMMISSIONER DISTRICT 4

/s/ Stephen Fischmann, electronically signed
STEPHEN FISCHMANN, COMMISSIONER DISTRICT 5

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF PUBLIC SERVICE COMPANY OF MEXICO'S ABANDONMENT OF SAN JUAN GENERATING STATION UNITS 1 AND 4	)))))	**Case No. 19-00018-UT**

RECOMMENDED DECISION ON PNM'S REQUEST FOR ISSUANCE OF A FINANCING ORDER

February 21, 2020

ultimate persuasion. The quantum of proof in administrative adjudications is, again unless expressly provided otherwise, a preponderance of record evidence.[31]

III. ISSUES AND RECOMMENDATIONS

A. Summary of Recommendations

This Recommended Decision presents a case of first impression. It applies a new statute, the ETA, for the first time. As a result, this decision interprets the statute for the first time and applies new concepts to the regulation of a public utility abandoning its interest in a generating plant of electricity and the recovery of costs associated with the abandonment. Accordingly, many of the concepts addressed herein are new. The Hearing Examiners provide the following summary to help with the understanding of some relatively complex and novel matters.

The Recommended Decision, if approved by the Commission, would address five main issues. First, it would allow PNM to include in bonds (securitization) to be issued by a PNM affiliate (a special purpose entity) the $360.1 million PNM estimates as the costs to abandon its interest in the remaining San Juan Units (San Juan Units 1 and 4). This would include the full $283 million

[31] *See* Davis, *supra,* § 16.9 at 256 ("One can *never* prove a fact by something less than a preponderance of the evidence") (emphasis in original). *See El Paso Electric Co. et al. v. N.M. Pub. Serv. Comm'n*, 1985-NMSC-085, ¶ 12 ("This Court, however, does express its deep concern regarding the reasonableness of this heightened standard of proof ['clear and convincing evidence'], especially *since a 'preponderance of evidence' standard is customary in administrative and other civil proceedings.*") (emphasis added); *Re Southwestern Public Service Co.,* Case No. 2678, Recommended Decision of the Hearing Examiner (Nov. 15, 1996) ("No matter how the Commission describes its standard of review, SPS bears the burden of proof in this case. SPS must demonstrate that a preponderance of evidence exists in the record on which to base approval of the requested authorizations surrounding the merger.").

The prevailing evidentiary standard of proof for decisions rendered in administrative agency adjudications should not be confused with the standard of "substantial evidence in the record as a whole," the appellate standard of review applied by the New Mexico Supreme Court in reviewing Commission orders. *See, e.g., New Mexico Indus. Energy Consumers v. PSC*, 1986-NMSC-059, ¶ 32 (". . . *our review* of Commission decisions must be based on *substantial evidence in the record as a whole*") (emphasis added); *New Mexico Exchange Carrier Group v. N.M. Public Regulation Comm'n,* 2016-NMSC-015, ¶ 13 ("A party *challenging a PRC Order* must establish that the order is arbitrary and capricious, *not supported by substantial evidence*, outside the scope of the agency's authority, or otherwise inconsistent with law.") (emphasis added; internal quotation marks and citation omitted). *See also* Davis, *supra* § 16.9 at 256 ("The requirement of 'clear, unequivocal, and convincing evidence' imposed by the Woodby case applies only to the agency, not to the reviewing court; the standard of substantial evidence applies at the court level. Espinoza-Espinoza v. Immigration and Naturalization Service, 554 F.2d 921, 924 (9th Cir. 1977).'").

estimate of undepreciated investment in the units. The bonds would be issued shortly after the abandonment of PNM's interest in the units on July 1, 2022.

Second, the decision would also authorize PNM to collect Energy Transition Charges (ETCs) to pay the debt service on the bonds over a 25-year period. The Hearing Examiners recommend the adoption of PNM's ETC proposal which, for residential customers, would assess a $1.90 per month charge for customers using less than 900 kWh per month and $4.97 per month for customers using more. The ETCs would be adjusted periodically over the 25-year collection period, as needed to reflect changes in total PNM customer consumption, to ensure that the debt service payments are made in full and on time. The ETCs would be charged shortly after the bonds are issued.

Third, the decision provides that PNM will immediately reduce its base rates to eliminate all of the costs of San Juan Units 1 and 4 at the time it starts charging the ETCs. This reduction would more than offset the additional cost of the ETCs.

Fourth, as required by the ETA, the decision would establish a process to adjust PNM's base rates in the future to reconcile any differences between the estimated costs recovered in the bonds and PNM's actual costs. This process would include the opportunity to review the reasonableness and prudence of costs that have not, prior to this case, already been reviewed for reasonableness and prudence. The review would consider the reasonableness and prudence of the costs PNM incurs in the future for plant decommissioning and coal mine reclamation.

Fifth, included in the costs to be included in the bonds are $20 million in severance and job training costs for PNM and coal mine employees and $19.8 million in payments to state administered energy transition funds for Indian affairs, economic development and displaced workers. The decision would allow PNM to make those payments as soon as needed prior to the issuance of the bonds.

The cost savings from abandoning San Juan Units 1 and 4 are large enough to offset the added costs of the ETCs and PNM's proposed portfolio of replacement resources. Thus, the immediate impact of the securitization and abandonment should be a net savings in customers' monthly bills. PNM estimates the savings for an average residential customer using 600 kWh per month and paying the $1.90 per month ETC should approximate $6.87 per month on their current monthly bill of $73.25. Even the residential customer using 1,000 kWh per month and paying the higher $4.97 per month ETC should see a savings of $9.65 per month on their current monthly bill of $129.03 per month.

The approach recommended by the Hearing Examiners – immediate credits to eliminate the full costs of the abandoned plant when the ETCs are first assessed – will produce the savings immediately. PNM's proposal would credit the capital costs of the abandoned plant at the time the ETCs are assessed but credit the annual operating, maintenance, and tax expenses in a subsequent rate case decision.

The overall impact on customer bills is less clear, given PNM's announced intent to file general rate cases in the Spring of 2020 (with new rates to become effective in the Spring of 2021) and the Summer of 2021 (with new rates to become effective in the Summer of 2022).

The Recommended Decision addresses PNM's securitization request here in a separate order as required by the ETA. The ETA also requires that the Commission's final order addressing the Recommended Decision give PNM an unspecified amount of time to accept the changes the Commission adopts from PNM's proposal. This Recommended Decision proposes that the time to respond be set at ten calendar days.

In a separate Recommended Decision being issued today, the Hearing Examiners recommend that PNM's request to abandon its interest in San Juan Units 1 and 4 be approved. The abandonment approval would only apply to PNM's interest in the plant and would not interfere with the efforts of the City of Farmington and Enchant Energy to acquire the plant from PNM and the other San Juan owners and develop it with CCUS technology.

Finally, the Recommended Decisions issued today in this Case No. 19-00018-UT address PNM's requests for abandonment and securitization authority. As prefaced above, the hearings on these requests were conducted in December 2019. A second set of hearings was held in January 2020 in Case No. 19-00195-UT on PNM's request for the approval of replacement resources. A Recommended Decision on that request will be issued in the near future.

B. Constitutional Issues

1. Applicability of the ETA

Even before the Commission formally initiated this proceeding and the ETA was enacted, at least one party, NEE, was arguing that Article IV, Section 34 of the New Mexico Constitution prevented the application of what would become the ETA to this case because NEE contended there was already a pending abandonment proceeding relating to the San Juan coal plant.[32] That constitutional provision, entitled "Change of rights or procedure in pending cases," states: "No act of the legislature shall affect the right or remedy of either party, or change the rules of evidence or procedure, in any pending case."[33] CFRE and Staff subsequently joined NEE in arguing the ETA

[32] *See* NEE's Resp. to Pleading Filed by PNM & WRA on Jan. 18, 2019 Pursuant to Commission Order of Jan. 10, 2019 (Jan. 22, 2019) at 3-5 ("Thus, while the legislature is mandated to set the general framework within which the Commission shall regulate utility companies, the legislature does not have the authority or the expertise to determine the outcome or the procedure of a pending case. Any legislation that attempts to take that authority away would be unconstitutional. ... [T]he legislature cannot and should not enact laws that influence or determine the outcome of a case, such as a law that ensures that PNM gets 100% cost recovery for undepreciated assets on one or both of its coal investments. Those are not policy issues – those are case specific issues that are well within the purview of the Commission and would impact other pending cases, not just this abandonment case, that it alone has the expertise (after discovery, testimony, cross-examination, and all the due process requirements). Those who may try to pass such a law would be attempting to make an end-run around the constitutionally vested power of this Commission. They are on shaky grounds, not the Commission.") (internal citations omitted).

[33] N.M. Const. Article IV, § 34.

STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 2nd day of August, 2005.

In the Matter of The Empire District Electric Company's Application for Certificate of Public Convenience and Necessity and Approval of an Experimental Regulatory Plan Related to Generation Plant	)))))	**Case No. EO-2005-0263**

ORDER APPROVING STIPULATION AND AGREEMENT

Issue Date: August 2, 2005 Effective Date: August 12, 2005

Syllabus: This order approves the Stipulation and Agreement entered into among The Empire District Electric Company, the Staff of the Commission, the Office of the Public Counsel, Explorer Pipeline Company, Praxair, Inc., and the Missouri Department of Natural Resources with regard to Empire's participation in building the Iatan 2 generation plant, and making environmental upgrades to other plants.

Background

On February 4, 2005, Empire filed its Application with the Missouri Public Service Commission under Sections 386.250, 393.140, 393.170, 393.230 and 393.240, RSMo. Empire asked the Commission to approve its experimental regulatory plan concerning its possible participation in the Iatan 2 steam electric generation station, making environmental upgrades to other plants, and a certificate of convenience and necessity to participate in Iatan 2, if necessary.

Empire's Application asked the Commission to find that:

- Empire is allowed to maintain its debt at investment grade, and is able to adequately participate in the equity market;
- the Commission should not exclude Iatan Unit 1 and Asbury environmental upgrade investments from rate base on the ground that the projects were not necessary or timely or that Empire should have used alternative technologies;
- Empire's ownership of up to approximately 150 MW of new generation capacity at the Iatan site would have long-term benefits for maintaining competitively priced electricity for Missouri consumers and that the Commission should not exclude Empire's investment in Iatan Unit 2 and its V84 Combustion Turbine at Riverton from rate base on the ground that the projects were not necessary or timely, or that Empire should have used alternative technologies;
- the Signatory Parties[1] may agree to additional amortizations for Empire to help effectuate Empire's investment grade ratings during construction of Iatan 2;
- depreciation and amortization rates affect cash flow, and hence the ability to maintain investment grade status; thus, the Commission should review Empire's depreciation and amortization rates accordingly in Empire's future rate cases; and

[1] The Signatory Parties are Empire, the Staff of the Commission, Public Counsel, Explorer, Praxair, and the Department of Natural Resources.

- Empire may use the fuel and purchase power cost recovery mechanism authorized in Senate Bill 179[2] to recover fuel costs.

On April 12, the Commission directed that notice of Empire's Application be given to the public. The Commission allowed Praxair, Explorer, DNR, Union Electric Company d/b/a AmerenUE, Kansas City Power & Light Company, and Aquila, Inc., to intervene.

On June 22, Empire filed prepared direct testimony in support of its Application. On June 28, Empire amended its application and explained its proposed experimental regulatory plan in greater detail.

On July 18, 2005, Empire, the Staff of the Commission, the Public Counsel, Explorer, Praxair and DNR filed a Stipulation and Agreement (Agreement), which is Attachment 1 to this order. The Agreement purports to resolve all issues among the signatory parties.

The Stipulation and Agreement

The Agreement is among less than all parties to this case. But AmerenUE, KCPL and Aquila (all of the non-signatory parties) state that they do not oppose the Agreement and do not request a hearing.

The Agreement suggests that the Commission approve an experimental regulatory plan for Empire related to its participation in latan 2. latan 2 is a proposed new coal-fired generation unit with 800-900 MW of capacity to be located at the latan site near Weston, Missouri. KCPL is to construct latan 2.

[2] Act of April 27, 2005, 93rd General Assembly, SS SCS SB 179 (to be codified at § 386.266 RSMo, effective January 1, 2006).

The Agreement contains conditions related to:

- Empire's infrastructure investments, including Iatan 2, environmental investments in Iatan 1, a 155 MW gas-fired peaking plant in Riverton, Kansas, and installing Selective Catalytic Reduction equipment at the Asbury coal-fired generating station;
- Treatment of various issues in Empire's rate cases between now and when the investments related to Iatan 2 are reflected in rates, including an agreement that the signatory parties will not claim that the decision to build Iatan 2 was not prudent, but that they reserve the right to claim in a rate case that some or all of the expenses Empire incurs to build Iatan 2 are not prudent;
- The signatory parties' agreement to support, if necessary, an amortization that will minimize the cost of the plan while seeking to provide adequate cash flow for Empire to maintain its debt at investment grade;
- Empire's agreement to rely solely on Senate Bill 179 to recover its fuel and purchased power costs;
- Provisions related to Empire treating its off-system sales and transmission-related revenues "above the line" for ratemaking purposes for as long as its related investments and expenses are considered in determining rates;
- Provisions related to sulfur dioxide (SO_2) emission allowances;
- A detailed resource plan process for future needs; and

- A customer program collaborative process related to affordability, efficiency and demand response programs.

On July 21 and 22, 2005, the Commission held a hearing concerning the Agreement.

Discussion

The Commission has the legal authority to accept a stipulation and agreement to resolve a case.[3] The Commission notes that "[e]very decision and order in a contested case shall be in writing and, except in default cases or cases disposed of by stipulation, consent order or agreed settlement . . . shall include . . . findings of fact and conclusions of law."[4] Consequently, the Commission need not make findings of fact or conclusions of law in this order.

If no party objects to a stipulation and agreement, the Commission may treat the Agreement as unanimous.[5] Because all parties have either signed the Agreement filed on July 18, 2005 or stated that they do not oppose the agreement, the Commission will treat the Agreement as unanimous.

KCPL has identified Empire as a "preferred potential partner in the Iatan 2 generating plant project" if Empire has a "commercially feasible financing plan for meeting [its] financial commitments to participate in the ownership of the Iatan 2 plant by the later of August 1, 2005 or such date that KCPL shall issue its request(s) for

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[3] *See* Section 536.060, RSMo 2000.

[4] Section 536.090, RSMo 2000.

[5] 4 CSR 240-20115(2)(C).

proposal(s) related to Iatan 2."[6] On June 10, 2005, Empire entered into a Letter of Intent with KCPL for a preferred capacity of 150 MW and a minimum allocation of 100 MW ownership in Iatan 2. The LOI is contingent upon providing an acceptable financing and regulatory plan and the execution of acceptable ownership, operating and common facility agreements.[7]

The Agreement assists Empire in meeting its needs for generation so that it can achieve its energy and capacity requirements. This Agreement gives Empire an opportunity to own at least 100 MW of coal-fired generation to be built in Missouri.

The Agreement strikes a reasonable and appropriate balance between the interests of Empire's customers and shareholders regarding Empire's participation in Iatan 2. The Agreement is designed to positively impact Empire's credit ratings. Thus Empire should have lower debt costs to pass on to consumers in the form of lower future rates.

Furthermore, the Agreement is designed to give Empire the opportunity to maintain its investment grade ratings during the term of the experimental regulatory plan, which is important to Empire's shareholders and creditors. This Agreement also protects Empire's customers from potential imprudent or unreasonable actions by recognizing that the Commission may disallow expenses, including, but not limited to, "generation investments . . . , related costs and off-system sales margins on the ground

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[6] Gipson Direct (Ex. 2, p. 5).

[7] *Id.* at 6.

that Empire failed to acquire more coal-fired resources at an earlier date,"[8] in rate cases Empire may file.

The Commission has reviewed the First Amended Application, the Agreement, and the evidence received at the hearing. Based upon its review, the Commission concludes that the Stipulation and Agreement filed on July 18, 2005 is in the public interest. The Commission will therefore approve the Agreement and direct that the parties to the Agreement comply with its terms.

IT IS THEREFORE ORDERED:

1. That the Stipulation and Agreement entered into among The Empire District Electric Company, the Staff of the Commission, the Office of the Public Counsel, Explorer Pipeline Company, Praxair, Inc., and the Missouri Department of Natural Resources, on July 18, 2005, is approved.

2. That the parties to the Stipulation and Agreement shall comply with its terms.

3. That this order shall become effective on August 12, 2005.

4. That this case may be closed on August 13, 2005.

BY THE COMMISSION

Colleen M. Dale
Secretary

(S E A L)

Davis, Chm., Murray, Clayton and Appling, CC., concur
Gaw, C., concurs in part; dissents in part; dissent to follow

Pridgin, Regulatory Law Judge

[8] Stipulation and Agreement, Section III.C.7, page 5.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company's Application for Certificate of Public Convenience and Necessity and Approval of an Experimental Regulatory Plan Related to Generation Plant.	)))))	Case No. EO-2005-0263

STIPULATION AND AGREEMENT

COME NOW The Empire District Electric Company (Empire), the Missouri Department of Natural Resources (MDNR), the Staff of the Missouri Public Service Commission (Staff), Praxair, Inc. (Praxair), Explorer Pipeline Company (Explorer) and the Office of the Public Counsel (Public Counsel) (collectively "the Signatory Parties"), and submit this Stipulation and Agreement (the Agreement) to the Missouri Public Service Commission (Commission) for its consideration and approval:

I. BACKGROUND

On February 4, 2005, Empire filed an application with the Commission seeking Commission approval of an experimental regulatory plan concerning its possible participation in a steam electric generation station (Iatan 2), or other baseload generation options, and seeking a certificate of convenience and necessity to participate in Iatan 2, if necessary. By its Order Establishing Intervention Period issued April 12, 2005, the Commission directed that notice of Empire's Application be given to the public.

II. KCPL ACTIVITIES

The Stipulation and Agreement in the KCPL regulatory plan case (Case No. EO-2005-0329) identifies Empire as a "preferred potential partner in the Iatan 2 generating plant project" if Empire has a "commercially feasible financing plan for meeting [its] financial commitments to participate in the ownership of the Iatan 2 plant by the later of August 1, 2005, or such date that KCPL shall issue its request(s) for proposal(s) related to Iatan 2."

III. AGREEMENT

The Signatory Parties agree as follows:

A. DEFINITIONS

As used in this Agreement, the following terms shall have these meanings:

Customer Programs Collaborative (CPC) – a collaborative of Empire and interested non-IOU Signatory Parties that will make decisions pertaining to the development, implementation, monitoring and evaluation of Empire's Affordability, Energy Efficiency and Demand Response Programs (Customer Programs).

Experimental Regulatory Plan – all the terms and conditions contained in this Agreement.

FPPCR – a fuel and purchased power cost recovery mechanism provided for by SB 179.

Iatan 1 – the existing coal-fired electric generation unit located at the Iatan site near Weston, Missouri owned jointly by KCPL, Aquila and Empire.

Iatan 2 – Approximately 800-900 MW of new electric generation capacity to be located at the Iatan site near Weston, Missouri, to be regulated capacity except for any portion owned by a municipality or joint municipal utility commission, approximately 500 MWs of which will be owned by Kansas City Power & Light Company as further defined and described in the Stipulation and Agreement filed with the Commission that initiated the case styled "In the Matter of a Proposed Experimental Regulatory Plan of Kansas City Power & Light Company," Case No. EO-2005-0329.

Regulatory Plan Term/Duration – the approximately five (5) year period beginning with the effective date of a Commission Order that approves this Stipulation and Agreement and ending with the effective date of the initial rates that reflect inclusion of the Iatan 2 investment. Provisions of this Stipulation and Agreement may have a different duration as specified in such provisions.

Resource Plan – A particular combination of demand-side and supply-side resources to be acquired according to a specified schedule over a planning horizon of not less than 20 years.

Resource Acquisition Strategy – A preferred resource plan, an implementation plan and a set of contingency options for responding to events or circumstances that would alter the reasonableness and adequacy of the preferred resource plan.

SCR Equipment at Asbury – an SCR (selective catalytic reduction) environmental retrofit at the Asbury coal-fired base load generating station near Asbury, Missouri.

Significant Change – a change in facts or circumstances that would call into question whether a current course of action is still appropriate.

V84 Combustion Turbine – a Siemens Westinghouse V84.3A2 Econopac gas-fired peaking generating unit to be located at the Riverton generating station in Riverton, Kansas.

B. LIST OF APPENDICES

Appendix A. – Projected Infrastructure Investments and Financing Plan
Appendix B. – In-Service Criteria
Appendix C. – Financial Ratios
Appendix D. – Process Illustration (Amortization)
Appendix E. – Class Cost of Service Data Requirements
Appendix F. – SO2 Emission Allowance Management Policy
Appendix G. - MDNR Targets For Energy Efficiency Programs

C. INFRASTRUCTURE INVESTMENTS AND MONITORING

1. INFRASTRUCTURE INVESTMENT PLAN

Empire agrees to undertake commercially reasonable efforts to make the energy infrastructure investments specified in **Appendix A** and generally described as follows:

- Approximately 800-900 MW of new regulated generation capacity located at the Iatan site near Weston, Missouri, of which Empire anticipates it will own 100-150 MWs (Iatan 2);

- Environmental investments related to Iatan 1 for accelerated compliance with environmental regulations; the Iatan 1 environmental equipment will provide significant reductions in site emissions of SO2, NOx, Particulate and Mercury and will position the unit to meet compliance requirements proposed in the EPA's Clean Air Interstate Rule. With the anticipated addition of Iatan 2 at this site, compliance on Unit 1 will ensure that total site emissions after completion of Iatan 2 will be less than the current site emissions from a single unit and will help address the environmental concerns of citizens living in the area around the Iatan site. With respect to any of the expenditures anticipated for environmental compliance, Empire will continue to assess the environmental laws to ensure that its expenditures will comply with existing or expected environmental regulations.

- A 155 MW gas fired peaking generating unit to be located at the Riverton generating station in Riverton, Kansas (V84 CT).

- An installation of SCR equipment at the Asbury coal fired base load generating station near Asbury, Missouri (SCR Equipment at Asbury). SCR (selective catalytic reduction) equipment reduces nitrogen-oxide emissions.

2. CAPITAL INVESTMENTS IN IATAN 2

Empire agrees to use its best efforts to demonstrate to KCPL that Empire has a commercially feasible financing plan for meeting its financial commitments to participate in the ownership of the Iatan 2 plant by the later of August 1, 2005, or such date that KCPL shall issue its request(s) for proposal(s) for Iatan 2.

3. AGREEMENT CONDITIONED UPON EMPIRE'S PARTICIPATION IN IATAN 2

If Empire does not become a partner with KCPL for an ownership interest in the Iatan 2 plant corresponding to at least 100 MW or approximately 12 percent of capacity, then this Agreement is null and void and of no force or effect for any purpose whatsoever.

4. CERTIFICATE

The Commission granted Empire, in a Report and Order issued on July 28, 1978, in Case No. EM-78-277, a certificate of public convenience and necessity to participate in the construction, ownership, operation, maintenance, removal, replacement, control and management of Iatan Station as a tenant in common. *In the matter of the application of Kansas City Power & Light Company, St. Joseph Light & Power Company and The Empire District Electric Company*, 22 Mo.P.S.C. (N.S.) 249 (1978). The Signatory Parties agree not to assert that further Commission authorization is required regarding Empire's participation in the siting of Iatan 2.

5. CAPITAL INVESTMENTS IN IATAN 1

Empire agrees to fund its ownership percentage of environmental investments related to Iatan 1 for accelerated compliance with environmental regulations. Should Empire sell, assign, transfer, or otherwise dispose of its ownership interest in Iatan 1, the purchaser shall assume all obligations and liabilities associated with Empire's ownership interest in Iatan 1 including, but not limited to, these environmental investments.

6. **<u>ENVIRONMENTAL INVESTMENT RECOVERY TO BE COVERED BY THIS AGREMENT.</u>**

Empire agrees not to propose any environmental rate recovery otherwise allowed to Empire under SB 179 related to the Iatan 1, Iatan 2 and Asbury SCR environmental expenditures covered by this Agreement.

7. **<u>COST RECOVERY OF CAPITAL INVESTMENTS IN IATAN 1, IATAN 2, ASBURY SCR AND V84 CT</u>**

Conditioned on Empire's continued compliance with the terms of this Agreement, and so long as Empire continues to implement its infrastructure investment commitments described herein (or modifications to its infrastructure investment commitments where such modification(s) have been approved by the Commission), the Signatory Parties agree that they will not take the position that the investments identified in Paragraph III.C.1 should be excluded from Empire's rate base on the ground that the projects were not necessary at the time of this agreement, or that Empire should have used alternative technologies. Notwithstanding the preceding sentence, Empire expressly acknowledges that:

1) nothing in this Agreement limits any Signatory Party's right to inquire into the prudence of Empire's expenditures or to assert that an amount different than that proposed by Empire be included in Empire's rate base or its cost of service;

2) nothing in this Agreement limits any Signatory Party's right to propose including in rates an amount that differs from an amount proposed by another Signatory Party; and

3) nothing in this Agreement limits the right of any Signatory Party to challenge Empire's generation investments contained in this Agreement, related costs and off-system sales margins on the ground that Empire failed to acquire more coal-fired resources at an earlier date.

If any party proposes the disallowance of Iatan 1 or Iatan 2 costs, Empire agrees not to seek to avoid such disallowance on the ground that such expenditures were the responsibility of

KCPL and were not within Empire's control. Empire maintains the ability to litigate prudence issues related to these expenditures on any other basis.

8. **IN-SERVICE CRITERIA**

Empire, Staff, Praxair, Explorer and Public Counsel agree that compliance with the in-service criteria for V84 CT and Iatan 2 set out in **Appendix B** satisfies the requirements specified under the Revised Missouri Statutes, of Section 393.135 RSMo. Empire agrees that all units will meet these in-service criteria before being included in rate base. Empire, Staff, Praxair, Explorer and Public Counsel agree that, before the equipment is installed, they will develop and agree to in-service criteria for the emissions equipment that is to be installed on Iatan 1 and Asbury SCR and that that equipment will meet the in-service criteria before the costs for the equipment will be included in Empire's rate base. If Empire, Staff, Praxair, Explorer and Public Counsel are unable to agree, they will present the disagreement to the Commission for resolution.

9. **INFRASTRUCTURE INVESTMENT MONITORING**

Empire shall provide status reports on the Infrastructure Investments identified in Paragraph III.C.1. to the Staff, Public Counsel and other interested non-IOU Signatory Parties on a semiannual basis in conjunction with the IRP meetings described in Paragraph III.F.1. Such reports will explain why these investment decisions are in the public interest. In addition, Empire will continue to work with the Staff, Public Counsel, and other interested non-IOU Signatory Parties in its long-term resource planning efforts to ensure that its current plans and commitments are consistent with the future needs of its customers and the energy needs of the State of Missouri.

Empire agrees to actively monitor the major factors and circumstances that influence the need for and economics of all elements of its Infrastructure Investment Plan identified in

Paragraph III.C.1 until Iatan 2 is placed into service. On its own or upon request of any non-IOU Signatory Party, Empire will reassess the need for and economics of the Infrastructure Investment Plan if changed factors and circumstances arise that may impact the need for and economics of the Infrastructure Investment Plan during the initial and ongoing implementation of the Infrastructure Investment Plan identified in Paragraph III.C.1. Such factors and circumstances would include, but not be limited to:

(i) an act of God;

(ii) terrorist activity;

(iii) a Significant Change in federal or state tax laws;

(iv) a Significant Change in federal utility laws or regulations or a Significant Change in GAAP;

(v) an unexpected, extended outage or shutdown of a major generating unit(s), other than any major generating unit(s) shut down due to an extended outage at the time of the filing of this Agreement;

(vi) a Significant Change in the cost and/or reliability of power generation technologies;

(vii) a Significant Change in fuel prices and wholesale electric market conditions;

(viii) a Significant Change in the cost and/or effectiveness of emission control technologies;

(ix) a Significant Change in the price of emission allowances;

(x) a Significant Change in Empire's load forecast;

(xi) a Significant Change in capital market conditions;

(xii) a Significant Change in the construction costs of elements of the resource plan;

(xiii) a Significant Change in the scope or effective dates of environmental regulations;

(xiv) a Significant Change in federal or state environmental laws;

(xv) a Significant Change in Empire's projected rates and projected costs to ratepayers resulting from Empire's Infrastructure Investment Plan identified in Paragraph III.C.1;

(xvi) a sale of a significant portion of Empire's electric facilities; and,

(xvii) a Significant Change in the assets owned by Empire as the result of an acquisition.

If Empire determines that its Infrastructure Investment Plan should be modified because changed factors or circumstances have impacted the need for and economics of the Infrastructure Investment Plan, then it shall notify all Signatory Parties in writing within ten (10) days of any such determination. In its notification, Empire shall:

1) identify the changed factors and circumstances and explain why they led Empire to propose modification to the Infrastructure Investment Plan;

2) specify the new proposed Infrastructure Investment Plan;

3) provide a description of the alternatives that it evaluated and the process that it went through in choosing the new proposed Infrastructure Investment Plan; and

4) provide detailed workpapers that support the evaluation and the process whereby a new proposed Infrastructure Investment Plan was chosen.

If any Signatory Party has concerns regarding Empire's new proposed Infrastructure Investment Plan, it shall notify Empire and all Signatory Parties in writing within thirty (30) days of Empire's written notification to the Signatory Parties. Upon receipt of any such written notification from a Signatory Party, Empire shall promptly schedule a meeting on reasonable advance notice to all Signatory Parties where the Signatory Parties will make good faith efforts to reach consensus regarding how the Infrastructure Investment Plan should be modified in order to create a modified plan that is reasonable and adequate in light of any changed factors or circumstances. If the Signatory Parties cannot resolve the dispute within ninety (90) days of Empire's written notification, the matter will be brought to the Commission for its determination. Any agreement among the Signatory Parties to modify the Infrastructure Investment Plan shall be filed with the Commission for approval.

If any Signatory Party believes that there have been significant changes in factors or circumstances impacting the need for and economics of the Infrastructure Investment Plan that have not been acknowledged by Empire, any Signatory Party may notify Empire and all other Signatory Parties and request a meeting of all Signatory Parties to discuss the specific changes in factors or circumstances that give rise to the concern of the Signatory Party giving such notice. If the interested Signatory Parties cannot resolve the dispute within ninety (90) days of a Signatory Party's written notification, the matter will be brought to the Commission for its determination. The burden of proof to demonstrate the reasonableness and prudence of any Infrastructure Investment Plan shall remain with Empire in any dispute regarding changed factors or circumstances.

Signatory Parties retain the right to assert, in any proceeding, that Empire did not properly monitor significant factors or circumstances and as a result did not properly execute its Infrastructure Investment Plan.

Nothing in this section shall be construed to interfere with Empire's ability to meet its obligations to provide safe and adequate service by obtaining the resources necessary to meet the short-term reserve margin requirements of Empire's regional reliability organization, currently the Southwest Power Pool, Inc.

D. RATE CASES AND RATE RECOVERY

1. EXPECTED RATE CASES DURING REGULATORY PLAN

Empire is not required to file any rate case prior to the rate case which will include the investments related to the completion of Iatan 2 as described in Paragraph III.D.7 herein.

Any rate case Empire initiates during the term of this agreement shall be subject to the following:

a. NEW SPECIAL CONTRACTS

Empire agrees that for ratemaking determinations, New Special Contracts will be treated as if customers taking service under New Special Contracts were paying the full generally applicable tariff rate for service from Empire. Other provisions in New Special Contracts will not affect rate base for regulatory purposes. For purposes of this Agreement, New Special Contracts are those contracts for service between Empire and a Signatory Party that were not effective at the time of the filing of the Application that began this case.

b. AFFORDABILITY, DEMAND RESPONSE, AND EFFICIENCY PROGRAMS

Any rate case will also include the amortization related to the Affordability, Demand Response, and Efficiency Programs, as more fully described in Paragraph III.F.2 below. The Signatory Parties agree not to contest the continuation of this amortization on any basis other than Empire's failure to prudently implement the Affordability, Demand Response, and Efficiency Programs described in Paragraph III.F.2 below.

c. INTERVENTION IN RATE CASES

Each of the Signatory Parties shall be considered as having sought intervenor status in any rate case or rate filings without the necessity of filing an application to intervene and Empire consents in advance to such interventions. The Signatory Parties expect that the Commission's standard procedures and rules will be applicable to any rate case or rate filing including public notice, local public hearings and evidentiary hearings at appropriate times and places, and an opportunity for interested parties other than the Signatory Parties to seek to intervene.

d. REVENUE COMPUTATION INPUTS

Empire will provide monthly billed kWh sales, rate revenues, customer numbers and billing units aggregated by jurisdiction, by rate class, and by voltage level to Staff and the non-IOU Signatory Parties. This data will be provided by usage period (read cycle) for the weather-sensitive rate classes. Actual data will be provided to the extent available for the test year and additional actual data for the balance of the test year will be submitted as it becomes available.

Empire will provide hourly class load data to Staff and the non-IOU Signatory Parties that covers a minimum of fifteen consecutive calendar months.

2. AMORTIZATIONS TO MAINTAIN FINANCIAL RATIOS

This Agreement contains provisions that provide Empire the opportunity to maintain its debt at investment grade rating during the period of the construction expenditures contained in this Agreement. Empire understands that it is responsible to take prudent and reasonable actions to maintain Empire's debt at investment grade levels and avoid actions that result in a downgrade. Empire further agrees that it will not seek to recover in Missouri jurisdictional rates any negative impact caused by:

1) its failure to be adequately insulated from the business risks of Empire's non-regulated operations;

2) any significant merger, sale or acquisition, or corporate restructuring activities; or

3) its decision to create an additional risk by relying upon the as yet unknown implementation of SB 179 for recovery of fuel and purchased power costs in lieu of addressing recovery of those costs through this regulatory plan.

Empire recognizes its obligation to continue to prudently manage costs, continuously improve productivity, and maintain service quality in a reasonable manner during the Regulatory Plan. Empire further recognizes that any finding by the Commission that Empire has failed to prudently manage its costs, continuously improve productivity, and maintain service quality in a reasonable manner during the Regulatory Plan will negate the obligation of the Signatory Parties contained in this section.

The "Additional Amortizations to Maintain Financial Ratios", is designed to satisfy two of three financial ratio targets shown in **Appendix D** "Process Illustration – Adjustment of Amortization Amount." The three selected financial ratios are: Adjusted Total Debt to Total Capitalization, Adjusted Funds from Operations Interest Coverage and Adjusted Funds from Operations as a Percentage of Average Total Debt. The Adjusted Total Debt to Total Capitalization ratio will be addressed in future Empire financing applications. The current ranges for these financial ratios are shown in **Appendix C** "Financial Ratios." If these ratio guidelines or ranges are changed or modified before June 1, 2010, the Signatory Parties will work together to determine the appropriate values for these ratios, including consideration of the use of the last published ranges for these ratios. In the event that Standard and Poor's changes its ratio guidelines or ranges for these three ratios for a business profile of 6 or Standard and Poor's changes Empire's business profile to a 5 or less, before June 1, 2010, the Signatory Parties will work together to determine if financial ratio targets remain appropriate or whether a change is appropriate. Such determination may include consideration of the last published ranges for these ratios.

The Signatory Parties agree to support an additional amortization amount added to Empire's electric cost of service in any general rate case filed prior to the rate case that includes the Iatan 2 investment when the projected cash flows resulting from Empire's Missouri jurisdictional electric operations, as determined by the Commission, fail to meet or exceed the Missouri electric jurisdictional portion of the financial ratio targets shown in **Appendix D** , for the Adjusted Funds from Operations Interest Coverage ratio and the Adjusted Funds from Operations as a Percentage of Average Total Debt ratio. The Signatory Parties agree to support an amortization level necessary to meet the Missouri jurisdictional portion of these financial ratio targets identified in **Appendix D** and calculated in a manner consistent with **Appendix D**.

Appendix D "Process Illustration: Adjustment of Amortization Amounts" illustrates the adjustment process that the Signatory Parties agree to use to determine the Missouri jurisdictional amortization levels discussed herein. The additional amortization shown in **Appendix D** will exclude any consideration of amounts related to imprudent actions as determined by the Commission. The Missouri electric jurisdictional portion and amounts of the additional amortization will be determined by the Commission in each relevant rate case. The prudence of the "Capitalized Lease Obligations" and "Off-Balance Sheet Obligations" will be determined in the first general rate case or rate filing that affords the Commission the opportunity to review the matter. Additional taxes will be added to the amortization to the extent that the Commission finds such taxes to be appropriate. The additional amortization will not reflect any negative cash flow impacts related to New Special Contracts. For purposes of calculating additional amortization pursuant to this section, these New Special Contract customers will be treated as if they were paying the full generally applicable tariff rate. In addition, any other provisions in New Special Contracts will not affect rate base for regulatory purposes.

The Signatory Parties recognize that credit rating agencies review other financial indicators and other factors and that these three ratios referenced are not definitive in and of themselves. If Empire meets the targets shown in **Appendix D** but does not receive an investment grade credit rating, Empire agrees that the Signatory Parties are under no obligation to recommend or agree to any further cash flow or rate relief. Empire also recognizes and agrees that its Missouri electric operations are only responsible for and will only provide cash flow for its Missouri operating share of the necessary cash flows as set out in this Paragraph III.D.2. Empire will not argue for or receive increased cash flows from its Missouri regulated electric operations needed to meet the financial ratio targets shown in **Appendix D** to the extent caused by:

(1) inadequate cash flows from its non-Missouri retail regulated operations,

(2) inadequate cash flows from any wholesale operations,

(3) inadequate cash flows from the non-regulated subsidiaries,

(4) any risk that is unrelated to Empire's Missouri regulated electric operations,

(5) any Empire imprudent costs, or

(6) any costs not included in Empire's Missouri jurisdictional electric revenue requirement by the Commission.

The Signatory Parties will not be precluded from suggesting other amortizations or other relief to address cash flow concerns resulting from a significant event such as those identified in Paragraph III.C.9.i-iv. No Signatory Party is precluded from supporting an amortization amount that exceeds the requirements of this Paragraph III.D.2. Notwithstanding all of the above provisions in Paragraph III.D.2., the Signatory Parties agree that the amortization amounts in the aggregate shall not exceed the expected cost savings from the amortization mechanism and the lower costs of capital resulting from investment grade ratings.

This paragraph does not preclude a party from requesting that this amortization be directed toward specific plant accounts or from requesting additional changes in depreciation rates that may result from depreciation studies.

3. AMORTIZATION: TEN-YEAR RECOGNITION OF FUTURE BENEFITS

In order to ensure that the benefits of offsetting the rate base related to the amortizations contained in this Agreement accrue to Empire's customers in future rate proceedings, Empire agrees that any such benefits shall be reflected in its rates, notwithstanding any future changes in the statutory provisions contained in Chapters 386 and 393 RSMo, for at least ten (10) years following the effective date of the Order Approving Stipulation and Agreement in this proceeding.

4. ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC")

Empire agrees to a 2.50% or 250 basis point reduction in the equity portion of the AFUDC rate applicable to Iatan 2. Empire shall use this 250 basis point reduction in the AFUDC rate from the effective date of an Order in this proceeding that approves this Stipulation and Agreement, and in all subsequent calculations of AFUDC on Iatan 2 until the in-service date of Iatan 2.

5. CONSTRUCTION ACCOUNTING

The non-Empire Signatory Parties agree to support accounting for the Iatan 2 project, and environmental investments related to Iatan 1, using "Construction Accounting." "Construction Accounting" is defined as use of the same treatment for expenditures and credits consistent with the accounting treatment prior to the time that these investments are placed into service through the effective date of the next succeeding rate case. Construction Accounting will include treatment, if applicable, for test power and its valuation consistent with the treatment of such power prior to Iatan 2's commercial in service operation date. The AFUDC rate that will be used during this period will be consistent with the AFUDC rate calculation prior to the commercial in-service operational date of Iatan 2. The non-IOU Signatory Parties reserve the right to challenge amounts deferred under this paragraph in the event that they contend that the Iatan 2 commercial in-service date was delayed due to imprudence relating to its construction The amortization of the amounts deferred under construction accounting will be treated consistent with the treatment afforded AFUDC.

6. FUEL AND PURCHASED POWER COST RECOVERY

Empire has expressly stated that it intends exclusively to rely upon the FPPCR mechanism of SB 179 for its recovery of fuel and purchased power costs. Accordingly, the Signatory Parties intentionally make no provision for any other fuel and purchased power cost recovery mechanism in this Agreement. However, should SB 179 fail to become law or the FPPCR mechanism be determined by the courts to be unlawful, this provision will not prohibit Empire from proposing an Interim Energy Charge (IEC) for the purposes of fuel recovery in a rate case. The Signatory Parties maintain the right to oppose any IEC proposal.

Empire agrees that, to the extent permitted by law, it will not seek to use the FPPCR provisions of SB 179 for the ratemaking treatment of revenues and costs related to Empire's off-system sales. Empire may propose and support provisions in Commission rules related to SB 179 that provide an option for the inclusion of revenues and costs related to off-system sales in either a Fuel and Purchased Power Cost Recovery mechanism or in base rates (i.e. margin rates). However, Empire will not support, directly or by proxy, a rule provision that only allows the inclusion of revenues and costs related to off-system sales in a Fuel and Purchased Power Cost Recovery mechanism and does not allow their inclusion in base rates.

7. RATE FILING (2009 RATE CASE)

(a) Schedule. Rate schedules will be filed with the Commission on December 1, 2009, or six (6) months prior to the commercial operation date of Iatan 2, whichever is later. With a December 1, 2009 filing, the test year will be based upon a test year ending December 31, 2009, (initially filed with nine months actual and three months budget data), with updates for known and measurable changes, as of March 31, 2010, and with a true-up through June 30, 2010. The specific list of items to be included in true-up proceeding shall be mutually agreed upon between Empire, Staff and Public Counsel, or ordered by the Commission during the course of the rate case.

(b) Empire will provide to Staff and the non-IOU Signatory Parties data as described in Paragraph III.D.1.d. (Revenue Computation Inputs)

(c) Class Cost of Service Study. Empire agrees that its 2009 Rate Case initial filing will include a Missouri jurisdictional customer class cost of service study, covering at least the requirements shown in **Appendix E**, with all underlying workpapers.

E. ADDITIONAL EMPIRE COMMITMENTS

1. SALE OR PURCHASE

In the case of any significant change in the assets owned by Empire as the result of either a proposed sale or acquisition, Empire will file along with its application to the Commission for approval of such sale or acquisition: (a) two resource plans, one with and one without the proposed sale or acquisition; and (b) information designed to affirmatively show that part or all of any amortization resulting from this Agreement would still be necessary after the closing of the proposed sale or acquisition. These filing requirements terminate with the earlier of the date rates become effective as a result of Empire's 2009 rate case (Paragraph III.D.7.) or the end of any amortization contemplated by this Agreement.

If Empire sells, assigns, transfers or otherwise disposes of its ownership interest in Iatan 1, then the purchaser shall assume all obligations and liabilities associated with Empire's ownership interest in Iatan 1 including, but not limited to, the Iatan 1 environmental investments included in Empire's Infrastructure Investment Plan.

2. OFF-SYSTEM SALES

Empire agrees that off-system energy and capacity sales revenues and related costs will continue to be treated above the line for ratemaking purposes. Empire agrees that it will not argue that these revenues and associated expenses should be excluded from the ratemaking process. Nothing in this Agreement prohibits the Signatory Parties from proposing adjustments to normalize or annualize off-system sales or revenues and related expenses in future Empire ratemaking proceedings. Empire agrees that all of its off-system energy and capacity sales revenue will continue to be used to establish Missouri jurisdictional rates as long as the related investments and expenses are considered in the determination of Missouri jurisdictional rates. The phrase "off-system energy and capacity sales revenue will continue to be used to establish Missouri jurisdictional rates" shall mean that such revenues will not be excluded from the ratemaking process so long as "the related investments and expenses are considered in the determination of Missouri jurisdictional rates," regardless of whether that ratemaking process is: (1) a traditional rate case where fuel costs and off system sales revenues are reflected in rates for bundled retail service; or (2) a FPPCR mechanism (such as that enabled by SB 179); (3) an Interim Energy Charge; or (4) some other cost recovery mechanism in which the investments and expenses related to off-system energy and capacity sales revenue are considered in the determination of Missouri jurisdictional rates. Empire agrees that it will not seek to avail itself of any legislation that may be enacted in the future that would be inconsistent with the ratemaking treatment for off-system sales revenues and associated expenses set forth in this paragraph.

3. TRANSMISSION RELATED REVENUES

Empire agrees that transmission related revenues and related expenses will continue to be treated above the line for ratemaking purposes. Empire specifically agrees not to propose any adjustment that would remove any portion of its transmission-related revenues from its revenue requirement determination in any rate case, and Empire agrees that it will not argue that these revenues and associated expenses should be excluded from the ratemaking process. Nothing in this Agreement prohibits the Signatory Parties from proposing adjustments to normalize or annualize transmission-related revenues and related expenses in future Empire ratemaking proceedings. Empire agrees that all of its transmission-related revenues will continue to be used to establish Missouri jurisdictional rates as long as the related investments and expenses are considered in the determination of Missouri jurisdictional rates. The phrase "transmission-related revenues will continue to be used to establish Missouri jurisdictional rates" shall mean that such revenues will not be excluded from the ratemaking process, so long as "the related investments and expenses are considered in the determination of Missouri jurisdictional rates," regardless of whether that ratemaking process is: (1) a traditional rate case where transmission-related revenues are reflected in rates for bundled retail service; or (2) a FPPCR mechanism (such as that enabled by SB 179), (3) an Interim Energy Charge; or (4) some other cost recovery mechanism in which the investments and expenses related to transmission-related revenues are considered in the determination of Missouri jurisdictional rates.

4. PENSION EXPENSE

The Company's FAS 87 cost will be treated in a like manner to that approved by the

Commission in Case No. ER-2004-0570, for all purposes.

5. SO_2 EMISSION ALLOWANCES

The Signatory Parties agree upon the SO2 Emission Allowance Management Policy (SEAMP) contained in **Appendix F**. Empire will record the proceeds, in the event that revenues exceed original cost or the allowance is loaned to a third party, from emission allowance transactions in Account 254, the balance in this account will be Regulatory Liabilities, to be used as an offset to rate base in any future rate case until a final decision is made on the amortization treatment in future rate cases.

6. NON-MISSOURI REGULATORY PLANS CONDITION

If Empire agrees to a regulatory plan related to the construction of Iatan 2 in any of its non-Missouri regulatory jurisdictions and the terms of any such regulatory plan are more favorable to consumers than this Agreement, Empire agrees that it will offer the other Signatory Parties in Missouri comparable terms to those terms agreed upon in such non-Missouri regulatory jurisdiction.

F. RESOURCE PLAN AND CUSTOMER PROGRAMS DEVELOPMENT

1. RESOURCE PLAN DEVELOPMENT

Empire will hold Integrated Resource Planning ("IRP") presentations semiannually and, in addition to making its presentation to the Staff, Public Counsel and the Missouri Department of Natural Resources, will invite to the presentation all interested non-IOU Signatory Parties. To the extent any such party is not required by statute to maintain the confidentiality of the substance of such presentations, the presentations will be subject to a standard confidentiality agreement.

In an effort to reduce Empire's natural gas exposure, the resource plan development process will evaluate purchased power proposals as well as other supply and demand-side resource options and will involve the non-IOU Signatory Parties in an effort to reach agreement on the decisional prudence of at least some of Empire's ultimate resource acquisition decisions.

As an initial step in this process, Empire issued an RFP for up to 200 MW baseload firm capacity and energy on July 1, 2005. Interested non-IOU Signatory Parties will have the opportunity to review the responses at the time they are submitted to Empire. The proposals will be evaluated with the MIDAS CEM (capacity expansion module), the MIDAS Gold integrated resource planning tool and spreadsheet analysis. Global Energy Decisions will assist Empire with the study. Empire will make available to the interested non-IOU Signatory Parties all inputs and outputs from the analytical tools that Empire or its agents use to analyze the proposals as well as all other advice/assistance provided to Empire by Global Energy Decisions.

Empire will submit a detailed resource plan to the non-IOU Signatory Parties in July 2006. The detailed resource planning process shall cover at least a twenty-year planning horizon and the documentation and outcomes of the planning process, at a minimum, shall include:

a) an updated load forecast of seasonal energies and peaks by customer class;

b) identification of changes in the load forecast from its last filing with an explanation of the reasons for the changes;

c) a measurement of the impact on the seasonal demands and energies of all existing energy efficiency and demand response programs, including interruptible and demand curtailment type programs implemented as a result of Commission Case No. EO-2005-0386;

d) identification of projected retirement of existing supply-side resources;

e) identification of candidate demand-side options for purposes of developing alternative resource plans, based upon analysis and recommendations from the

Empire Customer Programs Collaborative (CPC);

f) identification of supply-side resource options including renewable and distributed generation technologies. Empire will issue requests for proposals (RFPs) for supply-side resources that seek to discover potential purchased power agreements (PPAs) and opportunities for participating in new or existing baseload generation as part of its efforts to identify supply-side resource options;

g) ranking of supply-side options based on their relative annualized capital and operating costs with and without probable environmental costs as this term was defined in 4 CSR 240-22.020 (46) at the time of this Agreement;

h) identification of candidate supply-side resource options for purposes of developing alternative resource plans;

i) explanations of eliminations from further consideration of those supply-side options eliminated in a screening analysis;

j) identification of opportunities for life extension and refurbishment of existing generation plants;

k) opportunities for long-term power purchases and sales both firm and nonfirm, that are likely to be available over the planning horizon;

l) transmission upgrade and expansion plans including cost estimates for transmission upgrades associated with each candidate supply-side resource option;

m) sensitivity analysis to identify uncertain factors that are critical to the performance of the resource plan including, but not limited to, load forecast risk, changing fuel prices, and the cost of complying with potential new environmental laws/regulations (including a carbon tax) and other state and federal legislation;

n) combined assumptions for different values of identified critical uncertain factors into internally consistent base case and alternate scenarios (e.g., a carbon tax scenario would likely include higher values for natural gas prices and lower values for coal prices and SO2 allowance prices as coal-fired generation is displaced by gas-fired generation under a carbon tax scenario);

o) development of a set of alternative resource plans which include different combinations of candidate supply and demand-side options. At least one of the alternative resource plans should be designed to minimize long-run costs and/or the risks associated with each of the scenarios. At least one alternative resource plan should be designed to achieve reasonable outcomes for all of the identified scenarios;

p) decision tree analysis (or some alternative analysis agreed upon by the Signatory Parties) of each resource plan that appropriately represents the key resource decisions and critical uncertain factors that affect the performance of the resource plan;

q) a preferred resource plan that, in the judgment of the utility, strikes a balance among all resource planning objectives (including minimization of the present value of revenue requirements over the planning period and the mitigation of risks associated with critical uncertain factors);

r) an evaluation of the risks of the important variables of the preferred plan and the identification of reasonable contingencies to the preferred plan should changes in the expected value(s) of variable(s) cause an alternative plan to become the new preferred plan; and

s) a resource acquisition strategy that includes a three-year implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan.

Empire's submittal shall include a capacity balance table that shows the peak load forecast, taking into account all demand side resources, the generation capacity by unit, contract capacity purchases and sales amounts, planning reserve margin and capacity excess or need, for at least the twenty-year planning horizon.

Within four weeks of its resource plan filing, Empire will meet with the Staff, Public Counsel, MDNR and other interested non-IOU Signatory Parties to present its resource plan and to answer questions regarding the filed plan. If any of the signatory parties identify substantial deficiencies in Empire's attempts to comply with the provisions of this section, the signatory party must provide written notification to Empire within 60 days of the meeting where Empire presented its filed plan. If the parties are unable to resolve a dispute regarding the identified deficiencies within 60 days of the written notification, then the matter may be brought to the Commission for its determination.

Empire will meet semi-annually with the interested non-IOU Signatory Parties beginning within three months of the effective date of this Agreement to update the interested non-IOU Signatory Parties on the progress of its resource planning process. If Empire significantly changes its resource plan or implementation plan between the semiannual meetings, Empire will submit a modified plan within ten (10) days of its decision to change the plan.

Empire will continue to provide to Staff and Public Counsel and other interested non-IOU Signatory Parties copies of competitive bidding RFPs at least 45 days prior to sending out each RFP. Staff, Public Counsel and interested non-IOU Signatory Parties shall have the opportunity to provide comments to Empire within 30 days of their receipt of the RFP.

Thirty days before awarding contracts to successful bidders, Empire will provide to Staff, Public Counsel and interested non-IOU Signatory Parties its evaluation of the proposals received in response to its RFP for its forecasted capacity needs. This evaluation will include the elements of risk analysis and plan selection as described in 4 CSR 240-22.070.

Empire acknowledges Staff and Public Counsel have the right to discovery consistent with Commission rule 4 CSR 240-2.090 regarding any information about Empire's resource planning, and Empire agrees to extend similar rights to non-IOU Signatory Parties with regard to resource planning issues.

The results of Empire's July 2006 Resource Plan will be incorporated into its August 2007 Electric Resource Plan filing. If the Commission's Electric Utility Resource Planning rule (Chapter 22) is revised, the non-IOU Signatory Parties agree to review and revise this section of the Agreement in order to avoid duplicative processes.

If there are issues regarding the resource planning process or plans that the Staff, Public Counsel, interested non-IOU Signatory Parties and Empire cannot resolve, any such party may take the issue(s) to the Commission for resolution.

2. CUSTOMER PROGRAMS COLLABORATIVE -- AFFORDABILITY, ENERGY EFFICIENCY, AND DEMAND RESPONSE PROGRAMS

The Staff, Public Counsel, MDNR, Empire and any other interested non-IOU Signatory Party will serve as a collaborative ("Customer Programs Collaborative" or "CPC") that will make decisions pertaining to the development, implementation, monitoring and evaluation of Empire's Affordability, Energy Efficiency and Demand Response Programs (Customer Programs). The CPC will coordinate its activities with Empire's existing customer programs and

Empire's IRP process in order to reduce any redundancy and to increase the effectiveness of all these related activities. Potential members will state their interest in becoming a member of the CPC by August 1, 2005.

Each CPC member receives one vote. Affirmative votes by a super-majority of the CPC are required in order for the CPC to make decisions in areas 1, 2, 4, 5, and 6 described below. A super-majority is the total number of votes less one. If only one voting CPC member votes against a CPC decision item, that CPC member shall have the opportunity to request that the Commission nullify the CPC's decision on the basis that it is not in the public interest, so long as: (a) the CPC is notified of this pending request within 10 days of the vote; and (b) a pleading is filed with the Commission within 30 days of the vote, requesting that the Commission annul the CPC's decision. No further expense related to the contested decision item will be incurred until the Commission has ruled on this request. If the only CPC member who voted not to affirm a CPC decision item is unsuccessful in its request for the Commission to annul the CPC's decision, that CPC member retains the ability to litigate cost recovery issues, including decisional prudence, pertaining to the unsuccessfully contested CPC decision item.

Empire agrees to meet with and provide updates to the CPC at least once every six months regarding:

1) the status of program implementation including the amount of expenditures for each program and level of customer participation;

2) the status of program evaluations including evaluation consultants chosen, evaluation budgets, evaluation expenditures and copies of completed evaluations; and

3) the status of new program selection and design efforts, including copies of program screening results.

The CPC's oversight of Empire's Customer Programs will include the following areas/activities:

1) Customer Programs Objectives Development. Separate objectives may be developed for Affordability Programs, Energy Efficiency Programs, and Demand Response Programs. Consistent with Empire's current obligations in Case No. ER-2004-0570, the CPC will use its best efforts to identify and implement cost-effective programs that are consistent with the objective of providing the public with energy services that are safe, reliable and efficient, at just and reasonable rates, in a manner that serves the public interest. **Appendix G** identifies the initial targets suggested by DNR. The other Signatory Parties have no reason to believe these targets are or are not valid.

2) Consultant Selection. A consultant(s) will be selected to assist in the design, pre-implementation evaluation, and post-implementation evaluation of Customer Programs.

3) Capacity Balance and Supply-Side Resource Cost Review. A review of Empire's future capacity and energy needs and the supply-side resources that will be required to meet those future needs will take place within three months of the effective date of an Order approving this Agreement. Empire agrees to provide information needed by the CPC for its review of Empire's future capacity and energy needs and the supply-side resources that may/will be utilized to meet those future needs. Information from this review will be used in the pre-implementation cost-effectiveness screening of Customer Programs.

4) Design, Screening, and Pre-implementation Evaluation of Potential Customer Programs. This process will be consistent with the Commission's Chapter 22 Electric Utility Resource Planning Rules. This step will include: (a) the consideration of customer programs that have been shown to be successful and cost-effective by other utilities and (b) DSM screening that includes energy efficiency and demand response programs, including a comprehensive study of interruptible and curtailable opportunities throughout Empire's Missouri service territory.

5) Customer Program Portfolio Choice. A portfolio of Customer Programs to be implemented will be chosen and an implementation plan will be developed. The implementation plan will include a plan for post-implementation process and impact evaluations, where feasible, for each program in the chosen portfolio of Customer Programs. The CPC will seek to develop a full portfolio of Customer Programs, but may decide to move forward with individual programs as they are developed and approved through the CPC decision-making process.

6) Post-implementation Evaluation of Customer Programs. A detailed post-implementation review of the initial two (2) years of each program shall be completed within six (6) months of the end of each program's second year. This review will include both process evaluations and cost effectiveness evaluations. These evaluations will then be used in the selection and design of future programs.

To the extent possible, Empire will coordinate with Missouri Gas Energy (MGE) and other existing entities/organizations to administer its Affordability, Energy Efficiency and

Demand Response programs.

For both the pre-implementation and post-implementation analysis described above, Empire shall use its best efforts to compute, at a minimum, the Total Resource Cost Test, the Utility Cost Test, the Participant Test, the Rate Impact Measure (RIM) Test and MIDAS present value of revenue requirements. The Signatory Parties do not agree that any of these tests are necessarily determinative. Except as stated herein, the CPC's decision-making process will be consistent with the Commission's Chapter 22 Electric Utility Resource Planning Rules. The CPC's documentation of its decision-making process for selecting Energy Efficiency and Demand Response Programs shall identify and explain considerations, if any, other than the minimization of the present value of revenue requirements (e.g., rate impact or risk mitigation considerations) that were used in its decision-making process.

Program evaluation results will be used prospectively for program design and implementation plan adjustments.

The Signatory Parties have not agreed upon any budgeted expenditures for Empire's Customer Programs.

Empire shall accumulate the Affordability, Energy Efficiency and Demand Response Program costs in regulatory asset accounts as the costs are incurred. Beginning with the earlier of the date rates become effective in Empire's first Rate Filing within the term of this Agreement or March 27, 2008, Empire shall begin amortizing the accumulated costs over a ten (10) year period. Empire will continue to place the Affordability, Energy Efficiency and Demand Response Program costs in the regulatory asset accounts, and costs for each vintage subsequent to the first Rate Filing shall be amortized over a ten (10) year period. Signatory Parties reserve the right to establish a fixed amortization amount in any Empire rate case filed prior to June 1,

2011. The amounts accumulated in these regulatory asset accounts that have not been included in rate base shall be allowed to earn a return not greater than Empire's reduced AFUDC rate as specified in this Agreement.

The class allocation of the costs, except as specified below, shall be determined when the amortizations are approved.

Customers on Rate Schedules LP, STS and STS-Praxair will not be charged any costs nor be allocated any expenses with respect to any new energy efficiency and demand response program unless such program has a pre-implementation evaluation RIM test ratio that is greater than 1.0, nor will such customers be eligible for participation in such programs. These customers may be allocated a portion of the costs of screening customer programs when all or part of the amortized costs of such screenings are proposed to be reflected in rates. Praxair and Explorer agree that they will not vote on programs that do not have a pre-implementation evaluation RIM test ratio that is greater than 1.0.

G. EFFECT OF THIS NEGOTIATED SETTLEMENT

1. None of the Signatory Parties shall be deemed to have approved or acquiesced in any question of Commission authority, accounting authority order principle, cost of capital methodology, capital structure, decommissioning methodology, ratemaking principle, valuation methodology, cost of service methodology or determination, depreciation principle or method, rate design methodology, cost allocation, cost recovery, or prudence that may underlie this Agreement, or for which provision is made in this Agreement. This Agreement shall not be construed as fulfilling any requirements for environmental permits necessary for construction or operation of the infrastructure investments delineated in this Agreement.

2. This Agreement is based on the unique circumstances presented by Empire to the Signatory Parties. This Agreement shall not be construed to have precedental impact in any

other Commission proceeding.

3. The Signatory Parties enter into this Agreement in reliance upon information provided to them by Empire. In the event that the Commission finds that Empire failed to provide the Signatory Parties with material and relevant information in its possession, or which should have been available to Empire through reasonable investigation, or in the event that the Commission finds that Empire misrepresented facts relevant to this Agreement, this Agreement shall be terminated.

4. This Agreement represents a negotiated settlement. Except as specified herein, the Signatory Parties to this Agreement shall not be prejudiced, bound by, or in any way affected by the terms of this Agreement: (a) in any future proceeding; (b) in any proceeding currently pending under a separate docket; and/or (c) in this proceeding should the Commission decide not to unconditionally approve this Agreement.

5. The provisions of this Agreement have resulted from negotiations among the Signatory Parties and are interdependent. In the event that the Commission does not approve and adopt the terms of this Agreement in total, it shall be void and no party hereto shall be bound, prejudiced, or in any way affected by any of the agreements or provisions hereof.

6. When approved and adopted by the Commission, this Agreement shall constitute a binding agreement among the Signatory Parties hereto. The Signatory Parties shall cooperate in defending the validity and enforceability of this Agreement and the operation of this Agreement according to its terms.

7. This Agreement does not constitute a contract with the Commission. Acceptance of this Agreement by the Commission shall not be deemed as constituting an agreement on the part of the Commission to forego, during the Regulatory Plan, the use of any discovery,

investigative or other power which the Commission presently has. For example, non-signatories to this Agreement may request or file for an earnings/revenues investigation of Empire, and in response the Commission may direct the Staff to conduct an earnings/revenues investigation of Empire. Nothing in this Agreement is intended to impinge or restrict in any manner the exercise by the Commission of any statutory right, including the right to access information, or any statutory obligation. Nothing in this Agreement is intended to impinge, restrict or limit in any way Public Counsel's discovery powers, including the right to access information and investigate matters related to Empire.

8. This Agreement contains the entire generally applicable agreements or arrangements of the Signatory Parties. There are no other generally applicable agreements or arrangements that pertain to these matters. Silence in this Agreement on a particular topic or issue indicates that the Signatory Parties reached no agreement on the handling of that topic or issue.

9. All of the obligations and conditions Empire agrees to and assumes in this Agreement shall be binding upon any division, affiliate, successor or assignee of Empire in the same manner and to the same extent as Empire.

H. COMMISSION APPROVAL OF THE STIPULATION AND AGREEMENT

1. Empire has filed direct testimony that may be used in support of this Agreement.

2. Public Counsel reserves the right to request local hearings in the Empire service area. Notwithstanding any other provision of this Agreement, Public Counsel also specifically reserves the right to assert a position on any new issue raised at local hearings which has not been addressed in this Agreement.

3. The Staff shall file suggestions or a memorandum in support of this Agreement and the other Signatory Parties shall have the right to file responsive suggestions or prepared

testimony.

4. If requested by the Commission, the Staff shall have the right to submit to the Commission an additional memorandum addressing the matter requested by the Commission. Each party of record shall be served with a copy of any memorandum and shall be entitled to submit to the Commission, within five (5) days of receipt of the Staff's memorandum, a responsive memorandum, which shall also be served on all parties. The contents of any memorandum provided by any Signatory Party are its own and are not acquiesced in or otherwise adopted by the other Signatory Parties to this Agreement, whether or not the Commission approves and adopts this Agreement.

5. The Staff shall also have the right to provide, at any agenda meeting at which this Agreement is noticed to be considered by the Commission, whatever oral explanation the Commission requests, provided that the Staff shall, to the extent reasonably practicable, provide the other parties with advance notice of when the Staff shall respond to the Commission's request for such explanation once such explanation is requested from the Staff. The Staff's oral explanation shall be subject to public disclosure, except to the extent it refers to matters that are privileged or protected from disclosure pursuant to any protective order issued in this case.

6. If the Commission does not unconditionally approve this Agreement without modification, and notwithstanding its provision that it shall become void thereon, neither this Agreement, nor any matters associated with its consideration by the Commission, shall be considered or argued to be a waiver of the rights that any party has to a hearing on the issues presented by the Agreement, for cross-examination, or for a decision in accordance with Section 536.080 RSMo 2000 or Article V, Section 18 of the Missouri Constitution, and the parties shall retain all procedural and due process rights as fully as though this Agreement had not been

presented for approval, and any testimony or exhibits that have been offered or received in support of this Agreement shall thereupon become privileged as reflecting the substantive content of settlement discussions and shall be stricken from and not be considered as part of the administrative or evidentiary record before the Commission for any further purpose whatsoever.

7. In the event the Commission accepts the specific terms of the Agreement, the Signatory Parties waive their respective rights to cross-examine witnesses; their respective rights to present oral argument and written briefs pursuant to Section 536.080.1 RSMo 2000; their respective rights to the reading of the transcript by the Commission pursuant to Section 536.080.2 RSMo 2000; and their respective rights to judicial review pursuant to Section 386.510 RSMo 2000. This waiver applies only to a Commission Order Approving Stipulation and Agreement or other Report And Order approving this Agreement issued in this proceeding, and does not apply to any matters raised in any subsequent Commission proceeding, or any matters not explicitly addressed by this Agreement.

I. THE TERM OF THIS AGREEMENT.

This Agreement (once approved by the Commission) will be deemed to have become effective as of the date the Order of the Commission approving this Agreement becomes effective, and will expire on the effective date of the initial rates that reflect inclusion of the Iatan 2 investment, except where otherwise specified in this Agreement.

J. DISPUTE RESOLUTION.

The Signatory Parties agree that disputes related to the implementation and operation of this Agreement can be taken to the Commission for resolution.

WHEREFORE, the Signatory Parties respectfully request that the Commission approve this Stipulation and Agreement to be effective by August 1, 2005, if possible.

Respectfully submitted,

THE EMPIRE DISTRICT ELECTRIC COMPANY

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CERTIFICATE OF SERVICE

The undersigned certifies that a true and correct copy of the foregoing document was hand-delivered, or sent by electronic mail, on July 6, 2005, to the following:

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STATE OF MISSOURI
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held at its office in Jefferson City on the 24th day of June, 2015.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	**File No. ER-2014-0351** Tracking No. YE-2015-0074

REPORT AND ORDER

Issue Date: June 24, 2015

Effective Date: July 24, 2015

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

In the Matter of The Empire District Electric Company for Authority to File Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area	)))))	**File No. ER-2014-0351** Tracking No. YE-2015-0074

REPORT AND ORDER

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For the Office of the Public Counsel and the Public
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REGULATORY LAW JUDGE: **Kim S. Burton**

The Missouri Public Service Commission, having considered all the competent and substantial evidence upon the whole record, makes the following findings of fact and conclusions of law. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position, or argument of any party does not indicate the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Procedural History

On August 29, 2014, the Empire District Electric Company ("Empire") filed a tariff to increase the general rate for electric service. The submitted tariff would have increased Empire's annual electric revenues by approximately $24.3 million dollars (approximately 5.5%). The tariff (Tracking No. YE-2015-0074) had a September 28, 2014 effective date. The Commission issued an order on September 4, 2014, suspending the tariff until July 26, 2015.[1] The Commission also directed notice be provided to interested parties and set a deadline for applications to intervene. The following parties filed applications to intervene that were granted by the Commission: the Missouri Department of Economic Development—Division of Energy ("DED"); the City of Joplin, Missouri ("Joplin"); Midwest Energy Users' Association ("MEUA");[2] and Midwest Energy Consumers Group ("MECG").[3]

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[1] § 393.150, RSMo 2000 authorizes the Commission to suspend the effective date of proposed tariff sheets for 120 days, plus an additional 6 months to allow for a hearing.

[2] MEUA is an unincorporated ad-hoc association of large commercial and industrial electricity users, with current participants, Explorer Pipeline Company and Enbridge Pipelines (Ozark) L.L.C.

On October 28, 2014, the Commission issued a procedural schedule and set the Test Year to run from May 2013 through April 2014, with an updated test year of August 31, 2014, and a true-up date of December 31, 2014. The Commission conducted three local public hearings; two in Joplin and one in Reeds Spring, Missouri. Consistent with the procedural schedule, the parties filed direct, rebuttal and surrebuttal testimony.

An evidentiary hearing was held on April 14 and April 17, 2015, for the purpose of hearing testimony on the disputed issues. The Commission admitted into the record all pre-filed witness testimony, including exhibits and other attachments.[4] In total, the Commission admitted 98 exhibits into evidence. The Commission cancelled the scheduled true-up hearing upon the request of the parties. The parties filed initial post hearing briefs on May 15, 2015 and reply briefs on May 29, 2015.

General Findings of Fact

1. Empire is a Kansas Corporation with its principal place of business in Joplin, Missouri. Empire is engaged in the business of the manufacture, transmission and distribution of electricity. Empire provides electrical utility services in Missouri, Kansas, Arkansas, and Oklahoma. Empire's service area includes approximately 10,000 square miles in southwest Missouri and the adjacent corners of the three surrounding states.

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[3] MECG is an unincorporated association of large users of electricity provided by Empire. Members of MECG include: Praxair, Inc., General Mills, Walmart Stores, Inc., Sam's Club East, LLC, Jasper Products, LLC, Tyson Foods, Inc., Tamko Building Products, Inc., George's Processing, Inc. and, Simmons Feed Ingredients, Inc.

[4] At hearing, Empire objected to the admission of page 6, lines 1-15 of the Surrebuttal Testimony of MECG's witness Kavita Maini (Exhibit #702). On May 5, the Commission issued a written order overruling Empire's objection and admitting Ms. Maini's Surrebuttal Testimony in its entirety.

Empire is regulated by the utility regulatory commissions in all four states and by the Federal Energy Regulatory Commission ("FERC").[5]

2. Empire mainly serves smaller communities, with the largest city in its service territory—Joplin, Missouri—having a population of approximately 50,000. The company's service territory includes small to medium manufacturing operations, medical, agricultural, entertainment, tourism, and retail interests. In Missouri, Empire serves approximately 125,750 residential customers, 21,463 commercial customers, 276 industrial customers, 1,845 public authority and street and highway customers, and 3 wholesale customers.[6]

3. Empire solely owns and operates four power plants: the Asbury Power Plant, the Riverton Power Plant, the Energy Center Power Plant, and the Ozark Beach Dam and Hydroelectric Plant. Empire also operates and jointly owns the State Line Power Plant.[7]

4. Empire owns 12% of the Iatan Power Station and 7.52% of the Plum Point facility.[8]

5. Empire filed tariffs with the Commission (Tracking No. YE-2015-0074) requesting an overall increase of $24.3 million in Missouri jurisdictional revenue, exclusive of applicable fees or taxes—an increase of 5.5%. Environmental improvement costs at its Asbury generating unit as well as increased Regional Transmission Organization

[5] Exhibit 102, Beecher Direct, pg. 2.

[6] *Id.* at pg. 3. Empire also provides regulated water service in Missouri, and natural gas service through its wholly-owned subsidiary, The Empire District Gas Company. Water and gas rates are not at issue in this case.

[7] Exhibit 112, Mertens Direct, pg. 3. Empire solely owns State Line Unit 1 and jointly owns State Line Combined Cycle with Westar Energy.

[8] *Id.* at 7.

("RTO") charges, and a new maintenance contract for the Riverton 12 generating unit were factors in Empire's request for a rate increase.[9]

6. As part of Empire's plan to comply with EPA standards, Empire installed a scrubber, fabric filter, and power activated carbon injection system at its Asbury plant ("AQCS"). The AQCS improvements at the Asbury plant were completed in December 2014, after the test year. The budgeted costs from the project ranged from $112 million to $130 million.[10]

7. Empire is completing the construction and conversion of Riverton Unit 12 to a combined cycle unit, which should be completed in mid-2016.[11] Empire is expected to file another general rate case within a year to recover what are primarily environmental compliance costs associated with the Riverton Unit 12 improvements.[12]

Conclusions of Law Regarding Jurisdiction

Empire is an electric corporation and public utility, as defined in § 386.020, and is subject to Commission regulations pursuant to Chapters 386 and 393, RSMo.[13] Section 393.140(11) authorizes the Commission to regulate the rates Empire charges its customers. When seeking to increase the rates it charges its customers,

[9] Exhibit 132, Walters Direct, pg. 2-3.

[10] Exhibit 102, Beecher Direct, pg. 4-5.

[11] *Id.* at pg. 6.9

[12] *Id.*

[13] All statutory references are to the 2000 Missouri Revised Statutes, as cumulatively supplemented.

Empire has the burden of proof to show by a preponderance of the evidence that increased rates are just and reasonable.[14]

When evaluating if rates are just and reasonable, the Commission will balance the interests of Empire's investors in making a reasonable return with the interest of the consumers.[15] The Commission is not bound to the use of any single formula when determining just and reasonable rates.[16] It is the results reached, not the method employed which are controlling.[17]

THE ISSUES

I. Revised Agreement

Prior to the evidentiary hearing, Empire, Staff, OPC, Joplin, DED, and MEUA (jointly referred to as, the "Signatories") submitted a joint agreement, *Revised Stipulation and Agreement and List of Issues*, (hereinafter, "Revised Agreement").[18] On that same day, April 8, the Signatories also filed a *Non-Unanimous Stipulation and Agreement on Certain Issues*. MECG filed notice of its non-objection to the Revised Agreement and a separate objection to the *Non-Unanimous Stipulation and Agreement on Certain Issues* ("Position Statement").

[14] Section 393.150. *Bonney v. Environmental Engineering, Inc.*, 224 S.W.3d 109, (Mo.App. 2007).

[15] *Federal* Power *Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[16] State *ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W.2d 870, (Mo.App. W.D. 1985).

[17] *Id.*

[18] On April 3, 2015, the Signatories jointly filed their initial agreement, *Global Stipulation and Agreement*. On April 5, MECG filed its *Objection to Non-Unanimous Stipulation* and its *Notice Regarding Need for Hearing*. The Signatories then filed the Revised Agreement on April 8, 2015, to replace the *Global Stipulation and Agreement*.

The Revised Agreement resolves all but three disputed issues in the following manner:

1. Empire will be authorized to file tariffs designed to increase the company's revenues by $17,125,000 (3.9%), exclusive of any applicable license, occupation, franchise, gross receipts taxes, or similar fees or taxes. It is also agreed that Staff's billing determinants and current revenues, shown in Exhibit B, should be used in the setting of rates in this case.

2. Depreciation of Riverton Unit 7 and Asbury Unit 2 will be discontinued, with Empire directed to use the depreciation rates shown in Exhibit C of the Revised Agreement.

3. Empire will discontinue its Vegetation Management Tracker, with the balance to be trued up in Empire's next general rate case.

4. Empire will discontinue the Iatan 2/Iatan Common/Plum Point O&M Trackers, with the accumulated balances to be trued up in Empire's next general rate case.

5. A Riverton 12 Long-Term Maintenance Tracker shall be established, with the base set at $2.7 million, Missouri jurisdictional. Fluctuations in actual charges above or below this annual level of expense will be recorded in a regulatory asset/liability account. The balance recorded in the regulatory asset/liability account should be amortized over three years, with the revenue requirement associated with this tracker considered during Empire's next Missouri general rate case.

6. Empire will continue its current Energy Efficiency Programs—excepting the low-income weatherization program—at current funding levels and with the current recovery mechanism, until Empire has an approved Pre-Missouri Energy Efficiency

Investment Act ("MEEIA") compliance plan or until the effective date of rates in Empire's next general rate case.

7. Empire will continue its Low-Income Weatherization program, with an annual budget of $225,000. If the budget amount is not spent in any given Empire budget year, the balance will roll over to be spent in a future Empire budget year. Going forward, the low-income weatherization program is not a "demand side measure" or program for purposes of § 393.1075.7.[19] Costs for this program are built into and will be recovered through the agreed-upon revenue requirement.

8. Empire will be authorized to continue its Fuel Adjustment Clause ("FAC") with modifications. Southwest Power Pool ("SPP") Schedule 1A and 12 charges will be excluded from the FAC. Empire's FAC will also exclude Empire's labor, administrative, and convention costs from Acct. 501. For the FAC tariff, the Missouri jurisdictional energy allocation factor will be used in the allocation of off-system sales revenues (accounts 447133 and 447830), and Renewable Energy Credits ("REC") revenues (account 456073). Empire agrees to work with stakeholders to develop descriptions of the costs and revenues flowing through the FAC, to be filed with the Commission in the next general rate case.

9. No changes will be made to the Economic Development Rider.

10. Empire will include the following language regarding Standby Service into its tariffs: "Any 'qualifying facility' as defined in 4 CSR 240-20.060(1)(G) shall be provided, upon request, stand-by power at the otherwise applicable standard rates which would apply if the Company provided energy at the customer's full service requirements."

[19] Unless indicated otherwise, all statutory references are to the Missouri Revised Statutes, as cumulatively supplemented

11. Empire also agrees to work towards submitting a Standby Tariff in its next general rate case that will incorporate concepts agreed to by the parties.[20] Empire also agrees to conduct a standby service cost study before its next general rate case filing, unless the Signatories agree additional time is necessary.

12. The Residential Customer Charge will not be increased in this rate case.

13. Empire will continue the use of a tracker mechanism for pension and OPEB expenses, with the annual level of ongoing Missouri jurisdictional pension and OPEBs expenses at $6,909,482 and $883,144, respectively. The Accounting Standards 715-30 and 715-6- (FAS 87/106) tracker language shall continue in effect. The impact of the expiration of the "substantive plan agreement" amortization on OPEB expenses will continue to be reflected in Empire's ongoing tracker balance calculations.

14. Empire will provide monthly quality of service reporting and will continue submitting monthly revenue and usage reports to Staff. Empire will also continue providing information in its monthly reports, as agreed to in the Non-Unanimous Stipulation and Agreement filed May 12, 2010, in File No. ER-2010-0130).[21]

15. The extension policy proposed by Empire will be implemented.

16. The Commission will adopt Staff's recommended in-service criteria and find the Asbury AQCS to be fully operational and used for service. Any party to Empire's next general rate case may argue the book value of Asbury AQCS. No party is precluded in Empire's next rate case from seeking any disallowance.

17. Empire will make the following total company depreciation reserve adjustments to reflect the unitization of Iatan 2 plant:

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[20] *See* Revised Agreement; pg. 5, ¶15.
[21] *See* Revised Agreement; pg. 6, ¶18.

Account #	Account Description	Depreciation Reserve Adjus
311I2	Structures and Improvements	$101,450.83
312I2	Boiler Plant Equipment	$1,494,664.97
314I2	Turbogenerator Units	$963,628.98
315I2	Accessory Electrical Equip	($281,415.67)
316I2	Misc Power Plant Equip	($2,278,329.11)

18. Empire will make the following adjustments to the additional amortization balances recorded in separate subaccounts in reserves to reflect the unitization of Iatan 2 plant balances:

Account #	Account Description	Depreciation Reserve Adju
311.05	Structures and Improvements	($361,914.88)
312.05	Boiler Plant Equipment	$5,814,553.61
314.05	Turbogenerator Units	$5,401,677.38
315.05	Accessory Electrical Equip	($809,308.39)
316.05	Misc Power Plant Equip	($10,045,007.72)

19. Empire will continue amortization of the DSM regulatory asset for costs incurred during the Regulatory Plan for a total term of 10 years.

20. Empire will continue amortization for the DSM program costs incurred after the end of the Regulatory Plan and prior to any program implementation under MEEIA for a total term of six years.

21. Empire will continue to flow the Southwest Power Administration ("SWPA") payment associated with the capacity restrictions to be implemented for Ozark Beach hydro facility, net of tax, back to the customers over a 10 year period, which began on the effective date of rates in File No. ER-2011-0004, pursuant to a tracker mechanism; for an annual reduction of expense of approximately $1.365 million on a Missouri jurisdictional basis.

22. Empire will refund through rates, beginning with the effective date of rates in this case, the ITC over-collection balance as of December 31, 2014, of $205,593. The refund will be through an amortization over 24 months. Additional over-recovery of the ITC from January 2015 through the effective dates of rates for this case will be reviewed during Empire's next general rate case.

Decision:

Since MECG did not object to the Revised Agreement, pursuant to 4 CSR 240-2.115(2)(C), the Commission may treat it as a unanimous agreement. The Commission is not required to separately state its findings of fact or conclusions of law for those issues disposed of by stipulation and agreement.[22] The evidence admitted into the record is substantial and competent. Based upon the Commission's independent review of the record and the Revised Agreement, the Commission finds that the Revised Agreement is consistent with the public interest and provides Empire with a sufficient

[22] §536.090.

cash flow to provide safe and adequate service. The $17,125,000 (3.9%), increase in Empire's revenues is just and reasonable.

The Commission will authorize Empire to file tariffs in compliance with the Revised Agreement. The Commission will also incorporate the terms of the Revised Agreement into this Report and Order and direct all parties to comply with the terms of the Revised Agreement.

II. Class Cost of Service

a. *How do Empire's residential and industrial rates compare with national averages?*
b. *What, if any, revenue neutral interclass shifts are supported by Class Cost of Service Studies?*
c. *What, if any, revenue neutral interclass shifts should be made in designing the rates resulting from this case?*
d. *What, if any, changes to the Commercial and Industrial customer charges are supported by CCOSS?*
e. *What, if any, changes to the Commercial and Industrial customer charges should be made in designing the rates resulting from this case?*
f. *What, if any, changes to the LP tail block rate are supported by CCOSS?*
g. *What, if any changes to the LP tail block rate should be made in designing the rates from this case?*

Findings of Fact:

8. Under the terms of the Revised Agreement, the parties agreed to an increase in Empire's revenue requirement of approximately 3.9% and no increase in the residential customer charge from its current amount of $12.52.[23] The average bill for an Empire residential customer is $131 per month.[24]

[23] Transcript, Volume 6, pg. 131, ln. 24- pg. 132, ln. 5; Ex. 210, R. Kliethermes Rebuttal, pg. 2.

[24] Transcript, Volume 6, pg. 135, lnb. 10-12.

9. A cost of service analysis provides the revenue requirement necessary for a utility to recover prudently incurred costs of providing service, including a return of and on the capital needed to provide services.[25] If it correctly calculates class cost causation, a cost of service ("CCOS") study can be useful to allocate costs among customer classes and to determine rates that allow a utility a reasonable opportunity to earn the allowed return.[26] A CCOS study approach to rates aims to allocate costs to the causing class.[27]

10. Staff submitted a CCOS study using the Base and Intermediate Peak of analysis method ("BIP"). Staff's CCOS study is based on a test year of May 1, 2013, through April 30, 2014, updated through August 31, 2014.[28] Of the four CCOS studies submitted by the parties, Staff's most reasonably recognizes the relationship between the cost of the plant required to serve various levels of demand and energy requirements and the cost of producing energy.[29]

11. Staff's CCOS recommendation shows that residential rates are 8.06% below costs, while large power ("LP") rates are 8.35% above costs[30] and general power ("GP") rates are 7.9% above costs.[31] All four CCOS studies filed by the

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[25] Exhibit 115, Overcast Direct, pg. 3.
[26] *Id.*
[27] *Id.* at pg. 16.
[28] Ex. 701, Maini Rebuttal, pg. 10. BIP uses three non-weighted components:1) fixed production related costs associated with base load generation that are allocated to classes based on average demand; 2) fixed production related costs associated with intermediate generation that is allocated on the basis of 12CP minus average demand; and, 3) fixed production related costs associated with peaking generation allocated on the basis of 4 CP minus intermediate demand.

[29] Exhibit 204 Staff CCOS Report, pg. 9-11.

[30] Transcript, Volume 6, pg. 107, ln. 6- pg. 108, ln. 13.

[31] Ex. 210, R. Kliethermes Rebuttal, pg. 5; Transcript Volume 6, pg. 122 ln. 14-21. Transcript Volume 6, pg. 107, ln. 4- pg. 108, ln. 13.

parties show that the residential class is contributing below its share of the rate of return.[32]

12. Based on Staff's CCOS results, Signatories to the Position Statement recommend an increase/decrease to the current base retail revenue on a revenue neutral basis to the various classes of customers.[33]

13. "Revenue neutral" means that the revenue shifts among classes do not change the utility's total system revenues. This term is used to compare revenue deficiencies between customer classes and makes it easier to determine the shifts needed between the classes of customers, when appropriate.[34]

14. Shifting customer costs from variable volumetric rates—that a customer can reduce through energy efficiency—to fixed customer charge will reduce incentive efforts to conserve energy.[35] While Staff's CCOS study supports an increase to residential and all other customer charges by the average increase for each applicable class, the Signatories agreed in the Revised Agreement to not increase the residential customer charge.[36]

15. Staff's CCOS study, supported by the Signatories to the Position Statement, recommends the residential service ("RG") class receive a positive 0.75% adjustment

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[32] Transcript, Volume 6, pg. 109, ln. 1- pg. 110, ln. 1. While MECG refers to this discrepancy as a "residential subsidy" the evidence shows that the residential class is currently covering its fixed costs, however, it is not contributing the same level towards Empire's rate of return as other classes.

[33] EFIS Item No. 182, File No. ER-2014-0351.

[34] Exhibit 204, *Staff's* Rate Design and Class Cost of Service Report, pg. 9.

[35] *Id.* at 44.

[36] *Id.* While not one of the Signatories, MECG did not object to the Revised Agreement.

and the total electric billing ("TEB"), GP, and LP classes receive a negative adjustment of approximately 0.85%.[37]

16. After making the revenue neutral interclass adjustments, Staff's CCOS report supports assigning to applicable customer classes the portion of the revenue increase/decrease attributable to the energy efficiency programs from MEEIA program costs. Staff's CCOS results support no retail increase for the feed mill ("PFM") and combined lighting classes as existing revenues received from these classes are providing more revenue to Empire than Empire's cost to serve. After applying these steps, Staff's CCOS Report supports each rate component of each class being increased across-the-board for each class on an equal percentage to recover the $17,125,000 increase in revenue agreed to in the Revised Agreement.[38]

17. The Signatories to the Position Statement recommend a revenue neutral shift that includes a 0.75 %increase for the residential class and a 0.85 %decrease for the LP, TEB, and GP classes.[39] Even though the residential class rates are approximately 8.1% below the class cost of service, the Signatories only recommend a 0.75% increase in the residential rates.[40]

18. Retail rates are pricing signals that drive customer behavior. Empire's average industrial rates are 16% above the national average, while its residential rates are 3.5% below the national average.[41] Based on Staff's CCOS study, the residential class needs an 8.1% revenue neutral adjustment in order to cover the costs incurred to serve the

[37] Exhibit 204, Staff's Rate Design and Class Cost of Service Report, pg. 3.

[38] *Id.*

[39] Transcript Volume 6, pg. 56, ln. 17-23.

[40] Transcript, Volume 6, pg. 135, ln. 2- pg. 136, ln. 3.

[41] Ex. 700, Maini Direct, pg. 4.

class. An adjustment of a 0.75% increase for the residential class, it would take numerous rate cases with similar adjustments over several years for the residential rates to reach cost of service while other classes pay a disproportionate share.[42]

19. Competitive industrial rates are important for the retention and expansion of industries within Empire's service area.[43] If businesses leave Empire's service area, Empire's remaining customers bear the burden of covering the utility's fixed costs with a smaller amount of billing determinants. This may result in increased rates for all of Empire's remaining customers.[44]

20. Attempting to completely eradicate the 8.1% residential rate class discrepancy in this rate case would be too punitive to the customers in that class.[45] A revenue neutral adjustment of 25% of the 8.1% needed adjustment would increase the residential rates by approximately 2%. This 2% increase, in additional to the 3.9% revenue requirement increase, agreed to by the parties in the Revised Agreement, would raise the average residential customer's monthly bill by approximately 5.9%. Since the average monthly bill for an Empire residential customer is $131, this would increase the monthly bill by approximately $7.73 ($131 * 5.9% = $7.73). In comparison, with the .75% revenue neutral increase for the residential class supported by the Signatories in the Joint Position, the average monthly bill for an Empire residential customer would increase by approximately $6.09 ($131 * [3.9% + .75%] = $6.09.

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[42] Exhibit 701, Maini Rebuttal, pg. 14-15.

[43] *Id.* at 14.

[44] *Exhibit 700, Maini Direct, pg.* 14-15.

[45] Exhibit 701, Maini Rebuttal, pg. 14-15.

21. A 2% revenue neutral adjustment for the residential class is not punitive to the residential class and helps to eliminate any residential subsidy in a shorter timeframe.[46]

22. The current tail block rate for the LP class is 0.0363 per kWh in the summer (3.63 cents a kWh) and 3.5 cents a kWh in the summer.[47] Despite MECG's argument to the contrary, the cost of energy for the LP tail block is not below the current tail block rate.[48]

23. Staff's CCOS study supports the Signatories' position that each rate component of each class be increased across the board for each class on an equal percentage basis, including the tail block rates for the LP class.[49]

Conclusions of Law:

Since MECG objected to the Position Statement, it is a nonunanimous stipulation and agreement of those issues it resolves. Pursuant to Commission Rule 4 CSR 240-2.115(2)(D) the Commission will only consider such a stipulation as the position of the Signatories, except that no party is bound by it, and the Commission must still make a determination after hearing of all remaining issues. "Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by

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[46] *Id.*

[47] Transcript, Volume 7, pg 193, ln. 24 – pg. 194, ln. 1-7.

[48] Transcript Volume 6, pg. 57, ln. 15-22.

[49] Transcript, Volume 6, pg. 58, ln. 1-6. Ex. 204, Staff's Rate Design and Class Cost of Service Report, pg. 29.Staff's filed recommendation included an increase to the residential customer charge, however the Signatories agreed in the Revised Agreement to not change the residential customer charge. This excludes the residential customer charge that the parties stated in the Revised Agreement should not be increased. Other portions of the rate element for the residential class will be increased The residential rate schedule consists of the following: 1) residential service rates; 2) customer charge; 3) energy charge-per kWh per season; 4) fuel adjustment – per kWh; and, 5) energy efficiency program charge – per kWh per season.

particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony."[50]

Decision:

Staff's CCOS study supports the position of the Signatories that each rate component for each class be increased across the board for each class on an equal percentage basis.[51] The Signatories also recommend a neutral adjustment recommended by the Signatories (a 0.75% increase for the residential class) to address the recognized 8.1% residential rate class discrepancy. MECG recommends an increase to residential rates by 25% of the needed 8.1% revenue neutral adjustment in order to send a more accurate pricing signal to all of Empire's customers and take a significant step towards moving the residential class closer to its cost of service. The difference between the two is not of such a significant amount as to cause "rate shock." The Commission finds that the increase to residential rates by 25% of the needed 8.1% revenue neutral adjustment is just and reasonable.

Additionally, MECG recommends removing all fixed costs from the second energy block for the LP rate class by adjusting that tail block rate down to coincide with the base costs of fuel. The Signatories oppose this option and instead recommend that each rate component of each class be increased across the board for each class on an

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[50] *State ex rel. Assoc. Natural Gas Co.* v. *Public Service Commission*, 706 S.W. 2d 870, 880 (Mo.App. W.D. 1985). See also *State ex rel. Missouri Office of Public Counsel v. Public Service Comm'n of State*, 293 S.W.3d 63, 80 (Mo. App. 2009)(An administrative agency, as fact finder, also receives deference when choosing between conflicting evidence.)

[51] This is excluding the residential rate class customer charge, for which the Commission is not approving a change, consistent with the terms of the Revised Agreement.

equal percentage basis. The evidence presented by MECG does not support a change in the LP tail block rate.

The Commission finds Staff's CCOS study supports the position of the Signatories to increase each rate component across the board on an equal percentage basis to be just and reasonable.

III. Large Power Rate Design

Should Empire be required to submit a Large Power rate schedule in its next rate case that recognizes a time differentiated facilities demand charge?

Findings of Fact:

24. Empire currently has 38 customers in its LP rate class.[52] Those Customers have demand meters.[53]

25. Empire offers a time differentiated billing demand charge for its special transmission rate classes (SC-P and SC-T), but not for its LP rate class.[54] Time differentiation of the billing demand sends pricing signals that encourage industrial customers to shift their operation away from peak to off-peak periods. By offering a time differentiated billing demand charge for the LP rate schedule, Empire will send the proper capacity price signals regarding transmission and generation infrastructure costs. If members of the LP rate class shift their operations based on capacity price signals, Empire may be able to postpone or cancel future capacity additions.[55]

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[52] Exhibit 204, Staff CCOS Report.

[53] Transcript, Volume 7, pg. 197, ln. 2-4.

[54] Exhibit 702, Maini Surrebuttal, pg. 17-18.

[55] *Id.*

26. Empire may need to manually enter the billing determinants for those customers in the LP class if they are billed on a time-differentiated demand charge, but the amount of this added expense is unknown. Signatories to the Position Statement opposed MECG's request for the submission of a LP rate design in Empire's next general rate case that recognizes a time differentiated demand charge; however, no substantive testimony was offered opposing it.[56]

Conclusions of Law:

The Commission makes no additional conclusions of law.

Decision:

The Commission recognizes the importance of minimizing the collection of fixed costs through the energy charge. Empire opposes the possibility of a large power rate design due to what it asserts are manual tabulation charges to calculate. Empire provided no evidence to demonstrate the unfeasibility of these additional costs, especially if the LP class is to be the class assigned the expense for covering those costs. From a policy perspective, the ability to incentivize members of the LP class to adjust the timing of their use, when possible, will benefit all ratepayers if it postpones or avoids the not insignificant costs of increasing capacity. The Commission will direct Empire to work with Staff and other parties prior to the filing of their next general rate case to

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[56] Transcript, Volume 6, pg. 56, ln. 10-16.

determine the feasibility of an LP rate schedule that will recognize a time differentiated facilities demand charge, including its costs and benefits.

IV. Fuel Adjustment Clause

Should SPP Transmission Costs and Revenues be included? If so, what transmission costs and revenues should be included?

Findings of Fact:

27. An FAC is a mechanism established in a general rate proceeding that allows periodic adjustments, outside a general rate case, to reflect increases and decreases in prudently incurred fuel and purchased power costs.[57] An FAC moves the risk of changes in fuel and transportation costs from the electric utility to that utility's ratepayers. An FAC is a deviation from the usual prohibition against single issue ratemaking.[58]

28. In 2008, the Commission first authorized the use of an FAC by Empire (File No. ER-2008-0093). Since then, the Commission has authorized the continuation, with modifications, of Empire's FAC in three subsequent rate cases.[59]

29. As part of this general rate case, Empire requests that its FAC continue with the current 95 percent/5 percent recovery/return sharing mechanism.[60] Under this FAC sharing level, Empire absorbs (if the energy costs are above the base) or returns (for energy costs below the base) 5% of the over/under balance.[61]

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[57] 4 CSR 240-20.090(1)(c).

[58] Ex. 303, Mantle Direct, pg. 23.

[59] Exhibit 303, Mantle Direct, pg. 5-6. (File Nos. ER-2010-0130, ER-2011-0004, and ER-2012-0345).

[60] Exhibit 303, Mantle Direct, pg. 11.

[61] Exhibit 126, Tarter Rebuttal, pg. 28.

30. Empire currently recovers RTO related transmission costs in base rates that are determined in a rate case test year and annualized for any known and expected changes.[62] Empire is a member of the Southwest Power Pool ("SPP"), an RTO. Empire wants to include in its FAC the net transmission costs and charges from SPP's Integrated Marketplace ("IM").[63]

31. In March 2014, SPP began operating its IM. The SPP IM is an energy market with a day-ahead market, real-time balancing market, and transmission congestion market.[64] Empire is registered in the SPP IM as both a generating and load-serving entity.[65] Empire offers all of its generation into the SPP IM and bids its entire load from the SPP IM. [66]

32. The SPP IM replaced the Energy Imbalance Market ("EIM"). In the SPP IM, Empire's entire native load is supplied from the SPP IM at locational marginal prices. Empire bids in its resources, and if requested by SPP, sells its generation into the SPP IM and receives the revenue. [67]

33. This change in procedure has not made Empire's fuel and purchased power costs more or less subject to Empire's control or predictable.[68]

34. Staff's CCOS study includes purchased power costs and revenues in FERC accounts 555, 565, and 456, which includes purchased power costs as well as costs and revenues from SPP's energy and transmission service markets.[69]

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[62] Exhibit 103, Doll Direct, pg 6.

[63] Ex. 126, Tarter Rebuttal, pg. 2.

[64] *Id.* at 7&10.

[65] Exhibit 103, Doll Direct, pg. 3.

[66] Tr. Volume 7, pg-170, ln. 7-14.

[67] Ex. 126 Tarter Rebuttal, pg 4-5.

[68] Exhibit 305, Mantle Surrebuttal, pg. 3-4.

35. No change in Empire's FAC is required due to the SPP IM. Fuel costs are still accounted for; off-system sales and purchased power can be determined. Transmission costs for off-system sales and true purchased power can be determined.[70]

36. SPP's Schedule 1A transmission rate is designed to recover costs associated with administration of SPP's Open Access Transmission Tariff and is used by SPP for tariff administration. Schedule 12 transmission costs are those costs allocated by SPP on behalf of FERC to recover FERC administration costs for transmission services.[71] SPP Schedule 1-A (Tariff Administration Service) and SPP Schedule 12 (FERC Assessment Charge) are not fluctuating fuel and purchased power costs, but rather, administrative costs.[72]

37. The projected five year SPP related transmission expansion costs are expected to increase, but do not demonstrate volatility.[73]

38. Empire's Missouri jurisdictional RTO transmission costs are reasonably projected and thus not volatile.[74]

Conclusions of Law:

Section 386.266 authorizes the use by an electrical corporation of an interim energy charge or periodic rate adjustment outside of a general rate proceeding to reflect

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[69] Exhibit 204, Staff CCOS Report, pg. 36-37. Staff's report supports the inclusion of SPP Schedules 1,2,7,8,9,10,and 11. Staff' points out that these transmission costs and revenues are, "very similar to the type of transmission costs and revenues that are in the Ameren Missouri FAC tariff sheets." Staff appears to be basing these inclusions on the Commission's Report and Order and Order Approving Compliance Tariff Sheets in Ameren Missouri's general rate case in File No. ER-2012-0166; not the Commission's decision in the most recent Ameren Missouri rate case.
[70] Ex. *305*, Mantle Surrebuttal, pg. 7.

[71] Ex. *105*, Doll Rebuttal, pg. 3-4.

[72] *Id.* at 36-37.
[73] Exhibit 702, Maini Surrebuttal, pg. 3-4.
[74] Ex. 702 Maini Surrebuttal, pg. 4-05.

increases and decreases in prudently incurred fuel and purchased-power costs, including transportation. The statute authorizes the Commission to include features in an FAC designed to provide an electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. This FAC is not a statutory right granted to electric utilities; it is granted based on the Commission's discretion after examination of the expenses.

Under Commission Rule 4 CSR 240-20.090(2), the Commission may approve the establishment, continuation or modification of an FAC and associated rate schedules. In determining what cost components to include in the FAC, the Commission will consider the magnitude of the costs, the ability of the utility to manage the costs, the volatility of the cost components and the incentive provided to the utility as the result of an inclusion or exclusion of a cost component. The Commission is not limited to only those considerations when evaluating a requested FAC. It is within the Commission's discretion to determine what portions of prudently incurred fuel and purchased power costs may be recovered in the FAC and what portion shall be recovered in base rates.

However, Section 386.266.1 provides as follows:

> Subject to the requirements of this section, any electrical corporation may make an application to the commission to approve rate schedules authorizing an interim energy charge or periodic rate adjustments outside of general rate proceedings **to reflect increases and decreases in its prudently incurred fuel and purchased-power costs, including transportation.** The commission may, in accordance with existing law, include in such rate schedules features designed to provide the electrical corporation with incentives to improve the efficiency and cost-effectiveness of its fuel and purchased-power procurement activities. (emphasis added)

The emphasized clause limits the costs that can be flowed through the FAC for recovery between rate cases. It allows for recovery of transportation costs, which has been determined to include transmission costs, but such transmission costs are limited to those connected to purchased power costs.

Decision:

Through approval of the Revised Agreement, the Commission approves the continuing use of an FAC by Empire.

Empire's position is that net fuel and purchased power ("FPP") cost would be the cost to serve native load from the SPP IM, plus the cost of Empire's FPP cost to generate energy for the market, minus revenue received from the SPP IM market sales. Empire's interpretation of "purchased power" under the SPP IM includes the power that Empire generates and then offers through the SPP IM, even if it is used for its native load.

The Commission recently issued a Report and Order in an Ameren Missouri rate case, File No. ER-2014-0258, where it determined it is unlikely the drafters of the FAC envisioned a situation where a utility would consider all its generation either purchased power or off-system sales. In fact, the policy underlying the FAC statute is clear on its face: § 386.266, "...is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power."[75] Nowhere in the record do the facts support a finding that all SPP IM related transmission costs are unexpected and uncontrollable. Furthermore, as has been the case since the FAC statute was created, the costs of transporting energy in addition to the energy generated by the utility or energy in excess of what the utility needs to serve its load are the costs that are

[75] Report and Order, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service (File No. ER-2014-0258)(Issued on April 29, 2015 and Effective on May 12, 2015.) pg. 115.

unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified. Therefore, the costs Empire incurs related to transmission that are appropriate for the FAC, from a policy perspective and by statute, are:

1) Costs to transmit electric power it did not generate to its own load ("true purchased power"); or
2) Costs to transmit excess electric power it is selling to third parties to locations outside of its RTO ("Off-system sales").

Empire argues that the Commission cannot make the same determination that it made in the Ameren Missouri rate case (File No. ER-2014-0258) since the parties did not present factual evidence related to such an argument. Empire is incorrect. The determination the Commission made in Ameren Missouri's rate case was based on its legal analysis of the FAC statutes, and the analysis in that case applies equally to the question of what transmission costs should be included in Empire's FAC. The legal analysis does not change with the facts submitted. .

Empire also argues that, "no party raised the legal issue of whether transmission costs for purchased power should or should not include transmission costs related to self-generated power"[76] and presents this argument as another reason why the Commission cannot make the same determination in this case that it made in the Ameren Missouri rate case. While the exclusion of RTO transmission costs for native load may not have been specifically addressed in the pre-filed testimony in this case, counsel for MECG argued for this position at the evidentiary hearing and in post-hearing

[76] See The Empire District Electric Company's Statement Regarding Transmission Costs and the FAC, pg. 2.

briefs. At the time of the evidentiary hearing in this case, the Commission was beginning to deliberate on the Ameren Missouri rate case. During opening statements at the April 14 evidentiary hearing, MECG's counsel stated, "...we want you, whatever decision you make in the Ameren case, we want it applied to Empire as well. There's an issue in Ameren to disallow transmission costs within the fuel adjustment clause, and we agree with that."[77]

A general rate case is a long process wherein issues are expected to arise that are not always anticipated by the parties at the early stages. Empire's use of an FAC and the costs eligible for recovery through the FAC are issues presented for consideration in this case, and the parties' choice to submit certain legal arguments and not others cannot preclude the Commission from interpreting the law as it determines is most appropriate.

Based on the Commission interpretation of § 386.266, its discretion under the Commission's rules to determine what rates will be recovered in an FAC, and the facts presented, the Commission finds it appropriate to exclude those transmission expenses that do not fall within the two categories described above.

Empire's transmission costs to be included in the FAC are:

1) costs to transmit electric power it did not generate to its own load (true purchased power); and,

2) costs to transmit excess electric power it is selling to third parties to locations outside of SPP (off-system sales).

[77] Tr. Volume 6: pg. 88, ln. 24- pg. 89, ln. 5.

Costs in the FAC will continue to be collected on a per kWh basis. Empire's current FAC 95%/5% recovery/return sharing mechanism will continue.

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by The Empire District Electric Company on August 29, 2014, and assigned Tracking No. YE-2015-0074, are rejected.

2. The *Revised Stipulation and Agreement and List of Issues*, filed on April 8, 2015, is approved and incorporated into this order as if fully set forth herein. The parties shall comply with the terms of the Revised Agreement. A copy of the Revised Agreement is attached to this order as Attachment 1.

3. The Empire District Electric Company is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order no later than July 7, 2015.

4. Before its next general rate proceeding, The Empire District Electric Company shall work with Staff and other interested parties to determine whether implementing a Large Power rate schedule that recognizes a time differentiated facilities demand charge is feasible, and if so, what would be the costs and benefits of doing so for the Commission's consideration.

5. The Empire District Electric Company shall file the information required by § 393.275.1, and Commission Rule 4 CSR 240-10-060 no later than August 14, 2015.

6. This report and order shall become effective on July 24, 2015.

BY THE COMMISSION

Morris L. Woodruff
Secretary

R. Kenny, Chm., Stoll, C., concur;
Hall, and Rupp, CC., concur with separate concurring opinions to follow;
and certify compliance with the
provisions of Section 436.080,RSMo.

Dated at Jefferson City, Missouri,
on this 24th day of June, 2015

Burton, Regulatory Law Judge.