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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2024-0319

SURREBUTTAL TESTIMONY

OF

NICHOLAS L. PHILLIPS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
February 2025

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OF

NICHOLAS L. PHILLIPS

FILE NO. ER-2024-0319

I. INTRODUCTION AND PURPOSE

Q. Please state your name, position and business address.

A. My name is Nicholas L. Phillips, and I am a Director at Atrium Economics, LLC ("Atrium"), a management consulting and financial advisory firm focused on the North American energy industry. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina, 29926.

Q. On whose behalf are you filing testimony?

A. I am filing testimony on behalf of Ameren Missouri ("Ameren Missouri" or "Company").

Q. Are you the same Nicholas L. Phillips that sponsored pre-filed Rebuttal Testimony on behalf of Ameren Missouri in this proceeding?

A. Yes.

Q. What is the purpose of your Surrebuttal Testimony?

A. The primary purpose of my Surrebuttal Testimony is to address the Rebuttal Testimony filed by the Missouri Public Service Commission ("MPSC" or "Commission") Industry Analysis Division Staff ("Staff"). I will also briefly comment on statements made by the Missouri Industrial Energy Consumers ("MIEC") as well as the Midwest Energy Consumers Group ("MECG"). Similar to my pre-filed Rebuttal Testimony, this Surrebuttal

Testimony is narrowly focused and the discussion contained within this testimony is limited. Consequently, no inference should be made with regard to my silence on any position that is not explicitly discussed within this testimony.

Q. Which witnesses' testimonies are you rebutting?

A. My Surrebuttal Testimony largely responds to issues raised in the Rebuttal Testimony provided by Staff witness Sarah L.K. Lange. I briefly address statements made by MIEC witness York as well as MECG witness Maini.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations have not changed since filing my Rebuttal Testimony, namely that the Commission should reject Staff's Class Cost of Service Study ("CCOSS"), and approve rates based on the CCOSS presented by Ameren Missouri.

Q. How is your Surrebuttal Testimony organized?

A. The general topics I respond to are as follows:

1. Staff's analysis of recent renewable resource acquisitions by Ameren Missouri and the approach proposed by Staff to allocate these costs to customers.

2. Staff's analysis and rationale to incorporate wholesale energy prices within the framework used to allocate costs to customers.

3. Staff's analysis regarding the appropriate selection of peaks for use in a demand allocator.

4. Staff's recommendations regarding Classification and Allocation of Distribution System Costs.

5. Positions and recommendations made by MIEC and MECG related to the classification and allocation of production costs.

Q. Are you sponsoring any schedules as part of your Surrebuttal Testimony?

A. Yes, I am sponsoring the following exhibits:

- Schedule NLP-SR1: 1992 NARUC Electric Utility Cost Allocation Manual ("NARUC Manual")
- Schedule NLP-SR2: MPSC Case No. ER-2014-0258 Final Report and Order
- Schedule NLP-SR3: FERC Final Order 668
- Schedule NLP-SR4: MISO Planning Year 2025-2026 Loss of Load Expectation Study Report

Q. Do you have any principal concerns with Staff's positioning regarding the class cost of service paradigm that overlays the specific topics you will discuss throughout your testimony?

A. Yes. Staff appears to believe that the fundamental tenants of regulated class cost of service should be abandoned due to the modernization and clean energy transition of the electric utility system. Of note, Staff characterizes well known and understood concepts such as "fixed" and "variable" as "old worldviews" relegating them as "largely irrelevant to modern utility cost causation."[1] It is undeniable that the electric system is undergoing transformative changes; however, the fundamental components of the system and the associated characteristics remain, as do the economic underpinnings of regulated cost of service. Customers still place demand and energy burdens on the system (though the timing and impact of customer requirements must now also be balanced against a more intermittent and energy limited supply as the penetration of renewable and energy limited

[1] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange, p. 23, ll. 6-8.

resources interconnected to the system increases). In order to reliably serve the demand and energy needs of its customers, utilities still incur both fixed and variable costs (though more and more costs will be fixed as steel in renewable resources replaces fuel costs). What is continuing to change are the types and attributes of resources necessary to provide safe and reliable service to customers while simultaneously being able to support public policy goals such as reduction of carbon emissions, advancing efficiency, etc., and doing so at the lowest reasonable cost. All of which reinforces the need to dutifully analyze the resources and properly functionalize, classify and allocate those resources based on the underlying attributes of the resources. In fact, failure to perform these steps could be viewed as deviating from the principles of cost allocation described by the 1992 NARUC Electic Utility Cost Allocation Manual ("NARUC Manual") which in Missouri, adherence to the principles and methods described in the manual is required by law.

> In determining the allocation of an electrical corporation's total revenue requirement in a general rate case, the commission shall only consider class cost of service study results that allocate the electrical corporation's production plant costs from nuclear and fossil generating units using the ***average and excess method or one of the methods of assignment or allocation contained within the National Association of Regulatory Utility Commissioners 1992 manual or subsequent manual***.[2]

This is important as the Staff does not explicitly discuss the classification of the resources nor is it clear from Staff's workpapers how different costs are classified. The step of classifying costs within an embedded cost study is performed to properly identify which costs are allocated by which allocator. Without this step and indeed a full unbundling of costs through the functionalization, classification and allocation steps of the CCOSS, it is virtually impossible to assess compliance with the statutory requirement.

[2] RSMo. Section 393.1620(2), emphasis added.

Q. Are you questioning whether Staff's proposal complies with the statutory requirement?

A. While I am not an attorney, from my plain reading of the law and understanding of the subject matter, I do question whether Staff's approach complies with the law (though the ultimate determination must be made by the Commission as a threshold issue). There are two reasons for this.

First, the NARUC Manual at page 18, Chapter 2, Section V. "THE COST ALLOCATION PROCESS" describes the steps performed when determining allocation of costs to customers. In particular, Chapter 2, Section V.C. "Allocation of Costs Among Customer Classes" states:

> "***After*** the costs have been functionalized and classified, the next step is to allocate them among the customer classes."[3] [***emphasis added***]

Similar language is used in Chapter 4, "EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS" whereby the chapter discusses how classification is performed as part of the allocation process, noting the NARUC Manual does so in great detail over five pages alone, before delving into specific allocators. From this I do believe that classification is a necessary and indeed fundamental step within the allocation process and further, failure to perform this step can be viewed as deviating from the NARUC Manual's cost allocation process.

Second, while it is possible that one could also infer from a plain reading of the law including its reference to the Average and Excess ("A&E") allocator, (or other methods contained within the NARUC Manual) that the law is narrowly referring to the allocation

[3] Electric Utility Cost Allocation Manual, p. 22, National Association of Regulatory Utility Commissioners, January, 1992.

of production demand related costs specific to Nuclear and Fossil generating units. This is because the A&E allocator is a method for allocating production functional, demand classified costs (i.e., production-demand related costs).[4] In order to trace what costs are allocated with which allocator, it must be possible to trace the respective costs through the various steps. Said another way, one cannot determine if production-demand related costs are allocated using the A&E (or other method) if the study does not identify what costs are both functionalized as production **and** classified as demand related. Staff's approach fails to properly identify the costs in this manner, which hinders the ability to audit compliance; consequently, the approach should be viewed with skepticism from the outset. Complicating the matter even more, Staff's method has discarded the traditional functions of Production, Transmission, Distribution, Customer Service and Facilities, and Administrative and General, and created an entirely new functions Wholesale Energy Cost, Net Market Production and Transmission, Distribution and Metering, and Administrative and Overhead without providing a clear explanation or mapping of how these relate back to the traditional concepts described in the NARUC Manual, further diminishing the ability to assess whether Staff's method complies with the law.[5] Even with this lack of transparency, given that within Staff's approach as partially summarized in Staff's Testimony, Staff discloses that only approximately $440 million of production costs are allocated using the Type I and Type II allocators and the remaining $1 billion is using a price weighted energy allocator.[6,7] Staff defends the use of the Type I and Type II

[4] Id at Chapter 4.
[5] Schedule NLP-SR1 (NARUC Manual) pp.18-19 compared to Direct Testimony of Staff witness Sarah L.K. Lange p. 5.
[6] File No. ER-2024-0319, Direct Testimony of Sarah L.K. Lange p. 19, ll. 2-3, 7-8
[7] I estimated in my Rebuttal Testimony on p. 13, ll. 1-5 that production demand costs were approximately $700 million before the consideration of rate of return ($1.091 billion less $397 is approximately $700 million) as shown in Figure 1.

allocators pointing to the NARUC Manual to justify the uses of the selected allocators and demonstrate compliance with the statute.[8] However, the $440 million allocated using these two allocators is not the entirety of production demand related costs and Staff provides no such justification within the NARUC Manual to allocate the remaining production demand related costs on the basis of price weighted energy – likely because no such method is contained within the NARUC Manual. Given the foregoing, I do not believe that Staff's approach complies with the statutory requirement.

II. RESPONSE TO STAFF POSITION ON THE COST CAUSATION AND ALLOCATION OF RECENT RENEWABLE GENERATION FACILITIES PROCURED BY AMEREN MISSOURI ON BEHALF OF ITS CUSTOMERS

Q. Please summarize Staff's position regarding recent renewable resource acquisitions Ameren made on behalf of its customers and how those costs are allocated to the customer classes.

A. Staff's position, distilled down, is that recent renewable resource acquisitions made by Ameren Missouri on behalf of its customers were caused by an energy need and should therefore be allocated to customers on the basis of energy.[9] Staff discusses multiple renewable projects with the common theme that when the case for a Certificate of Convenience and Necessity ("CCN") was brought to the MPSC to justify the resources, there was a mention of an energy need.[10] However, the fact that there is an energy need does not substantiate that the resource should be allocated entirely on energy.

[8] File No. ER-2024-0319, Direct Testimony of Sarah Sarah L.K. Lange, p. 15, ll. 1-10.
[9] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange p. 7-16.
[10] Id.

Q. Please explain your last statement.

A. Consider the fact that traditional thermal generation assets possessed the ability to provide both capacity and energy to the system. The traditional approach to the classification and allocation of costs essentially decomposed the capital and operating costs of the resource by way of how those costs were incurred, recognizing the fuel and variable operating costs are more closely linked with the energy output of the resource whereas the fixed investments are more closely tied to the capacity of the resource. Renewable generation assets also provide both capacity and energy to the system. However, due to the nature of renewable generation assets such as wind or solar, the amount of capacity that the resource provides varies through the time of day and year, as well as it becomes affected by the amount of other renewable and energy limited resources on the system. Furthermore, renewable energy resources do not incur an operating cost such as fuel (but nevertheless supply energy). Consequently, it may become necessary to think about the individual attributes and use cases of renewable and energy limited resources differently than the traditional approach, but the fundamental characteristics of capacity, energy, fixed and variable costs certainly remain. The analysts should continue to consider these characteristics and apply fundamental economic reasoning when selecting the appropriate way to classify and allocate costs to customers. While many potential alternatives could be considered, suffice it to say, reasonable alternatives would consider both the capacity and energy characteristics of the renewable resources. Further, it may not be unreasonable to seek recovery of energy related portions of renewable resources through a fixed or demand related charge, given these costs do not vary with energy output and would not be avoidable with a reduction in consumption.

Q. How does this relate to Staff's recommended approach regarding the allocation of renewable generation resources?

A. If Staff's approach were carried through in its entirety, one could conclude the counter situation would also hold true, that is, if a resource is added because there is a capacity need, that the entire revenue requirement for that resource should be allocated on a measure of demand. Take for example another resource that Staff discusses later in its testimony, the Castle Bluff simple cycle gas plant.[11] Given the demonstrated need for capacity included in the application for this resource, using Staff's logic, rather than considering the different attributes of the resource, all costs including fuel associated with this resource should be allocated on demand. The reality of prudent utility resource planning is that when a need is identified, regardless of whether the need is capacity, energy or both, all relevant resource characteristics are considered in the evaluation. Of course, in the case of a renewable standard, resource additions must provide the renewable attributes required by the standard, but the planning environment also considers the effective load carrying capability of the resources as a measure of contribution to capacity requirements as well as energy characteristics. The result of such an evaluation is lowest reasonable cost resource(s) to meet both the capacity and energy needs of the system over the planning horizon, as well as meet legislative and regulatory requirements such as renewable energy standards.

[11] File No. EA-2024-0237.

Q. What do you conclude with respect to Staff's recommendation to allocate recent renewable resource additions based on class energy?

A. Staff's approach fails to consider the prudent utility planning process and the actual attributes of the resources. Furthermore, the approach also suffers from a double counting as I described in my Rebuttal Testimony. Namely, there is only one system of generation resources and one set of customer class loads – in order to ensure equitable allocations are performed, it would be incorrect to use the entire class energy profiles to allocate a set of resources unable to meet the total system energy.

Q. Does Ameren Missouri's proposed method for classifying and allocating costs reflect both demand and energy characteristics of the resources?

A. Yes. Ameren Missouri, unlike the Staff, has presented a fully unbundled cost study where the functionalization, classification and allocation steps discussed in the NARUC Manual are fully available. Consistent with the NARUC Manual, Ameren Missouri has classified production plant between demand and energy. The allocator selected for demand classified production costs is the A&E 4NCP allocator. As I discussed in my Rebuttal Testimony, this allocator is what is known as an Energy Weighted allocator in that it considers both customer class peak demands and energy requirements and weights the demand and energy components withing the allocator based on the system load factor.

Q. Are you aware of any utilities who have adopted the use of the A&E allocator because it considers both demand and energy characteristics?

A. Yes. For example, Duke Energy Carolinas ("DEC") convened its stakeholders for a process to examine a change in its allocator for production demand related costs given clean energy legislation passed in the state.[12] While a consensus was not reached among all parties, DEC, the North Carolina Staff, and the Industrial Group reached a settlement that was approved by the North Carolina Commission to move from a 1CP allocator to the A&E allocator precisely because it captures both demand and energy characteristics and many of the fixed cost investments in the system are expected to be related to renewable generation due to the clean energy legislation.[13]

Q. What do you recommend for the allocation of the recent renewable resource acquisitions made by Ameren Missouri on behalf of its customers?

A. I reinforce the recommendation included in my Rebuttal Testimony, namely that the Commission reject Staff's proposal and instead approve Ameren Missouri's proposal for classification and allocation of production plant.

III. RESPONSE TO STAFF POSITION TO INCLUDE WHOLESALE ELECTRIC ENERGY PRICES WITHIN THE DEVELOPMENT OF THE CLASS COST OF SERVICE STUDY

Q. Please discuss Staff's position regarding Wholesale Energy Expenses and Revenues.

A. Similar to Staff's Direct Testimony on the subject, the discussion in its Rebuttal Testimony fails to tell the entire story of how the Staff is using wholesale electric energy prices within its class cost of service study, nor do Staff testimony or workpapers provide sufficient detail regarding the distinction between classifying and allocating costs. Despite this deficiency, the Staff asserts that the Commission has not considered complexities created by Ameren Missouri's (now 20 years of) participation in the MISO

[12] Docket Nos. E-7, Sub 1214 and E-2, Sub 1219.
[13] Docket Nos. E-7, Sub 1276 and E-2 Sub 1300.

energy markets.[14] Staff continues by faulting Ameren Missouri and other parties for failing to consider wholesale energy prices in allocating the cost to serve load and instead relying upon net wholesale costs.[15] Staff concludes that relying upon a study to allocate costs to customers that fails to acknowledge the gross costs and revenues of Ameren Missouri's participation in the MISO market is unreasonable.[16]

Q. Has the Commission previously considered the issue raised by Staff?

A. Yes. In its Final Report and Order in ER-2014-0258 (Schedule NLP-SR2) the Commission found that:

> Furthermore, under FERC Order 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) sale for resale (i.e. off-system sale under account 447 when the utility's cleared generation exceeds the cleared load, or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. That order states "Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load." That means that for accounting purposes, Ameren Missouri is required to recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power.[17]

The Commission further clarified that:

> The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.[18]

[14] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange, p. 17.
[15] Id.
[16] Id.
[17] Schedule NLP-SR2, File No. ER-2014-0258, *Final Report and Order*, p. 113, issued April 29, 2015.
[18] Id at 115.

Q. What was expressed by the FERC in Order 668?

A. The FERC, in Order 668 (Schedule NLP-SR3) stated:

> ***Recording RTO energy market transactions on a net basis is appropriate as purchase and sale transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined. Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load. Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential.*** The Commission will, therefore, adopt the proposed accounting for RTO energy market transactions with certain modifications and clarifications as discussed below. The Commission does expect public utilities, however, to maintain detailed records for auditing purposes of the gross sale and purchase transactions that support the net energy market amounts recorded on their books.
>
> Additionally, we clarify that transactions are to be netted based on the RTO market reporting period in which the transaction takes place. For example, if the RTO market in which the transaction takes place uses an hourly period for determining energy market charges and credits, then non-RTO public utilities purchasing and selling energy in the market must net transactions on an hourly basis. Requiring participants to net transactions over the RTO market's reporting period leads to consistent and comparable energy market information for decision making purposes by the Commission and others.
>
> Further, we clarify that the netting of purchases and sales in an RTO energy market is appropriate not only for transactions where participants are required to bid their generation into the market and buy generation from the market to supply their native load, but also in cases where an RTO offers an energy market in which participants may choose to offer all generation to and buy all power from the energy market.
>
> We also clarify that if a participant is a net seller, rather than a net buyer, during a given market reporting period it must credit such net sales to Account 447, Sales for Resale, instead of Account 555, Purchased Power.
>
> Finally, one purpose of this rule is to establish uniform accounting requirements for the purchase and sale of energy in RTO markets. The purpose of reporting of gross information in EQRs, in contrast, is to provide the Commission and the public

> with a more complete picture of wholesale market activities which affect jurisdictional services and rates, thereby helping to monitor for any market power and to ensure that customers are protected from improper conduct. These are not necessarily the same criteria and principles that should be used in establishing uniform accounting requirements. In any event, the reporting of wholesale market activity in EQRs falls outside the scope of this rule.[19] ***(emphasis added)***

Q. Please discuss the except from FERC Order 668 you emphasized above.

A. It is critical to understand that the "buy all, sell all" aspect of the energy markets does not in and of itself cause changes in *how* the utilities serve native load, nor does it cause new costs or revenues to be incurred. As discussed by the FERC, purchase and sales transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined.

Q. What is meant by "done in contemplation of each other?"

A. For a load serving entity that also owns or contracts for generation resources, if only those owned and contracted resources were used to serve native load (no market purchases or sales) the net wholesale cost will be close to zero. This is because, when the energy market clears, it clears at a single marginal energy cost. The difference between each Locational Marginal Price ("LMP") in a given operating interval is related to the costs for congestion and losses.[20] As a consequence, if the accepted generation volumes in a given hour equal the load purchase volumes for the same hour, the revenues paid to the generators will almost entirely offset the cost of the load purchases.[21] The load

[19] Schedule NLP-SR3, FERC Order No. 668, Paragraphs 80-84 (Pages 39-40).
[20] Locational Marginal Price (LMP) = Marginal Energy Cost (MEC) + Marginal Loss Cost (MLC) + Marginal Congestion Cost (MCC)
[21] The market has additional mechanisms (Financial Transmission Rights ("FTR"), Auction Revenue Rights ("ARR"), etc.) vertically integrated utilities such as Ameren can use to further limit exposure to congestion costs and further tightening the difference between generation revenue and load purchases for service of native load. Though it is worth noting that congestion and losses are not new costs, these have

serving entity then would be incurring the cost of fuel, variable O&M, etc. (including losses and congestion) just as it would have absent the presence of the market. The market does enable a more efficient mechanism to economically dispatch the system when it may be more advantageous for a given participant to back down generation and buy energy from the market or generate additional energy to create off-system sales. These would show up as a difference in net wholesale cost for the given interval and would also coincide with an increase or decrease in fuel expense just as it would have, absent the market.

Q. Would it be reasonable to include gross wholesale costs in the allocation of costs as recommended by the Staff?

A. No. In addition to the discussion in my Rebuttal Testimony demonstrating why the approach leads to illogical results when incorporated into the cost study, the MPSC and the FERC have both already weighed in on why it is appropriate for utilities to net these costs, as done by Ameren Missouri in its cost study. Additionally, as I discussed at the opening of this testimony, there is no clear connection between the NARUC Manual and Staff's proposal as it relates to the use of wholesale energy prices within allocation of costs to customers. Given the law requiring the use of allocation methods aligned with the NARUC Manual, the Commission should consider as a threshold question whether the CCOSS put forth by Staff meets the statutory requirements in Missouri before weighing arguments on the (un)reasonableness of the approach. As I discussed earlier, I do not believe that Staff has met the statutory requirement.

always existed prior to the market and have been included in rates as part of Ameren's cost of service. The MISO market has made these cost components more transparent.

Q. Does the participation in the MISO energy market actually cause new multi-billion-dollar costs and revenues as Staff claims?[22]

A. No. In the last sentence emphasized in FERC Order 668 above, it states that, "Recording these transactions on a gross basis, in contrast, would give an *inaccurate picture of a participant's size and revenue producing potential*." The plain reading of this contradicts Staff's position, i.e. the buy-all, sell-all wholesale energy market transactions, if recorded on a gross basis would actually cause an inflated view of actual costs and revenues rather than, as Staff asserts, be a more accurate reflection wholesale energy transactions. Incorporating this into the CCOSS would thereby distort rather than improve the results.

Q. What do you recommend regarding the use of wholesale energy prices in cost allocation as proposed by Staff?

A. I recommend the Commission reject Staff's proposal and rely on the CCOSS put forth by the Company.

IV. RESPONSE TO STAFF POSITION REGARDING THE SELECTION OF HOURS FOR USE IN THE DEVELOPMENT OF A PRODUCTION DEMAND ALLOCATION METHOD

Q. Staff raises concerns regarding the selection of peak hours for use in a production demand allocator. Please summarize Staff's concerns.

A. At the most basic level, Staff believes that due to Ameren Missouri's participation in the MISO market and its requirement to demonstrate compliance with the MISO's seasonal resource adequacy construct, that the hours used by the MISO in the seasonal resource adequacy construct should be the same hours used to allocate production

[22] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange p. 17, l. 9 to p. 18, l. 8.

demand related costs.[23] Staff also asserts that due to participation in MISO's capacity market, the cost of owning production facilities and maintaining resource adequacy will vary due to energy usage.[24]

Q. Does Ameren Missouri's participation in the MISO capacity market change its obligations for its customers?

A. No. While Staff discusses MISO's resource adequacy construct adopting a seasonal approach (and I will further note that the construct will move to a Direct Loss-of-Load ("DLOL") method for resource accreditation used to demonstrate resource adequacy), these facts are not evidence that all seasons are causing resource investments, nor are clearing prices in the market. The fact is that Ameren Missouri has always been required to provide reliable service throughout the entire year, across all hours and seasons. In order to do so, Ameren Missouri has always been required to evaluate resource adequacy throughout the entire year. The way that Planning Reserve Margins ("PRM") are established, even if a single rather than seasonal PRM is used, is by calibrating a loss of load probability model that considers all hours of the year[25] to a desired reliability metric (MISO uses 0.1 Loss of Load Expectation ["LOLE"]) and determining the amount of perfect capacity needed to meet that requirement. The loss of load risk can occur in many different hours across the year. Relating the amount of perfect capacity back to the system peak, which in the case of MISO or Ameren Missouri is in the summer, provides an annual PRM. This however does not mean that the peak hour is driving risk (and in turn driving

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[23] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange p. 18, l. 17 to p. 23, l. 8.
[24] Id at 23.
[25] MISO used the SERVM model licenses by Astrape Consulting (now a Power Gem company) which actually performs intra-hour analysis. More information can be found in Schedule NLP-SR4 [https://cdn.misoenergy.org/PY 2025-2026 LOLE Study Report662942.pdf](https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report662942.pdf)

investment). But due to the proper calibration of resource capacity accreditation[26] and establishing a PRM, both through a consistent modeling framework based on loss of load probability, does mean that meeting this PRM should then provide enough reliable capacity to meet the requirements of the system throughout all hours of the year. The seasonal construct provides more granularity, especially across such a wide-reaching organization such as MISO. However, the real question is which hours are the loss of load risk hours, as those are the hours that, if there is a capacity need, will drive capacity investment – and the resources installed to meet that need, must be able to provide capacity in those risk hours. For Local Resource Zone ("LRZ") 5 which represents the LRZ that Ameren Missouri is in, as well as MISO as a whole, virtually all LOLE risk still resides in the summer and winter (with winter LOLE of 0.094 out of a total 0.1 across the year for LRZ 5 and summer LOLE of 0.1 for MISO system wide.).[27] It is also worth noting that just because there is LOLE of 0.01 reported in all seasons, does not mean that there is actually LOLE in those seasons, rather seasons that have less than 0.01 LOLE are forced through simulation of adding load to reach a minimum of 0.01 LOLE in order to assess where risk is likely to manifest.[28] Thus, while Ameren Missouri must comply with the seasonal construct, currently its compliance with its summer and winter requirements allows Ameren Missouri to meet compliance with all seasons. There may come a time when this is not the case, but that time is not now. In short, Ameren Missouri will continue to evaluate the appropriateness of the allocation factors used for demand-related production costs in

[26] The DLOL approach for resource accreditation is used to accredit capacity to resource types based on loss of load expectation in the loss of load risk hours.
[27] Schedule NLP-SR4, MISO PY 2025/2026 Loss of Load Expectation Study Report at Table 3-11 https://cdn.misoenergy.org/PY 2025-2026 LOLE Study Report662942.pdf
[28] Id Page 33 at 3.6.1.

future rate proceedings, but it is premature for Staff to conclude that a change is required in this case and furthermore incorrect require that change to be the four MISO seasonal peak hours.

Q. Are you aware of other utilities in MISO that continue to allocate production demand related costs using demand allocators that are not based on the MISO seasonal peaks?

A. Yes. In fact, the vast majority of utilities I am aware of within MISO continue to use allocation methods that pre-date the seasonal construct. As an example, two Indiana utilities, Northern Indiana Public Service Company ("NIPSCo") and Centerpoint Indiana ("CEI") both are in the process of rate cases nearing the conclusion and both are continuing to use four summer coincident peaks to allocate production demand related costs.[29] Other utilities use a variety of other methods that align with the planning of their systems and precedent within their jurisdictions to ensure a level of predictability and stability in rates. NIPSCo and CEI both are continuing to assess their systems and choice of allocators, as all utilities should, to ensure there is a continued alignment of cost allocation with cost causation.

Q. Staff presents an excerpt from Ameren Missouri's CCN filing for the Castle Bluff gas plant discussing MISO capacity auction clearing prices.[30] How does this relate to cost causation?

A. It doesn't. The clearing prices indicate that the LRZ as a whole is getting short on capacity, but if Ameren Missouri owns or contracts for resources able to provide sufficient capacity for its load, then the clearing prices do not increase cost to Ameren

[29] IURC Cause Nos. 46120 and 45990 respectively.
[30] File No. ER-2024-0319, Rebuttal Testimony of Sarah L.K. Lange, p. 21, ll. 4-29.

Missouri. The more important piece of information within the excerpt is largely glossed over by Staff, and that is the statement that the primary need for the plant is winter capacity, which aligns with the MISO LOLE results for LRZ 5.

Q. Does Ameren Missouri's cost of owning production facilities and maintaining resource adequacy vary due to annual energy usage as a result of its participation in the MISO capacity market?

A. No. Staff makes the same erroneous argument here as it does within the context of wholesale energy prices and how Ameren Missouri's participation in the energy market impacts (or doesn't impact) how it serves its native load. Plain and simple, annual energy use does not impact resource adequacy, it is the demand placed on the system during LOLE risk hours. Furthermore, as I discussed earlier as well as in my Rebuttal Testimony, Ameren Missouri plans its system and constructs or contracts for resources to meet its native load obligations. These resources will act as a natural hedge against market prices and the market prices do not cause Ameren Missouri to invest in plant.

Q. Has Staff demonstrated that Ameren Missouri has invested in resources in order to meet spring or fall capacity needs?

A. No. Instead Staff points to a single MISO planning year where prices in LRZ 5 were elevated in the Spring and Fall but not to any investments driven by Ameren Missouri's inability to meet Spring or Fall capacity requirements.

Q. Does Ameren Missouri's proposed A&E 4NCP allocator consider both summer and winter demands?

A. Yes. Both summer and winter excess demands are included for classes that experienced significant summer and winter demands. Not all classes have significant excess demands in all seasons.

V. STAFF'S RECOMMENDATIONS REGARDING THE CLASSIFICATION AND ALLOCATION OF DISTRIBUTION SYSTEM COSTS

Q. Ameren Missouri witness Hickman discusses the classification and allocation of certain distributed production assets, do you have any additional information to discuss on this topic?

A. Yes. In Mr. Hickman's Surrebuttal Testimony, Ameren Missouri agrees with the Staff that some assets recorded in distribution support interconnection of solar facilities to the distribution network and that these assets should be allocated consistent with other production assets.[31] While I agree with Mr. Hickman, I also note that is important to look at the underlying cause for investments in distributed resources and not assume all future resources should be allocated this way. For example, while I was employed at Public Service Company of New Mexico ("PNM"), PNM invested in distributed battery energy storage systems as a means to defer investments in new distribution feeders and relieve hosting capacity constraints on the distribution system.[32] In this way, those resources were justified on the basis of distribution deferrals and in effect operating as distribution alternatives. While I left PNM prior to those costs being brought into rates, in my mind it would be appropriate to functionalize those assets to distribution plant and allocate them consistent with other distribution assets. The same could hold true for future investments on Ameren Missouri's system.

[31] File No. ER-2024-0319, Surrebuttal Testimony of Thomas Hickman, p. 10, ll. 4-20.
[32] NMPRC Case No 23-00162-UT.

Q. Mr. Hickman also responds to Staff's criticism regarding the use of the Handy-Whitman index to place different vintages of embedded costs on the same temporal value for purposes of conducting the Company's Minimum System Study. Do you have any insights to offer on this topic?

A. Yes. In Mr. Hickman's Surrebuttal Testimony, Ameren Missouri disagrees with Staff's criticisms regarding the use of the Handy-Whitman index to adjust book costs of different vintages within the confines of the Minimum System Study ("MSS") used to develop demand and customer classifications for distribution plant.[33] I also disagree with Staff's criticism.

First, I note that the MSS is not used in the development of the Company's revenue requirement nor is it used to restate the Company's rate base balances. It is used to classify the actual embedded costs of distribution plant between customer related and demand related to recognize the dual cost causation drivers of distribution system investments, to connect customers to the Company's distribution system and to ensure sufficient capacity to serve peak load requirements. It is unclear whether the Staff is simply confused as to the use of the MSS or is misconstruing the facts to support its position of a lower customer component of distribution system costs.

Atrium has performed many MSS on behalf of our utility clients and reviewed many other MSS, and with regard to conducting a MSS, indexing installed costs is crucial to ensure that all vintage costs from years of plant account history are evaluated on the same level, that is, on a cost comparative basis. Given the purpose of the MSS is to assess the relationship between the costs of the actual distribution system and the costs of the

[33] File No. ER-2024-0319, Surrebuttal Testimony Thomas Hickman, p.5, ll. 15-23 and p. 6, ll 1-12.

minimum size distribution system, not inflation adjusting the historical costs to current costs would result in an inaccurate depiction of the relationship.

This is discussed in industry literature, for example: The Electric Utility Cost Allocation Manual, by John J. Doran, et. al., provides the following discussion of the zero-intercept method in Chapter VI B., "Two Methods for Determining Customer Components of Distribution Facilities:"

> "The minimum-intercept methods described in this chapter are based on average installed book cost of plant items. Because of inflation, which is generally reflected in larger size equipment, a rational minimum intercept cost may not be obtained where desired. ***However, the use of reproduction costs for each size will eliminate the distortion caused by inflation.*** A trend factor must then be used to reduce the minimum intercept from reproduction cost to average book value level. When data for its calculation can be obtained, the minimum-intercept method is recommended for use over the minimum-size method."[34] ***[emphasis added]***

Another example in literature is within the Regulatory Assistance Project ("RAP") Electric Cost Allocation for a New Era. In my Rebuttal Testimony I discussed concerns with this publication. However, while I maintain those concerns and I do not recommend the methods contained within this publication, in the section of this publication discussing MSS (albeit in an attempt to dissuade the use of MSS), it correctly states:

> "The minimum system method attempts to calculate the cost ***(in constant dollars)*** if the utility's installed units (transformers, poles, feet of conductors, etc.) were each the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks: How much would it have cost to install the same number of units (poles, feet of conductors, transformers) but with the size of the units installed limited to the

[34] Electric Utility Cost Allocation Manual, John L. Doran, Frederick M. Hoppe, Robert Koger, William W. Lindsay, published by the National Association of Regulatory Commissioners (1973), page 56. This text was later given attribution by the head of the task force assembled by the NARUC Staff Subcommittees on Electricity and Economics in February 1985, to compile revisions and additions to the original manual. Among the objectives included in the Preface of the manual published by NARUC in 1992 was the following: "The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons." [emphasis added]

> current minimum unit normally installed? This minimum system cost is then designated as customer-related, and the remaining system cost is designated as demand-related. The ratio of the costs of the minimum system to the actual system ***(in the same year's dollars)*** produces a percentage of plant that is claimed to be customer-related."[35]***[emphasis added]***

The use of the Handy-Whitman Index[36] serves this purpose by adjusting historical costs to reflect current market conditions. It tracks changes in construction, labor, and material costs across time and regions. By applying the index, utilities can trend historical costs to their current value, providing a more accurate representation of the cost to reproduce or replace the system today. This ensures that the minimum system study reflects the economic realities of operating an electric utility in the present when determining which portion of the embedded costs should be classified as customer related and which portion should be classified as demand related.

VI. DISCUSSION OF POSITIONS AND RECOMMENDATIONS REGARDING THE CLASSIFICATION AND ALLOCATION OF PRODUCTION COSTS TAKEN BY MIEC AND MECG

Q. Did other parties take issue with Staff's recommended approach related to allocating production costs?

A. Yes. Both MIEC and MECG filed testimony disagreeing with Staff's recommendation and both parties recommend the A&E 4NCP allocation proposed by Ameren. While both parties have their own discussions, many of the same foundational arguments and reasoning contained within my rebuttal are also voiced by these parties. It is also worth noting that MIEC also raises similar concerns to those raised in my Rebuttal

[35] Regulatory Assistance Project ("RAP") Electric Cost Allocation for a New Era at Page 146.
[36] The Handy-Whitman Index of Public Utility Construction Costs is published semi-annually on January 1 and July 1 of each year by Whitman, Requardt and Associates is a widely recognized economic indicator that tracks the costs associated with building and upgrading public utility infrastructure.

testimony related to Staff's proposed method for classifying and allocating distribution costs and specifically raises the issue of double counting billing units associated with direct assignment.

Q. Do both MIEC and MECG support the classification and allocation methods used for distribution and production costs proposed by Ameren?

A. Yes.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes.

ELECTRIC UTILITY
COST ALLOCATION MANUAL

January, 1992

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS

1101 Vermont Avenue NW
Washington, D.C. 20005
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PREFACE

This project was jointly assigned to the NARUC Staff Subcommittees on Electricity and Economics in February, 1985. Jack Doran, at the California PUC had led a task force in 1969 that wrote the original **Cost Allocation Manual**; the famous "Green Book". I was asked to put together a task force to revise it and include a Marginal Cost section.

I knew little about the subject and was not sure what I was getting into so I asked Jack how he had gone about drafting the first book. "Oh" he said, "There wasn't much to it. We each wrote a chapter and then exchanged them and rewrote them." What Jack did not tell me was that like most NARUC projects, the work was done after five o'clock and on weekends because the regular work always takes precedence. It is a good thing we did not realize how big a task we were tackling or we might never have started.

There was great interest in the project so when I asked for volunteers, I got plenty. We split into two working groups; embedded cost and marginal cost. Joe Jenkins from the Florida PSC headed up the Embedded Cost Working Group and Sarah Voll from the New Hampshire PUC took the Marginal Cost Working Group. We followed Jack's suggestions but, right from the beginning, we realized that once the chapters were technically correct, we would need a single editor to cast them all "into one hand" as Joe Jenkins put it. Steven Mintz from the Department of Energy volunteered for this task and has devoted tremendous effort to polishing the book into the final product you hold in your hands. Victoria Jow at the California PUC took Steven's final draft and desktop published the entire document using Ventura Publisher.

We set the following objectives for the manual:

- It should be simple enough to be used as a primer on the subject for new employees yet offer enough substance for experienced witnesses.
- It must be comprehensive yet fit in one volume.
- The writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

It is with extreme gratitude that I acknowledge the energy and dedication contributed by the following task force members over the last five years.

Steven Mintz, Department of Energy, Editor; Joe Jenkins, Florida PSC, Leader, Embedded Cost Working Group; Sarah Voll, New Hampshire PUC, Leader, Marginal Cost Working Group; Victoria Jow, California PUC; John A. Anderson, ELCON; Jess Galura, Sacramento MUD; Chris Danforth, California PUC; Alfred Escamilla, Southern California Edison; Byron Harris, West Virginia CAD; Steve Houle, Texas Utility Electric Co.; Kevin Kelly, formally NRRI; Larry Klapow California PUC; Jim Ketter P.E., Missouri PSC; Ed Lucero, Price Waterhouse; J. Robert Malko, Utah State University; George McCluskey, New Hampshire PUC; Marge Meeter, Florida PSC; Gordon Murdock, The FERC; Dennis Nightingale, North Carolina UC; John Orecchio, The FERC; Carl Silsbee, Southern California Edison; Ben Turner, North Carolina UC; Dr. George Parkins, Colorado PUC; Warren Wendling, Colorado PUC; Schef Wright, formally Florida PSC; **IN MEMORIAL** Bob Kennedy Jr., Arkansas PSC.

Julian Ajello
California PUC

SECTION I

TERMINOLOGY AND PRINCIPLES OF COST ALLOCATION

SECTION I of the Cost Allocation Manual provides three chapters to familiarize the reader with the terminology and principles of cost of service studies and cost allocation theory.

Chapter 1 describes the nature of the electric utility industry in the United States. It provides a brief history of the industry, a description of the physical characteristics of the plant whose costs must be allocated and a discussion of the institutional structure of the industry.

Chapter 2 provides an overview of cost of service studies and summarizes the cost allocation process. It discusses the role played by cost of service studies in ratemaking and the development of the two major types of cost studies: embedded and marginal. It briefly outlines three issues of particular interest: treatment of joint and common costs, time differentiation and future costs and notes how the two types of studies deal with those issues. Finally, it describes the cost allocation process that is common to both types of studies.

Chapter 3 reviews the development of the utility's revenue requirement, including the concepts of a test year and the determination of the utility's rate base, rate of return and operating expenses.

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CHAPTER 1

THE NATURE OF THE ELECTRIC UTILITY INDUSTRY IN THE U.S.

In order to understand the process of allocating the costs of electric utilities to their customers, it is helpful to review the industry in the context of how it developed, and its current physical and institutional characteristics. This first chapter will therefore provide a capsule history of the American electric utility industry. It will then address the physical characteristics of the industry, including generation, transmission and distribution, and review the concepts of energy and capacity. Finally, it will discuss the institutional structure of the industry, both the types of utility organizations and the levels of jurisdiction that regulate them.

I. CAPSULE HISTORY

The founder of the American electric utility industry was Thomas A. Edison. While not the originator of either electricity or lighting -- Sir Humphrey Davy invented the arc light in 1808, Michael Faraday introduced the dynamo in 1831, and a host of inventors had experimented with such technologies as arc lights for illumination, the telegraph, phonograph and telephone -- it was Edison who first developed the concept of a central station and system of delivery which could provide the energy for light, heat and power. In 1882, Edison opened the Pearl Street Station in New York City serving 85 customers with 400 lamps.

The early years of the electric industry were characterized by competition. Edison's efforts to create and finance central electric power stations were in competition with gas lighting companies and isolated power plants. Westinghouse Electric developed a new approach which, in contrast to Edison's direct current (DC) that could be transmitted for only a few miles, relied on an alternating current (AC) produced at 1000 volts, which could be transmitted over long distances and then transformed to 50 or 100 volts. Thus, it became possible to develop central generating plants located at hydroelectric or coal mining sites with transmission across long distances to load centers. At the local level, cities granted multiple, sometimes competing, franchises to companies providing either type of current for individual purposes (street lighting, domestic lighting, tramways, commercial power).

The electric industry grew rapidly during the last 20 years of the 19th century, multiplying the number of companies, pushing out from the urban centers to the surrounding rural areas, improving plant and transmission to achieve economies of scale, and expanding electrical uses beyond lighting. The number of independent systems declined as companies amalgamated to rationalize franchises, achieve load diversity and forestall competition. Financing for the capital intensive industry evolved into long term general mortgage bonds whose financiers required assurances that the longevity of the companies would equal the length of the bonds. Industry leaders like Samuel Insull of Chicago Edison began to seek the protection of state sponsored regulation as security against short-lived city franchises.

While operating companies became regulated by state commissions after 1900, holding companies remained unregulated. The original holding companies resulted from engineering and equipment firms receiving securities rather than cash for their goods, investment bankers taking over utilities they had financed, and consolidation to achieve operating efficiencies. By the 1920's, however, the holding company movement had become a mania, fueled in most part by the large profits gained by the promoters. In 1932, 73 percent of investor owned utilities nationwide were controlled by eight companies: Insull's company, for example, operated in 32 states and controlled assets of over half a billion dollars. The financial abuses of the holding companies led first to their investigation by the Federal Trade Commission in 1928, their partial collapse in the stock market crash of 1929 and the onset of the Great Depression, and finally their dismemberment under the Public Utility Holding Company Act of 1935.

The 1930's also saw the growth of public power. Municipal ownership had been a feature of the industry from its inception, with the municipals exceeding investor owned utilities in number, although not in either customers or capacity, through the mid-1920's. The Roosevelt Administration's promotion of such projects as the Boulder Dam and the sale of inexpensive federal power to publicly owned distribution companies encouraged many municipalities to take over their local distribution companies. Meanwhile, projects like the Tennessee Valley Authority and the Bonneville Power Administration and the financing of farmer cooperatives by the Rural Electrification Administration brought publicly owned electricity to the hitherto unserved rural populace.

The two decades following the Second World War are characterized by declining prices, due primarily to increased efficiencies in generation. Average plant size increased five-fold, and the heat rate (BTUs of energy required per kilowatt hour of electricity) and the cost of incremental generating plant per kilowatt both declined by 37 percent over the twenty year period. Financing for the capital investment was considered to be relatively risk-free and was therefore achieved at minimal cost. As a result, the price of electricity fell by 9 percent (compared to an increase in the Consumer Price Index of 75 percent). Usage per residential customer increased 155 percent and the amount of self-generation declined from 18 percent of total generation in 1945 to 8.8 percent in 1965.

Between 1965 and 1970, electricity prices remained stable and usage continued to increase although costs of construction, financing and operation began to rise. By the 1970's, utilities realized that the increasing cost of production was not a temporary phenomenon and began to reflect increased costs in rates. Production facilities that had been planned in a period of low inflation, constant demand growth and concern over reserve margins stemming from the 1965 Northeast blackout, were built in an era of high inflation, and increased construction and financing costs, and finally achieved commercial operation in an age of uncertain demand and competitive alternatives to utility generation. By the mid-1980's, all forms of generation appeared under attack: hydro-electric by advocates of alternate uses of rivers, nuclear because of concerns over cost and safety, and fossil fuel by environmentalists pointing to problems of air pollution, acid rain and the greenhouse effect. The bankruptcy of Public Service Company of New Hampshire in February 1988 owing to its investment in the Seabrook Nuclear Power Station is an extreme example of an electric utility industry unable to meet its obligations to both its customers for electrical generation and its creditors for the capital to finance it. Its problems were not unique, however, as its demise had been foreshadowed by the omission by Consolidated Edison of its common stock dividend in 1974, and Cincinnati G&E's cancellation of the 97 percent complete Zimmer plant and the default of the Washington Public Power Supply System on its bonds in 1983. Utilities began to turn to new options, on both the demand and supply side of the equation, to satisfy their markets' requirements for the energy services of light, motor power and heat.

II. PHYSICAL CHARACTERISTICS OF THE ELECTRICAL INDUSTRY

In the electric utility industry, power is produced by the utility company at central generating stations, transmitted over high voltage power lines to the load centers within its franchise area or to other points of delivery, and finally distributed at lower voltages to the ultimate customers. Those three components, generation, transmission and distribution, comprise the basic elements of the physical structure of the electric utility industry. First, however, a crucial concept in the planning, operation, and costing of the industry is understanding the difference between capacity and usage, or kilowatts and kilowatt-hours.

A. Kilowatts and Kilowatt-hours

Key to analyzing any electric utility cost of service study is an understanding of the difference between kilowatts (KW) and kilowatt-hours (KWH). In terms of physics, KWH equates to work and KW equates to power, where work is defined as force times the distance through which it acts, and power is defined as the work done per unit of time.

In the electric industry, work is termed energy; power is termed capacity or capability in discussions of generating plants, and demand in discussions of customer usage.

The basic unit in electricity is the watt, most familiar as the rating on light bulbs and appliances. A 100 watt bulb burning constantly for an hour would use 100 watt-hours of electricity. Thus, watts are a measure of capacity while watt-hours add the dimension of the time period during which the capacity is used. Since the watt is a very small unit of measurement (746 watts equal 1 horsepower), consumer bills are measured in kilowatt-hours (thousands of watt hours) and utility system generation is reported in megawatt-hours (millions of watt hours).

B. Generation

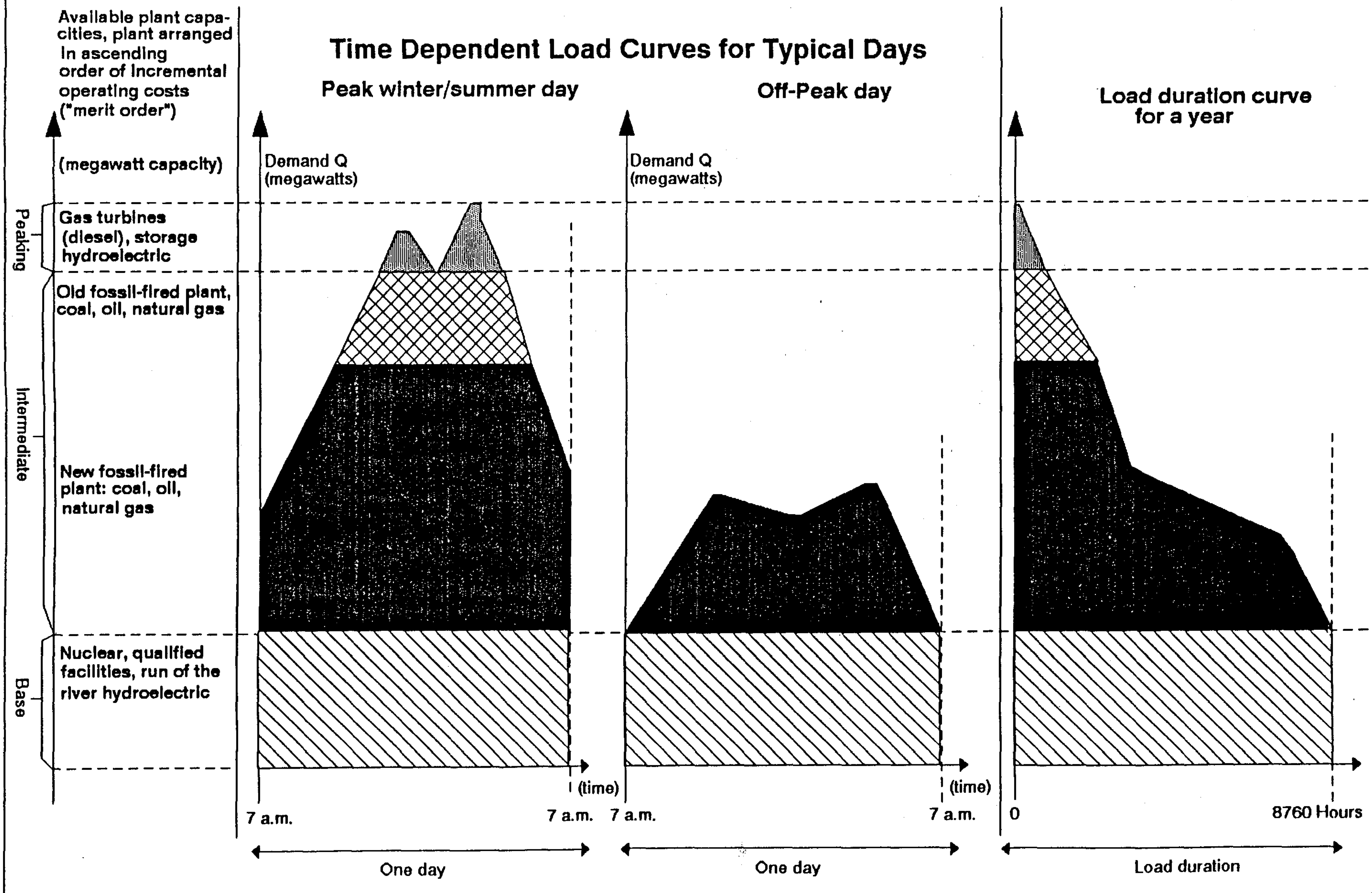
The demand for power on an electric system varies with time, with variations occurring for any given utility in a fairly predictable pattern during the hours of a day and the seasons of a year (see Figure 1-1). A graph that plots hours of the day against demand on the system will typically show low usage during the night hours, which rises to one or more peaks during the day hours as customers turn on their machinery (and heat or cool), and then gradually falls during the late evening hours. Similarly, the graph of a utility's annual demand will typically demonstrate the lower demand on the system in the spring and fall with greater usage exhibited in the winter and/or summer reflecting electric heat and air conditioning loads.

Such time differentiated graphs can be translated into load duration curves in which demand, rather than plotted against hours of the day or days of the year, is plotted against the number of hours of the year (up to all 8760) during which any particular level of demand occurs. The shape of the load duration curve over the year in large measure determines the utility planner's choice of generating plant needed to satisfy customer demand. The challenge to the system planner is to provide sufficient generating capacity to satisfy the peak demand, while recognizing that much of that plant will not be needed for a large part of the day and year. As different types of generating units are marked by different operational and cost characteristics, the utility will attempt to build the types of units that provide it with the flexibility to match supply to demand for every hour at the lowest possible cost.

Utilities generate most power by burning fossil fuels (coal, oil and natural gas), employing nuclear technology, and running hydro-electric plants. In addition, they purchase power both from other utilities and from independent power producers whose facilities may include run-of-the-river hydro-electric, wood, municipal solid waste, wind, geothermal, tidal, or electricity cogenerated with some form of heat used in district heating or in a manufacturing process.

The utility system operators load (dispatch) and unload generating stations sequentially in order of operating costs as demand rises and falls on the system. Base load

FIGURE 1-1
LOAD DISPATCHING



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plants are constructed to meet the utility's minimum demand by operating continually throughout the day and year. They cannot be loaded and unloaded easily, either because of their operating characteristics (for example, nuclear) or because of contractual or legal requirements (purchases from small power producers or run-of-the-river hydro-electric). They tend to have high fixed costs that can and must be spread over many hours of the year, and lower operating (primarily fuel) costs. At the other extreme, peaking plants are constructed to satisfy the demand that may occur only for a few hours of the year. These plants must be easily loaded and unloaded onto the system and, since the hours of their operation are limited, must have low capital costs. Generally, they also have high fuel costs (e.g., gas turbines) although hydro-electric stations with some reservoir capacity may also be constructed as peakers because of the ease of instantaneous operation. Intermediate plants, fossil fuel stations burning coal, oil and natural gas, are dispatched less frequently than base load and more often than peakers. Dispatch of particular stations will vary according to relative fuel costs: in periods of particularly low oil prices, for example, oil-fired stations may operate as baseload rather than intermediate plants.

In recent years it has become apparent that utilities have the option of influencing their demand curves as well as varying their sources of supply. Thus, a utility with base load capacity but a rising peak demand may be able to shift some of its peak load to off-peak hours, to make better use of its base load facilities, rather than building additional peaking units.

C. Transmission

A utility's transmission system consists of highly integrated bulk power supply facilities, high voltage power lines and substations that transport power from the point of origin (either its own generation or delivery points from other utilities) to load centers (either in its own franchise territory or for delivery to other utilities). The transmission function is generally concluded at the high voltage side of a distribution substation owned by the utility or at points where the ownership of bulk power supply facilities changes.

In general, the transmission system is comprised of four types of subsystems that operate together. The backbone and inter-tie transmission facilities are the network of high voltage facilities through which a utility's major production sources, both on and off its system, are integrated. Generation step-up facilities are the substations through which power is transformed from a utility's generation voltages to its various transmission voltages. Subtransmission plant encompasses those lower voltage facilities on some utilities' systems whose function is to transfer electric energy from convenient points on a utility's backbone system to its distribution system. Radial transmission facilities are those that are not networked with other transmission lines but are used to serve specific loads directly.

The two principal characteristics that distinguish one transmission system from another are the voltages at which the bulk power supply facilities are designed and operated and the way in which those facilities are configured. Voltages can and do vary widely from one electric system to another. For example, where one system's predominant backbone transmission facilities may consist of 345 kilovolts (KV) or higher, another's may consist of only 115 KV, while still another may have a combination of facilities that operate at various voltages. Utilities also configure their transmission systems differently. Some are highly integrated, where facilities of the same or different voltages form networks that provide a number of alternative paths through which power may flow. Other systems may be essentially radial, with few or no alternative paths.

D. Distribution

The distribution facilities connect the customer with the transmission grid to provide the customer with access to the electrical power that has been generated and transmitted. The distribution plant includes substations, primary and secondary conductors, poles and line transformers that are jointly used and in the public right of way, as well as the services, meters and installations that are on the customer's own premises.

Typically, transmission and distribution plant is separated by large power transformers located in a substation. The substation power transformer "steps down" the voltage to a level that is more practical to install on and under city streets. Distribution substations usually have two or more circuits that radiate from the power transformer like spokes on a wheel, hence the expression, "radial distribution circuits". These circuits will often tie to each other for operating convenience and emergency service, but under normal operation an open switch keeps them electrically separate. Thus, in contrast to the transmission system where a change of load at any point on the system will result in a change in load on the entire system, a change in load on one part of the distribution system will not normally affect load on any other part of the distribution system.

Distribution circuits are divided into primary and secondary voltages with the primary voltages usually ranging between 35 KV and 4 KV and the secondary below 4 KV. Primary distribution voltages run between the power transformer in the substation and the smaller line transformers at the points of service. Advances in equipment and cable technology permit using the higher voltages for new installation. Since the ability to carry power in an electrical conductor is proportional to the square of the voltage, these higher primary voltages allow a reasonably sized conductor to carry power to more customers at greater distances.

Manufacturing standards for industrial electrical equipment, lighting, and appliances specify voltages at 480 volts or less. Therefore, at customer locations along the primary distribution circuit a smaller line transformer is installed to further reduce the voltage to the secondary level. Large industrial customers may install their own line transformers and take service at primary voltage. The utility may choose to install a transformer sized to the load and dedicated to exclusive use of other commercial and industrial customers. In high density customer areas such as housing tracts, a line transformer will be installed to serve many customers and secondary voltage lines will run from pole to pole. At each customer premise a line (service drop) is tapped off the secondary line directly to the customer's meter.

III. INSTITUTIONAL CHARACTERISTICS OF THE ELECTRIC INDUSTRY

The electric industry is a public utility, a term that denotes the special importance of the service it provides ("affected with the public interest") and its inherent technical characteristics that lead to ineffective competition ("natural monopoly"). The latter feature has been strongly associated with economies of scale and decreasing unit costs of production. While increasing economies of scale are no longer clearly evident in generation, the inefficiencies of duplicating transmission and distribution facilities, for reasons of both economics and aesthetics, remain. In the absence of competition to moderate prices in the naturally monopolistic electric industry, public policy has adopted three institutional forms of restraint: cooperatives, municipals, and regulated investor-owned utilities. It should be noted that under some state statutes the term "public" is also used to specifically denote public ownership (cooperatives and municipals).

A. Utility Organizations

In cooperative electric utilities, the ratepayers and owners are the same. Most investment capital is provided through loans, usually from the Rural Electrification Agency, and prices are set so that revenue covers costs of operation including debt service. The ratepayers/owners hire professional managers to operate the utility and, while they may vote on their retention at annual meetings, neither the managers nor the cooperative's officers are often voted out of office.

A municipal electric utility is operated by the political unit it serves, with its professional managers appointed by the elected officials. The municipality may furnish the necessary capital for the utility plant either through taxes or indebtedness, and utility rates can be set either to cover costs including debt service as separate enterprise funds, or to interact with other municipal finances. In the latter case, the municipality may chose either to subsidize utility services from tax sources or to generate profits to enhance fire, police and other municipal services. A variation on municipal utilities are the federally operated multi-state authorities like the Tennessee Valley Authority or the Bonneville Power Authority.

Investor-owned utilities (IOU's) are privately owned corporations whose investment capital is furnished by a combination of indebtedness and stockholder provided equity. Where prices in cooperatives are restrained by the owner/ratepayers, and in municipals by the voters/ratepayers, the directors of the IOU's are subject to no such constraints. Their primary goal is the long-term maximization of return to the stockholders, a goal that is by no means inconsistent with the goal of public policy that utilities provide safe and reliable service at just and reasonable rates. Consistency between private and public ends is assured, however, through governmental regulation of the IOU's.

All utilities share an interest in protecting their exclusive right to serve their franchised service territory because of the opportunities to increase profits and/or reduce unit costs through economies of scale. Only IOU's pay federal income taxes; state and local taxation depends on the controlling laws in the service areas where the different types of utilities operate. All IOU's are publicly regulated; regulation of cooperatives depends on the laws of the particular jurisdiction; municipals are often regulated only for service provided outside their municipal boundaries.

B. Regulative Jurisdictions

Public utility regulation in its present form is the end result of considerable experimentation and adjustments to changing conditions. Experimentation in the techniques of regulation has resulted over the decades in today's administrative commissions, a distinctly American contribution to government control of business.

The right to regulate stems from the United States Constitution. State regulation is based on the residual authority known generally as "state police powers", designed to protect the health, safety and general welfare of citizens. Utilities operating in interstate commerce, either because they operate in multi-state jurisdictions or sell in wholesale inter-utility transactions, are subject to control by federal agencies. A utility that operates in both inter- and intrastate commerce will be regulated by both federal and state jurisdictions and any lack of consistency between the two regulatory bodies can lead to over-collection or under-collection of revenue by the utility.

State commissions are charged with setting just and reasonable rates, in both level and design, and assuring safe and reliable service. In addition, state commissions grant utilities authority to engage in various forms of financing and they control the delineation of service territories. The extent of commission authority in each of these areas varies somewhat from state to state, depending on statutory language and judicial interpretation.

With some specific exceptions, all of investor-owned utilities wholesale (sales for resale) operations are under the control of the Federal Energy Regulatory Commission (FERC), formerly the Federal Power Commission (FPC). The statutory duties of the FERC are comparable to those of the state agencies. The Federal Power Act of 1935 vested the FPC with the authority to regulate the interstate sales of electric power. With the passage of this Act, the FPC and its successor the FERC, has authority over:

- The disposition, merger, or consolidation of facilities and the acquisition of the securities of another utility.
- The issuance of securities.
- The rates and services of the companies under its jurisdiction.
- Accounting and depreciation practices.
- The holding of certain interlocking positions in different companies by the same person.

For the most part, FERC rate and service regulations affect wholesale rates. Thus, FERC ratemaking policies, especially in regard to rate design, can have a significant impact on the intrastate systems that purchase electric power from a FERC-regulated investor-owned utility.

CHAPTER 2

OVERVIEW OF COST OF SERVICE STUDIES AND COST ALLOCATION

This chapter presents an overview of cost of service studies and cost allocation theory. It first introduces the role of cost of service studies in the regulatory process. Next, it summarizes the theory and methodologies of cost studies, with a comparison of accounting-based (embedded) cost methodologies and marginal cost methodologies. Finally, it introduces and briefly discusses the three major steps in the cost allocation process: the "functionalization" of investments and expenses, cost "classification", and the "allocation" of costs among customer classes.

I. COST OF SERVICE STUDIES IN THE REGULATORY PROCESS

Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary criterion for the reasonableness of rates.

The cost principle applies not only to the overall level of rates, but to the rates set for individual services, classes of customers, and segments of the utility's business. Cost studies are therefore used by regulators for the following purposes:

- To attribute costs to different categories of customers based on how those customers cause costs to be incurred.
- To determine how costs will be recovered from customers within each customer class.
- To calculate costs of individual types of service based on the costs each service requires the utility to expend.
- To determine the revenue requirement for the monopoly services offered by a utility operating in both monopoly and competitive markets.

- To separate costs between different regulatory jurisdictions.

Generically, the prime purpose of cost of service studies is to aid in the design of rates. The development of rates for a utility may be divided into four basic steps:

- Development of the test period total utility revenue requirement - The total revenue requirement is the level of revenue to be collected from all sources. This subject will be addressed in detail in Chapter 3.

- Calculation of the test period revenue requirement to be recovered through rates - This is simply the total revenue requirement of the utility from all sources less the amount from sources other than rates.

- The cost allocation procedure - The total revenue requirement of the utility is attributed to the various classes of customers in a fashion that reflects the cost of providing utility services to each class. The cost allocation process consists of three major parts: functionalization of costs, classification of costs, and allocation of costs among customer classes.

- Design of rates - Regulators design rates, the prices charged to customer classes, using the costs incurred by each class as a major determinant. Other non-cost attributes considered by regulators in designing rates include revenue-related considerations of effectiveness in yielding total revenue requirements, revenue stability for the company and rate continuity for the customer, as well as such practical criteria as simplicity and public acceptance.

II. THEORY AND METHODOLOGIES

Historically, regulation concerned itself with the overall level of a company's revenues and earnings and left the design of rates to the discretion of the utility. To the extent that utility managements justified their rate structures on cost, rather than rationales of value of service or "what the market will bear", they defined cost in engineering and accounting terms. Utilities developed cost studies that were based on monies actually spent (embedded) for plant and operating expenses and divided those costs (fully allocated or distributed them) among the classes of customers according to principles of cost causation. The task for the analyst was to allocate, among customers, the costs identified in the test year for which the revenue requirement had been calculated.

Through the years, the industry and its regulators have witnessed a gradual evolution of the concepts for allocation. Since generating units and transmission lines are sized according to the peak demand consumed, the individual contribution to peak demand came to be considered the appropriate factor for the allocation of the costs of those facilities. Costs incurred to supply energy such as fuel were rationalized to be allocatable by usage. Costs that vary by the number of customers and not their consumption were allocated by customer. While subsequent analysis has complicated the assignment of particular costs to various categories, cost allocation has generally evolved into three cost classifications: demand, energy and customer.

By the 1970's, the economic environment had changed for the electric utilities. In the new era of general inflation, high energy and construction costs, and competition, rates based on pre-inflationary historical costs led to poor price signals for customers, inefficient uses of resources for society, and repeated revenue deficiencies for the companies. Regulators and utilities began to inquire whether the principles of marginal cost were the appropriate reference for regulated utility rate structures in the United States. Such concepts had long been the theoretical economic framework for the analysis of competitive markets, and since the 1950's, the basis of utility rates in England and France.

Marginal cost theory is derived from the neo-classical economics of the nineteenth century which states that in a perfectly competitive equilibrium, the amount consumers are willing to pay for the last unit of a good or service, equals the cost of producing the last unit, i.e., its marginal cost. As a result, the amount customers are willing to pay for a good equals the value of the resources required to produce it, and society achieves the optimal level of output for any particular good or service. In a competitive market, this equilibrium is achieved as each firm expands its output until its marginal cost equals the price established by the forces of supply and demand. For the utility monopoly, the regulator attempts to achieve the same allocative efficiency by accepting the level of service demanded by customers (the utility's obligation to serve) as the given, and setting price (or rates) equal to the utility's marginal cost for that level of output. The analyst defines the cost as the change in cost due to the production of one unit more or less of the product, and various approaches have been advanced to measure the utility's marginal cost.

A deficiency of the marginal approach for ratemaking purposes is that marginal cost-based prices will yield the utility's allowed revenue requirement based on embedded costs only by rare coincidence. Since regulatory agencies are bound not to let the utility over-earn or under-earn, revenues from rates must be reconciled to the allowed revenue requirement. As the rates are reconciled to the revenue reqirements and prices diverge from marginal cost, the sought after marginal cost price signals may not be obtained. When prices do not exactly equal marginal cost there is no formal proof that the economic efficiency predicted by theory is achieved. Advocates of marginal cost pricing believe that approximations to marginal cost pricing must contribute to efficient resource allocation, although to an unspecifiable degree. Supporters of embedded cost pricing believe that the greater precision, verifiability and general simplicity of embedded cost methods outweigh any of the hoped for efficiency benefits of imperfect approximations to marginal cost pricing. This problem and various proposed solutions are addressed in Chapter 10.

It is important to note that the difference between an embedded cost of service study and a marginal cost of service study lies in their different concepts of cost. The embedded cost study uses the accounting costs on the company's books during the test year as the basis for the study. In contrast, the marginal cost study estimates the resource costs of the utility in providing the last unit of production. Once "cost" is determined, the procedures for allocating cost among services, jurisdictions and customers are largely the same. Thus, the practical and theoretical debates in marginal cost studies tend to center around the development of costs, while the debates in embedded cost studies focus on how the cost taken directly from the company's books should be divided among customers.

III. EMBEDDED AND MARGINAL COST STUDY ISSUES

There are three subjects of particular interest in the development of cost studies: treatment of joint and common costs, time-differentiation of rates, and incorporation of future costs. The following discussion will briefly address how the two types of studies deal with those issues.

A. Joint and Common Costs

Joint costs occur when the provision of one service is an automatic by-product of the production of another service. Common costs are incurred when an entity produces several services using the same facilities or inputs. The classic example of joint costs are beef and hides where it is not possible to allocate separate costs of raising cattle to the individual product. In the electric industry, the most common occurrence of joint costs is the time jointness of the costs of production where the capacity installed to serve peak demands is also available to serve demands at other times of the day or year. Overhead expenses such as the president's salary or the accounting and legal expenses are examples of costs that are common to all of the separate services offered by the utility.

In an embedded cost study the joint and common costs identified in the test year are allocated either on the basis of the overall ratios of those costs that have been directly assigned, or by a series of allocators that best reflect cost causation principles such as labor, wages or plant ratios, or by a detailed analysis of each account to determine beneficiality. The classification and treatment of the joint and common costs requires considerable judgment in an embedded cost study. (See Chapters 4 through 8 for a more detailed discussion).

In a marginal cost study, the variation of those common costs that vary with production is incorporated into the study through regression techniques and becomes a multiplier to the marginal cost per kilowatt or kilowatt-hour. There are fewer joint and common costs in marginal cost studies than in embedded because many of the common costs do not vary with changes in production. The presence of joint and common costs, both variable and non-variable, contributes to the inequality between the totals obtained from a marginal cost study and the revenue requirement based on the embedded test year costs.

B. Time Differentiation of Rates

Most time differentiation of rates stems from the recognition that costs vary by time. It is a popular misconception that time differentiated rates are a unique feature of marginal cost studies. To the contrary, both embedded and marginal cost studies can be designed to recognize cost variations by time period. It is true that marginal cost studies are designed to calculate the energy and capacity costs attributable to operating the last (marginal) unit of production during every hour of the year. The hours can then be grouped into peak, off-peak and shoulder periods for costing and pricing purposes. However, in embedded studies, the baseload, intermediate and peak periods can be identified, and different configurations of production plants and their associated energy costs, can be assigned to each period. (See Chapter 4.) Thus, the primary difference between the two types of studies in regard to the calculation of time differentiated rates is that the costs fall naturally out of a marginal cost study while embedded cost analysts are required to perform a separate costing step before allocating costs to the customer classes.

C. Future Costs

In most cost studies submitted to regulatory commissions, the accounting costs in embedded cost studies reflect the cost incurred in providing a given level of service over some time period in the past. Optimally, the utility's cost study and test year for revenue requirement purposes will be based on the most recent twelve months for which data are available, although regulators are often faced with the difficulties of stale test years. To the extent that the price of inputs, technology, and managerial and technical efficiency cause the cost of providing service in the past to differ from the cost of service in the future, rates based on historic test years will over- or under-collect during the years the rates are in effect. Within the context of embedded studies, solutions to the need to incorporate future costs include recognition of known and measurable changes to the test year costs, step increases between rate cases, fuel adjustment mechanisms to give immediate recognition to variations in fuel costs and the use of a forward-looking test year for the cost study. This last is the most comprehensive response to the need to reflect future costs within an embedded study. However, it has the disadvantage of relying on estimated costs rather than costs that are subject to verification and audit. Thus, in the eyes of many regulators, an embedded study based on a future test year loses one of the prime advantages it has over marginal cost studies.

In contrast to the standard embedded cost study, marginal costs by definition, are future costs. Marginal cost studies estimate either the short-run marginal costs, in which plant, equipment and organizational skills are fixed, but labor, materials and supplies can be varied to satisfy the change in production, or the long-run marginal costs, in which all inputs including production capacity can be adjusted. As a matter of practicality, marginal cost studies usually adopt an intermediate period tied to the planning horizon of the utility.

IV. SOURCES OF DATA

While the data for cost studies are generally provided by the utility company, the documents that are relevant depends on the type of cost study being performed. Embedded cost studies rely on the company's historical records or projections of these records, whose accuracy can be audited and verified either at the time of filing or at the end of the period projected. Marginal cost studies use the company's planning documents.

A. Data for Embedded Cost Studies

Where a cost of service study is made in conjunction with a rate case proceeding, the costs that are distributed to the various classes of service should be the costs used in determining the utility's overall revenue requirement. The principal items of historical information required to develop cost allocations based on accounting costs are plant investment data, including detailed property records, balance sheets, information on operating expenses and on performance of generating units, load research (information on KWH consumption and the patterns of that consumption) and system maps. These costs are contained in the books and records maintained by the company, and are proformed to recognize known and measurable changes. The utility files projected revenues, investment and costs for all accounts in cost studies using projected test years.

Electric utilities generally are required by law to keep their records according to the Uniform System of Accounts (USOA) as prescribed by the Federal Energy Regulatory Commission in the Code of Federal Regulations CFR Title 18, Subchapter C, Part 101. This code sets the guidelines for booking assets, liabilities, incomes and expenses into each account. Major categories of costs are listed as follows:

100 Series	Assets and other debits
200 Series	Liabilities and other credits
300 Series	Electric plant accounts
400 Series	Income, and revenue accounts
500 Series	Electric O&M expenses

900 Series	Customer accounts, customer service and informational sales, and general and administrative expenses

Series 600, 700 and 800 are not major categories of cost that are used for cost of service studies.

B. Data for Marginal Cost Studies

The focus of marginal cost studies is on the estimated change in costs that results from providing an increment of service. The planning documents of the utility form the basis of the analysis, with those plans in turn being based on such tools and information as the output of the production costing model and the optimized generation planning model, the parameters established for reliability, stability and capability responsibility, and load and fuel forecasts. Costing for generation requires information on outage rates, operating and maintenance costs, alternate fuel capabilities and retirement schedules of existing plants, on the expected market for capacity purchases and sales, and on the capital and operating costs of alternate future generating units including their associated transmission.

Cost information on transmission, and to a lesser extent, distribution, is obtained from the utility's models of power flow analysis, with their associated transient stability programs, switching surge analyses and loss studies, and geographically specific load forecasts. Based on this information, the transmission and distribution planner will have developed a system expansion plan, the budget for which provides the cost data for the transmission and distribution portions of the marginal cost study.

Future customer and general and administrative costs, and in less sophisticated studies distribution costs as well, are not thought to vary significantly from the immediate historically incurred costs. Therefore, the sources of data for a marginal study will be the historic account data.

V. THE COST ALLOCATION PROCESS

A. Cost Functionalization

Once the relevant data on investment and operating costs are gathered and the relevance determined by the type of study and unique circumstances of each utility, the costs are then separated according to function. The typical functions used in an electric utility cost allocation study are:

- Production or purchased power

- Transmission
- Distribution
- Customer service and facilities
- Administrative and general

Each utility is a unique entity whose design has been dictated by the customer density, the age of the system, the customer mix, the terrain, the climate, the design preferences of management, the planning for the future, and the individual power companies that have merged to form the utility. Some utilities have generation plant, while others are only distribution systems. Therefore, the degree or complexity of functionalization will depend on the individual utility and the regulatory environment. The advent of computers encouraged a trend towards more detailed functionalization.

The assignment of costs to each function will generally follow the accounting categories defined in the USOA. At times, however, there will be exceptions. In such cases, the purpose of functionalization, not the accounting treatment, must drive the distribution of the functional costs for the cost study.

Following are descriptions of the typical cost functions used in an electric utility cost allocation study.

1. The Production Function

The production function consists of the costs associated with power generation and wholesale purchases. This includes the fossil fired, nuclear, hydro, solar, wind and other generating units. The costs associated with the purchase of power and its delivery to the bulk transmission system are also included.

2. The Transmission Function

The transmission function includes the assets and expenses associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities and to the various regions or load centers of the utility's system.

3. The Distribution Function

The distribution function encompasses the radial distribution system that connects the customer to the transmission system. The distribution function is normally extensively subdivided in order to recognize the non-utilization of certain types of plant by particular customer classes. Since customers served at the primary distribution voltage do not utilize the plant necessary to transform the voltage to the secondary levels, the cost causation criteria requires that they not be allocated the cost associated with the secondary distribution system.

4. The Customer Service and Facilities Function

The customer service and facilities function includes the plant and expenses that are associated with providing the service drop and meter, meter reading, billing and collection, and customer information and services. These investments and expenses are generally considered to be made and incurred on a basis related to the number of customers (by class) and are, therefore, of a fixed overhead nature.

5. Administrative and General Function

The administrative and general function includes the management costs, administrative buildings, etc. that cannot be directly assigned to the other major cost functions. These costs may be functionalized by relating them to specific groups of costs or other characteristics of the major cost functions, and then allocated on the same basis as the other costs within the function.

B. Classification of Costs

The next step is to separate the functionalized costs into classifications based on the components of utility service being provided. The three principal cost classifications for an electric utility are demand costs (costs that vary with the KW demand imposed by the customer), energy costs (costs that vary with the energy or KWH that the utility provides), and customer costs (costs that are directly related to the number of customers served).

After costs are functionalized into the primary functions, some can be identified as logically incurred to serve a particular customer or customer class. For example, a radial distribution line that serves only a particular customer may be assigned directly to that customer. Similarly, all the investment and expenses associated with luminaires and poles installed for street and private area lights are directly assigned to the lighting class(es). Segregation of these costs in a sense reverses the classification and allocation steps, as the costs are first allocated to the customer and subsequently classified as demand, energy or customer to determine how the customer is to be charged.

Typical cost classifications used in cost allocation studies are summarized below.

Typical Cost Function	Typical Cost Classification
Production	Demand Related Energy Related
Transmission	Demand Related Energy Related
Distribution	Demand Related Energy Related Customer Related
Customer Service	Customer Related Demand Related

The typical cost classifications shown above reflect the following types of assumptions regarding cost causation for electric utilities.

1. Production

Costs that are based on the generating capacity of the plant, such as depreciation, debt service and return on investment, are demand-related costs. Other costs, such as cost of fuel and certain operation and maintenance expenses, are directly related to the quantity of energy produced. In addition, capital costs that reduce fuel costs may be classified as energy related rather than demand related. In the case of purchased power, demand charges are normally assumed to be demand related and energy charges are normally assumed to be energy related. Fuel inventory may be either demand or energy related.

2. Transmission and Subtransmission

The costs of transmission and subtransmission are generally considered fixed costs that do not vary with the quantity of energy transmitted. However, to the extent that transmission investment enables a utility to avoid line losses, some portion of transmission may be classified as energy related.

3. Distribution

The costs of electric distribution systems are affected primarily by demand and by the number of customers. As in transmission, it may be possible to identify some energy component of the cost.

4. Customer Service

Costs functionalized as customer service are related to the number of customers and, therefore, can be classified as customer costs as well.

In any of these functions, costs that are associated with service to a specific customer or customer class may be directly assigned. Although cost classifications are usually based on considerations similar to those listed above, there are numerous instances in which other methods of cost classification are considered. These various circumstances will be discussed in the chapters in Sections II and III.

C. Allocation of Costs Among Customer Classes

After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. The three principal customer classes are residential, commercial, and industrial. It may be reasonable to subdivide the three classes based on characteristics such as size of load, the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not. Additional customer classes that may be established are street lighting, municipal, and agricultural.

Once the customer classes to be used in the cost allocation study have been designated, the functionalized and classified costs are allocated among the classes as follows:

- Demand-related costs - Allocated among the customer classes on the basis of demands (KW) imposed on the system during specific peak hours.
- Energy-related costs - Allocated among the customer classes on the basis of energy (KWH) which the system must supply to serve the customers.
- Customer-related costs - Allocated among the customer classes on the basis of the number of customers or the weighted number of customers. Normally, weighting the number of customers in the various classes is based on an analysis of the relative levels of customer-related costs (service lines, meters, meter reading, billing, etc.) per customer.

This manual only discusses the major costing methodologies. It recognizes that no single costing methodology will be superior to any other, and the choice of methodology will depend on the unique circumstances of each utilty. Individual costing methodologies are complex and have inspired numerous debates on application, assumptions and data. Further, the role of cost in ratemaking is itself not without controversy.

Dr. James Bonbright, whose Principles of Public Utility Rates is the classic examination of regulation and ratemaking, wrote:

> "Of all of the many problems of rate making that are bedeviled by unresolved disputes about issues of fairness, the one that deserves first rank for frustration is that concerned with the apportionment among different classes of consumers of the demand costs or capacity costs....Here, notions of 'fair apportionment' are almost sure to conflict with economists' convictions as to the relevant cost allocations. But these notions are themselves neither stable nor uniform, although they reveal a general tendency in favor of a fairly wide spreading out of the costs, as butter would be spread over bread in a well-made sandwich. Awareness of these unresolved conflicts about 'fair' cost apportionment has lead the British economist Professor W. Arthur Lewis to exclaim that, in rate determination, 'equity is the mother of confusion.'"

The purpose of this manual is to clarify, if not resolve, some of that confusion.

CHAPTER 3

DEVELOPING TOTAL REVENUE REQUIREMENTS

A utility, in order to remain viable, must be given the opportunity to recover its prudently incurred total cost of providing electric service to its various classes of customers. Cost of service is usually defined to include all of a utility's operating expenses, plus a reasonable return on its investment devoted to the service of the ratepaying public. Accordingly, it is incumbent on the utility to ensure that the rates it charges for electric services are sufficient to recover its total costs. The total theoretical revenues a utility is authorized to collect through its rates for its various types of service is called the total revenue requirement, or the total cost of service.

The total revenue requirement of a utility is equal to the sum of the costs to serve all its various classes of customers. Since a utility's rates are generally regulated by two or more governmental agencies, revenue requirements under different jurisdictions are usually established on the basis of cost allocation studies; but the rates so established can and often do reflect differing cost bases among jurisdictions.

The derivation of revenue requirements for each jurisdiction's classes of service requires findings in the following areas: (1) The proper development of rate base and fair rate of return to determine return allowances on investment; (2) allowable levels of operating expenses; and (3) proper recognition of other operating revenues, including those for opportunity-type sales of electricity. This chapter, therefore, will first discuss test year concepts, then, the major elements used to determine revenue requirements will be presented.

I. TEST YEAR CONCEPTS

Regulatory agencies recognize that the rates they establish are likely to remain in effect for an indeterminate period into the future. Consequently, rates so established are usually developed using the most current actual or projected cost and sales information for a selected time period. The period used is normally 12 months in length -- referred to as the test year or test period -- and normally includes cost and sales data which are expected to be representative of those that will be experienced during the time the rates are likely to remain in effect.

Three types of test periods are in common usage. Some agencies have adopted test periods which use the latest 12 months of historical data as the basis for setting rates. For instance, if a utility filed changed rates to become effective on January 1, 1987, the historical test year adopted to support those new rates might very well cover the actual data for the period July 1, 1985 to June 30, 1986.

Other agencies, however, have adopted the projected test year concept. In this situation, for rates proposed to be effective January 1, 1987, the utility might be required to support its proposal on data projected for the calendar year 1987.

The third type of test year uses a combination of actual and projected data. For a filing effective as of January 1, 1987, the utility might be required to base its rates on a test period using actual data for the last six months of 1986 and projected data for the first six months of 1987.

The type of test period adopted by a utility to support its rate proposals depends upon a number of factors, the most important of which is the requirement of the regulatory body within whose jurisdiction the utility operates. Other factors may include the degree of rate surveillance practiced by the regulator, the cost characteristics of the utility, including expected changes in the utility's pattern of operation, and automatic cost tracking mechanisms built into the utility's rates.

A. Pro Forma Adjustments of Historical Data

Where projected test periods are not used, rates must be developed on the basis of past cost experience. In order to reflect the cost conditions that may occur during the actual effectiveness of the rates, most agencies permit adjustments to the actual data to reflect changed conditions, to correct for unusual events during the recorded period, or to include costs estimated for a time period in the near future. The goal is to adjust the actual costs to present normal operating conditions as accurately as possible, so that rates resulting from a proceeding are appropriate for application in the immediate future. An example of costs that may require adjustment or normalization are power production and purchased power expense. The addition of new significant generating capacity to a system normally requires the adjustment of accounts to recognize the fixed charges and operating expense mixture change due to a different generation dispatch. Enacted legislation that amends Federal or State income tax provisions from those in effect during the actual test year would require the recalculation of income tax. It should be noted that use of a projected test period would generally obviate the need to make such adjustments for known and measurable changes because projected test periods are developed using forecast data which would presumably already reflect such changes. The revenue requirements calculated using a projected test year should be the same as those calculated using a historic test year plus all pro forma adjustments, including sales adjustments.

In addition to pro forma adjustments to the revenue requirements, most agencies allow reasonable regulatory expenses that are incurred by the utility in preparing, filing and defending its application. These regulatory expenses are often amortized over the period of time that the requested rates are expected to be in effect.

II. REVENUE REQUIREMENT DETERMINATIONS

Revenue requirements may be expressed in mathematical terms as follows:

$$RR = \left(\frac{T_r}{1-T_r} + 1\right) \times (OE + R + FITA + SITA - OR)$$

Where:

RR	=	Total retail service revenue requirement
T_r	=	Revenue tax rate, if applicable
OE	=	Operating expenses, excluding income and revenue taxes
R	=	Return
FITA	=	Federal income taxes allowable
SITA	=	State income taxes allowable
OR	=	Other operating revenue, exclusive of revenue taxes

The elements that are applied in the above formula are the test year costs, plus pro forma adjustments if a historical test year is used. These revenue requirement elements are discussed in the balance of this chapter.

A. Rate Base

Rate base is the investment basis established by a regulatory authority upon which a utility is allowed to earn a fair return. Generally, the amount established as the plant component of rate base represents the amount of property considered to be used and useful in the public service and may be based on a number of different valuation methods, e.g., fair value, reproduction cost or original cost.[1] Rate base also generally includes items other than investment property, i.e., cash working capital, which require capital funding by the utility to carry out its business affairs.

[1]In developing rate base, because of the various ages of plant and equipment, commissions have adopted a number of valuation methodologies. Three of the more commonly used methods are: (1) original cost, which is the cost of utility property at the time such property was brought into service; (2) fair value, which is based on the regulatory agency's judgment, may include consideration of reproduction cost, original cost, replacement cost, market value, or other elements; and (3) reproduction cost, which is the estimated cost to reproduce existing plant facilities in their present form and capabilities at current cost levels.

This subsection discusses the elements that are generally included in rate base, where rate base is based on net original investment costs. The development of such rate base is as follows:

RATE BASE

Original Cost of Electric Plant in Service
Less: Accumulated depreciation reserves
: Accumulated provision for deferred income taxes (Accounts 281-283)
: Operating reserves
Plus: Electric plant held for future use
: Construction work in progress (if allowed)
: Working capital
: Accumulated provision for deferred income taxes (Account 190)
Equals: Rate Base

1. Electric Plant in Service

Electric utility plant in service consists of all original cost investment expenditures that are installed by the utility to provide its electric services. As discussed in chapter 2, such plant investment is functionalized to four main categories -- production, transmission, distribution, and general and intangible plant -- for the purpose of properly assigning customer cost responsibilities in each. If the utility is a combination utility, i.e., it provides more than one type of utility service, such as gas, water or steam, then it may have plant that is common to all types of utility service. In this situation, common plant must be apportioned among the various utility operations to ensure that all types of the utility's customers share in the associated costs.

2. Accumulated Depreciation Reserves

Accumulated depreciation reserves represent, at some point in time, the total accrued annual depreciation expenses that the utility has charged to operating expenses for plant in service. The accrual, or depreciation rates, are based upon the utility's determination of the number of years of service expected from plant investments and the expected dismantlement costs when the units of property are removed from service, less the expected salvage value. The yearly depreciation expense amount is determined by multiplying the depreciation rate times the original cost of the plant investment. The total accumulated depreciation reserve amounts are deducted from the original plant in service investment amounts in the development of rate base.

3. Accumulated Provision For Deferred Income Taxes

The accumulated provision for deferred income taxes represents, at some point in time, the net accumulated annual income tax effects arising from timing differences between the periods in which transactions affected taxable income and the periods in which they entered into the determination of taxable income for book (ratemaking) purposes. For Accounts 281 through 283, the deferred amounts usually represent normalization of the book/tax timing differences where tax deductions exceed book expenses. For example, the additional tax deductions resulting from the use of some form of accelerated depreciation for tax purposes instead of straight-line or other non-accelerated depreciation methods used for book purposes, are normalized and recorded in Accounts 281 through 283. These amounts represent the taxes the utility will have to pay some time in the future when timing differences reverse, i.e., when book expense exceeds the amount available to be used as a tax deduction. Since these account balances are funded by the ratepayer and represent sums collected by the utility in advance of actual payment to Federal and State treasuries, they are used as reductions to rate base. Conversely, there are balances which are generated when the utility is required to pay taxes in advance of book (rate) recognition of certain items. These balances are added to rate base.

4. Electric Plant Held For Future Use

Electric plant held for future use refers to land and physical plant and equipment not currently used and useful in the provision of electric service, but which are owned and held by a utility for use some time in the future. These investments may include land which was purchased as the future site of a large generating station, or may include plant which was acquired for future use, or plant which was previously used in providing electric service, but was temporarily suspended from service pending its reuse at some future time. While land acquisitions for future use are routinely permitted in rate base by regulators, plant and equipment acquired for this purpose are not. As a general rule, plant investments held for future use, in order to normally qualify for rate base treatment, cannot remain in an indefinite status, but must be held under a definite plan of future use.

5. Construction Work In Progress

Construction work in progress (CWIP) represents the balance of funds invested in utility plant under construction, but not yet placed in service. Some or all of construction work in progress may be eligible for inclusion in rate base, depending on the practices and policies of the utility's regulators so that the utility can recover currently some or all of the carrying costs of new facilities prior to the plant actually entering service.

Where CWIP is not permitted in rate base, a utility is allowed to capitalize as part of its construction costs an allowance for funds used during construction (AFUDC) as deferred compensation for its construction financing costs. Afterwards, when construction is completed and plant enters rate base, the accumulated AFUDC will be included as part of the investment cost of the plant and will be captured as part of depreciation expenses charged annually to operating expenses over the book life of the facility.

6. Working Capital

Working capital is a rate base element that a utility is allowed in order for it to maintain the required operational supply inventories to meet its prepayment obligations and to provide it with the cash it needs to meet its operating expenses between the time it renders service and when it collects revenues for those services. The three principal categories of working capital are plant materials and supplies, prepayments and cash working capital. Plant materials and supplies include all fuel stock inventories, replacement equipment on hand but not yet placed in service, and supplies that will be needed on a continuous basis for the operation and maintenance of utility plant. Prepayments include items such as prepaid insurance, rents, taxes and interest. Cash working capital is an allowance that is granted by regulators to cover the day-to-day cash needs of a utility. Thus, funds continually invested in these three elements of working capital impose carrying costs on the utility for which it is entitled to be compensated, if such incurrence is found to be prudent.

B. Fair Rate of Return

A fair rate of return is one that will allow the utility to recover its costs of all classes of capital used to finance its rate base. These classes of capital are generally debt and stockholder common equity. The embedded costs of long-term debt and preferred stock are fixed and can be readily computed. The cost of a utility's common equity is reflected in the price that investors are willing to pay for the company's stock and that cost has to be estimated. The cost of common equity is, by far, the most controversial aspect of rate of return determinations. Methods used to arrive at the cost of common equity include the discounted cash flow, comparable earnings, risk premium, and the capital asset pricing model.

A utility is allowed the opportunity to earn a reasonable return on its investment that is prudent and dedicated to the public service. The return dollars a utility is entitled to collect is determined by multiplying the rate base by the rate of return, as follows:

$$R = RB \times r$$

<u>Where:</u>

R	= Return
RB	= Rate base
r	= Rate of return (a percentage)

Return is the amount of money a utility may earn over and above operating expenses, net of income taxes. Included in the return amount is interest on debt, dividends for preferred stock as well as the allowed earnings on common equity.

C. <u>Operating Expenses</u>

Operating expenses are a group of expenses incurred in connection with a utility's operations and include: (1) operation and maintenance expenses; (2) depreciation expenses; (3) miscellaneous amortization expenses; (4) taxes other than income taxes; (5) income taxes; and (6) other operating revenues.

1. Operation and Maintenance Expenses

Operation and maintenance (O&M) expenses are the costs incurred by a utility in the course of supplying its services. O&M expenses include the costs of labor, maintenance, fuel, administrative expenses, regulatory commission expenses, materials and supplies, (to the extent such items are routine expenditures, not capital investments), purchased power and various other service-related expenses.

2. Depreciation Expense

Depreciation expense is the annual charge made against income to provide for distribution of the cost of plant over its estimated useful life. Among the factors considered in developing the annual charge are wear and tear, decay, obsolescence, and any additional requirements that may be imposed by regulators.

3. Miscellaneous Amortization Expenses

Miscellaneous amortization expenses represent costs incurred by a utility that are amortized over a specified period of time for rate purposes. Examples of such costs are cancelled plant amortizations and extraordinary property losses.

4. Taxes Other Than Income Taxes

Taxes other than income taxes include all payments a utility must make to various taxing authorities. Such taxes may be levied on utility sales and property; and for social security, unemployment compensation, franchise, and state and federal excise. Since the utility must pay these taxes in the process of doing business, such costs are eligible for recovery from customers. It should be noted that while revenue taxes (or gross receipts taxes) are considered as "other" taxes, such taxes are levied on all or a portion of the utility's revenues. Consequently, any incremental changes in a utility's revenue requirement determination will produce a corresponding change in these tax allowances.

5. Income Taxes

Income taxes, both federal and state, are levied on a utility's earnings. Consequently, such taxes represent a cost of doing business and are therefore recoverable from a utility's ratepayers. The development of income tax allowances included in rates is a complex process that requires familiarity with federal and state tax laws as well as accounting and ratemaking practices and principles that are adopted by the regulator.

6. Other Operating Revenues

Other operating revenues include all revenues received from sources other than retail sales of electricity. These amounts are collected by a utility for other services rendered. An example of these revenue sources is when a utility may provide space on its transmission or distribution poles for the use of cable television lines and receive revenues therefrom in the form of rental payments. In addition, revenues collected from non-firm opportunity sales or coordination type sales, are normally treated in the same manner as other operating revenues. The retail service customers are normally given credit for these revenues through a reduction in their revenue requirements since they are produced through the use of plant or utility personnel, the expenses of which are borne by the utility's retail service customers.

SECTION II

EMBEDDED COST STUDIES

SECTION II of the Cost Allocation Manual contains five chapters that detail the dominant method of cost allocation -- the embedded cost study; that is, cost allocation methods based on historical or known costs. Each chapter presents allocation methods for specific components of cost.

Chapter 4 describes embedded cost methods for allocating production costs. It first discusses functionalization and classification and differentiates between costs that are demand-related and energy-related. Next, a variety of methods that can be used to allocate production plant costs are presented with numerical examples. Finally, observations on choosing an embedded cost method are included along with data needs.

Chapter 5 discusses methods of transmission cost functionalization, with detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. Finally, the treatment of wheeling costs is discussed.

Chapter 6 provides an overview of distribution plant cost allocation. It discusses the classification of distribution costs between energy, demand and customers. Two methods used to determine demand and customer components are outlined -- the minimum-size and minimum-intercept methods. Procedures used to calculate demand and allocation factors are finally presented.

Chapters 7 and 8 briefly outline the classification and allocation of customer-related costs and investment, administrative and general expenses, respectively.

Schedule NLP-SR1

CHAPTER 4

EMBEDDED COST METHODS FOR ALLOCATING PRODUCTION COSTS

Of all utility costs, the cost of production plant -- i.e., hydroelectric, oil and gas-fired, nuclear, geothermal, solar, wind, and other electric production plant -- is the major component of most electric utility bills. Cost analysts must devise methods to equitably allocate these costs among all customer classes such that the share of cost responsibility borne by each class approximates the costs imposed on the utility by that class.

The first three sections of this chapter discusses functionalization, classification and the classification of production function costs that are demand-related and energy-related. Section four contains a variety of methods that can be used to allocate production plant costs. The final three sections include observations regarding fuel expense data, operation and maintenance expenses for production and a summary and conclusion.

I. THE FIRST STEP: FUNCTIONALIZATION

Functionalization is the process of assigning company revenue requirements to specified utility functions: Production, Transmission, Distribution, Customer and General. Distinguishing each of the functions in more detail -- subfunctionalization -- is an optional, but potentially valuable, step in cost of service analysis. For example, production revenue requirements may be subfunctionalized by generation type -- fossil, steam, nuclear, hydroelectric, combustion turbines, diesels, geothermal, cogeneration, and other. Distribution may be subfunctionalized to lines (underground and overhead) substations, transformers, etc. Such subfunctional categories may enable the analyst to classify and allocate costs more directly; they may be of particular value where the costs of specific units or types of units are assigned to time periods. But, since this is a manual of cost allocation, and this is a chapter on production costs, we won't linger over functionalization or consider costs in other functions. The interested reader will consult generalized texts on the subject. It will suffice to say here that all utility costs are allocated after they are functionalized.

II. CLASSIFICATION IN GENERAL

Classification is a refinement of functionalized revenue requirements. Cost classification identifies the utility operation -- demand, energy, customer -- for which functionalized dollars are spent. Revenue requirements in the production and transmission functions are classified as demand-related or energy-related. Distribution revenue requirements are classified as either demand-, energy- or customer-related.

Cost classification is often integrated with functionalization; some analysts do not distinguish it as an independent step in the assignment of revenue requirements. Functionalization is to some extent reflected in the way the company keeps its books; plant accounts follow functional lines as do operation and maintenance (O&M) accounts. But to classify costs accurately the analyst more often refers to conventional rules and his own best judgment. Section IV of this chapter discusses three major methods for classifying and allocating production plant costs. We will see that the peak demand allocation methods rely on conventional classification while the energy weighting methods and the time-differentiated methods of allocation require much attention to classification and, indeed, are sophisticated classification methods with fairly simple allocation methods tacked on.

The chart below is a basic example of an integrated functionalization/classification scheme.

FUNCTIONALIZED CLASSIFICATION OF ELECTRIC UTILITY COSTS

	Cost Classes			
Functions	**Demand**	**Energy**	**Customer**	**Revenue**
Production				
Thermal	X	X	N/A	N/A
Hydro	X	X	N/A	N/A
Other	X	X	N/A	N/A
Transmission	X	X	X	N/A
Distribution	X	X	X	N/A
OH/UG Lines	X	X	X	N/A
Substations	X	X	X	N/A
Services	N/A	N/A	X	N/A
Meters	N/A	N/A	X	N/A
Customer	N/A	N/A	X	X

III. CLASSIFICATION OF PRODUCTION FUNCTION COSTS

Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related.

A. Cost Accounting Approach

Production plant costs are either fixed or variable. Fixed production costs are those revenue requirements associated with generating plant owned by the utility, including cost of capital, depreciation, taxes and fixed O&M. Variable costs are fuel costs, purchased power costs and some O&M expenses. Fixed production costs vary with capacity additions, not with energy produced from given plant capacity, and are classified as demand-related. Variable production costs change with the amount of energy produced, delivered or purchased and are classified as energy- related. Exhibit 4-1 summarizes typical classification of FERC Accounts 500-557.

EXHIBIT 4-1

CLASSIFICATION OF PRODUCTION PLANT

CLASSIFICATION OF RATE BASE[1]

Production Plant

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
301-303	Intangible Plant	x	-
310-316	Steam Production	x	x
320-325	Nuclear Production	x	-
330-336	Hydraulic Production	x	x[2]
340-346	Other Production	x	-

Exhibit 4-1
(Continued)
CLASSIFICATION OF PRODUCTION PLANT

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

CLASSIFICATION OF EXPENSES[1]
Production Plant

Steam Power Generation Operations

500	Operating Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
501	Fuel	-	x
502	Steam Expenses	x[4]	x[4]
503-504	Steam From Other Sources & Transfer. Cr.	-	x
505	Electric Expenses	x[4]	x[4]
506	Miscellaneous Steam Pwr Expenses	x	-
507	Rents	x	-

Maintenance

510	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
511	Structures	x	-
512	Boiler Plant	-	x
513	Electric Plant	-	x
514	Miscellaneous Steam Plant	-	x

Nuclear Power Generation Operation

517	Operation Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
518	Fuel	-	x
519	Coolants and Water	x[4]	x[4]
520	Steam Expense	x[4]	x[4]
521-522	Steam From Other Sources & Transfe. Cr.	-	x
523	Electric Expenses	x[4]	x[4]
524	Miscellaneous Nuclear Power Expenses	x	-
525	Rents	x	-

EXHIBIT 4-1

(Continued)

CLASSIFICATION OF EXPENSES [1]

FERC Uniform System of Accounts No.	Description	Demand Related	Energy Related

Maintencance

528	Supervision & Engineering	Prorated on Labor[3]	Prorated on Labor[3]
529	Structures	x	-
530	Reactor Plant Equipment	-	x
531	Electric Plant	-	x
532	Miscellaneous Nuclear Plant	-	x

Hydraulic Power Generation Operation

535	Operation Supervision and Engineering	Prorated on Labor[3]	Prorated on Labor[3]
536	Water for Power	x	-
537	Hydraulic Expenses	x	-
538	Electric Expense	x[4]	x[4]
539	Misc Hydraulic Power Expenses	x	-
540	Rents	x	-

Maintenance

541	Supervision & Engineering	Prorated On Labor[3]	Prorated On Labor[3]
542	Structures	x	-
543	Reservoirs, Dams, and Waterways	x	x
544	Electric Plant	x	x
545	Miscellaneous Hydraulic Plant	x	x

Exhibit 4-1
(Continued)

FERC Uniform System of Account	Description	Demand Related	Energy Related
	CLASSIFICATION OF EXPENSES[1]		
	Other Power Generation Operation		
546, 548-554	All Accounts	x	-
547	Fuel	-	x
	Other Power Supply Expenses		
555	Purchased Power	x[5]	x[5]
556	System Control & Load Dispatch	x	-
557	Other Expenses	x	-

[1] Direct assignment or "exclusive use" costs are assigned directly to the customer class or group that exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2] In some instances, a portion of hydro rate base may be classified as energy related.

[3] The classification between demand-related and energy-related costs is carried out on the basis of the relative proportions of labor cost contained in the other accounts in the account grouping.

[4] Classified between demand and energy on the basis of labor expenses and material expenses. Labor expenses are considered demand-related, while material expenses are considered energy-related.

[5] As-billed basis.

The cost accounting approach to classification is based on the argument that plant capacity is fixed to meet demand and that the costs of plant capacity should be assigned to customers on the basis of their demands. Since plant output in KWH varies with system energy requirements, the argument continues, variable production costs should be allocated to customers on a KWH basis.

B. Cost Causation

Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability (LOLP), loss of load hours (LOLH), reserve margin, or expected unserved energy (EUE); and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.

IV. METHODS FOR CLASSIFYING AND ALLOCATING PRODUCTION PLANT COSTS

In the past, utility analysts thought that production plant costs were driven only by system maximum peak demands. The prevailing belief was that utilities built plants exclusively to serve their annual system peaks as though only that single hour was important for planning. Correspondingly, cost of service analysts used a single maximum peak approach to allocate production costs. Over time it became apparent to some that hours other than the peak hour were critical from the system planner's perspective, and utilities moved toward multiple peak allocation methods. The Federal Energy Regulatory Commission began encouraging the use of a method based on the 12 monthly peak demands, and many utilities accordingly adopted this approach for allocating costs within their retail jurisdictions as well as their resale markets.

This section is divided into three parts. The first two contain a discussion of peak demand and energy weighted cost allocation methods. The third part covers time-differentiated cost of service methods for allocating production plant costs. Tables 4-1 through 4-4 contain illustrative load data supplied by the Southern California Edison Company for monthly peak demands, summer and winter peak demands, class noncoincident peak demands, on-peak and off-peak energy use. These data are used to illustrate the derivation of various demand and energy allocation factors throughout this Section as well as Section III.

The common objective of the methods reviewed in the following two parts is to allocate production plant costs to customer classes consistent with the cost impact that the class loads impose on the utility system. If the utility plans its generating capacity additions to serve its demand in the peak hour of the year, then the demand of each class in the peak hour is regarded as an appropriate basis for allocating demand-related production costs.

If the utility bases its generation expansion planning on reliability criteria -- such as loss of load probability or expected unserved energy -- that have significant values in a number of hours, then the classes' demands in hours other than the single peak hour may also provide an appropriate basis for allocating demand-related production costs. Use of multiple-hour methods also greatly reduces the possibility of atypical conditions influencing the load data used in the cost allocation.

TABLE 4-1

CLASS MW DEMANDS AT THE GENERATION LEVL IN THE TWELVE MONTHLY SYSTEM PEAK HOURS

(1988 Example Data)

Rate Class	January	February	March	April	May	June	July	August
DOM	3,887	3,863	2,669	2,103	2,881	3,338	4,537	4,735
LSMP	3,065	3,020	3,743	4,340	4,390	4,725	5,106	5,062
LP	2,536	2,401	2,818	2,888	3,102	3,067	3,219	3,347
AG&P	84	117	144	232	405	453	450	447
SL	94	105	28	0	0	0	0	0
Total	9,666	9,506	9,402	9,563	11,318	11,583	13,312	13,591

Rate Class	September	October	November	December	Total	Average
DOM	4,202	2,534	3,434	4,086	42,268	3,522
LSMP	5,106	4,736	3,644	3,137	50,614	4,218
LP	3,404	3,170	2,786	2,444	35,181	2,932
AG&P	360	284	138	75	3,189	266
SL	0	0	103	126	457	38
Total	13,072	10,724	10,105	9,868	131,709	10,976

Note: The rate classes and their abbreviations for the example utility are as follows:

DOM - Domestic Service
LSMP - Lighting, Small and Medium Power
LP - Large Power
AG&P - Agricultural and Pumping
SL - Street Lighting

TABLE 4-2

CLASS MW DEMANDS AT THE GENERATION LEVEL IN THE 3 SUMMER AND 3 WINTER SYSTEM PEAK HOURS

(1988 Example Data)

	Winter				Summer			
Rate Class	**January**	**February**	**December**	**Average**	**July**	**August**	**September**	**Average**
DOM	3,887	3,863	4,086	3,946	4,537	4,735	4,202	4,491
LSMP	3,065	3,020	3,137	3,074	5,106	5,062	5,106	5,092
LP	2,536	2,401	2,444	2,460	3,219	3,347	3,404	3,323
A&P	84	117	75	92	450	447	360	419
SL	94	105	126	108	0	0	0	0
Total	9,666	9,506	9,868	9,680	13,312	13,591	13,072	13,325

Peak demand methods include the single coincident peak method, the summer and winter peak method, the twelve monthly coincident peak method, multiple coincident peak method, and an all peak hours approach. Energy weighting methods include the average and excess method, equivalent peaker method, the base and peak method, and methods using judgmentally determined energy weightings, such as the peak and average method and variants thereof.

A. Peak Demand Methods

Cost of service methods that utilize a peak demand approach are characterized by two features: First, all production plant costs are classified as demand-related. Second, these costs are allocated among the rate classes on factors that measure the class contribution to system peak. A customer or class of customers contributes to the system maximum peak to the extent that it is imposing demand at the time of -- coincident with -- the system peak. The customer's demand at the time of the system peak is that customer's "coincident" peak. The variations in the methods are generally around the number of system peak hours analyzed, which inturn depends on the utility's annual load shape and on system planning considerations.

Peak demand methods do not allocate production plant costs to classes whose usage occurs outside peak hours, to interruptible (curtailable) customers.

TABLE 4-3

DEMAND ALLOCATION FACTORS

Rate Class	MW Demand At Annual System Peak (MW)	1 CP Alloc. Factor (Percent)	Average of the 12 Monthly CP Demands (MW)	12 CP Alloc. Factor (Percent)	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	3S/3W Alloc. Factor (Percent)	Noncoinc. Peak Demand MW	NCP Alloc. Factor (Percent)
DOM	4,735	34.84	3,522	32.09	4,491	3,946	36.67	5,357	36.94
LSMP	5,062	37.25	4,218	38.43	5,092	3,074	35.50	5,062	34.91
LP	3,347	24.63	2,932	26.71	3,323	2,460	25.14	3,385	23.34
AG&P	447	3.29	266	2.42	419	92	2.22	572	3.94
SL	0	0.00	38	0.35	0	108	0.47	126	0.87
Total	13,591	100.00	10,976	100.00	13,325	9,680	100.00	14,502	100.0

Note: Some columns may not add to indicated totals due to rounding.

TABLE 4-4

ENERGY ALLOCATION FACTORS

Rate Class	Total Annual Energy Used (MWH)	Total Energy Allocation Factor (%)	On-Peak Energy Cons. (MWH)	On-Peak Energy Allocation Factor (%)	Off-Peak Energy Cons. (MWH)	Off-Peak Energy Allocation Factor (%)
DOM	21,433,001	30.96	3,950,368	32.13	17,482,633	30.71
LSMP	23,439,008	33.86	4.452,310	36.21	18,986,698	33.35
LP	21,602,999	31.21	3,474,929	28.26	18,128,070	31.85
AG&P	2,229,000	3.22	335,865	2.73	1,893,135	3.33
SL	513,600	0.74	80,889	0.66	432,711	0.76
Total	69,217,608	100.00	12,294,361	100.00	56,923,247	100.00

Note: Some columns may not add to indicated totals due to rounding.

1. Single Coincident Peak Method (1-CP)

O*bjective:* The objective of the single coincident peak method is to allocate production plant costs to customer classes according to the load of the customer classes at the time of the utility's highest measured one-hour demand in the test year, the class coincident peak load.

Data Requirements: The 1-CP method uses recorded and/or estimated monthly class peak demands. In a large system, this may require complex statistical sampling and data manipulation. A competent load research effort is a valuable asset.

Implementation: Table 4-1 contains illustrative load data for five customer classes for 12 months of a test year. The analyst simply translates class load at the time of the system peak into a percentage of the company's total system peak, and applies that percentage to the company's production-demand revenue requirements; that is, to the revenue requirements that are functionalized to production and classified to demand. This operation is shown in Table 4-5.

TABLE 4-5

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SINGLE COINCIDENT PEAK METHOD

Rate Class	MW Demand at Generator at System Peak	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	4,735	34.84	369,461,692
LSMP	5,062	37.25	394,976,787
LP	3,347	24.63	261,159,089
AG&P	447	3.29	34,878,432
SL	0	0.00	0
TOTAL	13,591	100.00	$ 1,060,476,000

2. Summer and Winter Peak Method

Objective: The objective of the summer and winter peak method is to reflect the effect of two distinct seasonal peaks on customer cost assignment. If the summer and winter peaks are close in value, and if both significantly affect the utility's generation expansion planning, this approach may be appropriate.

Implementation: The number of summer and winter peak hours may be determined judgmentally or by applying specified criteria. One method is simply to average the class contributions to the summer peak hour demand and the winter peak hour demand. Another method is to choose those summer and winter hours where the peak demand or reliability index passes a specified threshold value. Clearly, the selection of the hours is critical and the establishment of selection criteria is particularly important. These cost of service judgements must be made jointly with system planners and supported with good data. The analyst should review FERC cases, where this issue often comes up. Table 4-6 shows the allocators and resulting allocations of production plant revenue responsibility for the example using the three highest summer and three highest winter coincident peak demand hours.

TABLE 4-6

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE SUMMER AND WINTER PEAK METHOD

Rate Class	Average of the 3 Summer CP Demands (MW)	Average of the 3 Winter CP Demands (MW)	Demand Allocation Factor	Total Class Production Plant Revenue Requirmt
DOM	4,491	3,946	36.67	388,925,712
LSMP	5,092	3,074	35.50	376,433,254
LP	3,323	2,460	25.14	266,582,600
AG&P	419	92	2.22	23,555,889
SL	0	108	0.47	4,978,544
TOTAL	13,325	9,680	100.00	$ 1,060,476,000

3. The Sum of the Twelve Monthly Coincident Peak (12 CP) Method

Objective: This method uses an allocator based on the class contribution to the 12 monthly maximum system peaks. This method is usually used when the monthly peaks lie within a narrow range; i.e., when the annual load shape is not spiky. The 12-CP method may be appropriate when the utility plans its maintenance so as to have equal reserve margins, LOLPs or other reliability index values in all months.

Data Requirements: Reliable monthly load research data for each class of customers and for the total system is the minimum data requirement. The data can be recorded and/or estimated.

Implementation: Table 4-7 shows the derivation of the 12 CP allocator and the resulting allocation of production plant costs for the example case.

TABLE 4-7

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE TWELVE COINCIDENT PEAK METHOD

Rate Class	Average of 12 Coincident Peaks At Generation (MW)	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,522	32.09	340,287,579
LSMP	4,218	38.43	407,533,507
LP	2,932	26.71	283,283,130
AG&P	266	2.42	25,700,311
SL	38	0.35	3,671,473
TOTAL	10,976	100.00	$ 1,060,476,000

4. Multiple Coincident Peak Method

This section discusses the general approach of using the classes' demands in a certain number of hours to derive the allocation factors for production plant costs. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include: (1) all hours of the year with demands within 5 percent or 10 percent of the system's peak demand, and (2) all hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected unserved energy, or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the demand allocator.

5. All Peak Hours Approach

This method resembles the multiple CP approach except it bases the allocation of demand-related production plant costs on the classes' contributions to all defined, rather than certain specified, on-peak hours. This method requires scrutiny of all hours of the year to determine which are most likely to contribute to the need for the utility to add production plant. If the on-peak rating periods -- i.e., the hours or periods in which on-peak rates apply -- are properly defined, then all hours in the on-peak period are critical from the utility's planning perspective. Table 4-8 shows the allocators and resulting cost allocation based on the classes' shares of on-peak KWH for the example utility. For the example utility, the on-peak periods are from 5:00 p.m. to 9:00 p.m. on winter weekdays and from 12:00 noon to 6:00 p.m. on summer weekdays.

The on-peak hours may be defined using various criteria, such as those hours with a preponderance of actual peak demands, those with the majority of annual loss of load probabilities, loss of load hours or those in which other reliability indexes register critical values. Using this method requires satisfactory load research and computer capability to estimate the classes' loads in the defined on-peak periods.

TABLE 4-8

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE ALL PEAK HOURS APPROACH

Rate Class	Class On-Peak MWH At Generation	Allocation Factor	Total Class Production Plant Revenue Requirement
DOM	3,950,368	32.13	340,747,311
LSMP	4,452,310	36.21	384,043,376
LP	3,474,929	28.26	299,737,319
AG&P	335,865	2.73	28,970,743
SL	80,889	0.66	6,977,251
TOTAL	12,294,361	100.00	$ 1,060,476,000

Notes: The on-peak periods for the example utility are from 5:00 p.m. to 9:00 p.m. on weekdays in January through May and October through December, and from 12:00 noon to 6:00 p.m. on weekdays in June through September. Some columns may not add to indicated totals due to rounding.

6. Summary: Peak Demand Responsibility Methods

Table 4-9 is a summary of the allocation factors and revenue allocations for the methods described above. The most important observations to be drawn from this information are:

- The number of hours chosen as the basis for the demand allocator can have a significant effect on the revenue allocation, even for relatively small numbers of hours.
- The greater the number of hours used, the more the allocation will reflect energy requirements. If all 8,760 hours of a year were used, the demand and a KWH (energy) allocation factors would be the same.

TABLE 4-9

SUMMARY OF ALLOCATION FACTORS AND REVENUE RESPONSIBILITY FOR PEAK DEMAND COST ALLOCATION METHODS

	1 CP Method		3 Summer and 3 Winter Peak Method	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	34.84	369,461,692	36.67	388,925,712
LSMP	37.25	394,976,787	35.50	376,433,254
LP	24.63	261,159,089	25.14	266,582,600
AG&P	3.29	34,878,432	2.22	23,555,889
SL	0.00	0	0.47	4,978,544
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

	12 CP Method		All Peak Hours Approach	
Rate Class	**Allocation Factor (%)**	**Revenue Requirement**	**Allocation Factor (%)**	**Revenue Requirement**
DOM	32.09	340,287,579	32.13	340,747,311
LSMP	38.43	407,533,507	36.21	384,043,376
LP	26.71	283,283,130	28.26	299,737,319
AG&P	2.42	25,700,311	2.73	28,970,743
SL	0.35	3,671,473	0.66	6,977,251
TOTAL	100.00	$ 1,060,476,000	100.00	$ 1,060,476,000

Note: Some columns may not add to totals due to rounding.

B. Energy Weighting Methods

There is evidence that energy loads are a major determinant of production plant costs. Thus, cost of service analysis may incorporate energy weighting into the treatment of production plant costs. One way to incorporate an energy weighting is to classify part of the utility's production plant costs as energy-related and to allocate those costs to classes on the basis of class energy consumption. Table 4-4 shows allocators for the example utility for total energy, on-peak energy, and off-peak energy use.

In some cases, an energy allocator (annual KWH consumption or average demand) is used to allocate part of the production plant costs among the classes, but part or all of these costs remain classified as demand-related. Such methods can be characterized as partial energy weighting methods in that they take the first step of allocating some portion of production plant costs to the classes on the basis of their energy loads but do not take the second step of classifying the costs as energy- related.

1. Average and Excess Method

Objective: The cost of service analyst may believe that average demand rather than coincident peak demand is a better allocator of production plant costs. The average and excess method is an appropriate method for the analyst to use. The method allocates production plant costs to rate classes using factors that combine the classes' average demands and non-coincident peak (NCP) demands.

Data Requirements: The required data are: the annual maximum and average demands for each customer class and the system load factor. All production plant costs are usually classified as demand-related. The allocation factor consists of two parts. The first component of each class's allocation factor is its proportion of total average demand (or energy consumption) times the system load factor. This effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor. The second component of each class's allocation factor is called the "excess demand factor." It is the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand. The difference may be negative for curtailable rate classes. This component is multiplied by the remaining proportion of production plant -- i.e., by 1 minus the system load factor -- and then added to the first component to obtain the "total allocator." Table 4-10A shows the derivation of the allocation factors and the resulting allocation of production plant costs using the average and excess method.

TABLE 4-10A

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

Class Rate	Demand Allocation Factor - NCP MW	Average Demand (MW)	Excess Demand (NCP MW - Avg. MW)	Average Demand Component of Alloc. Factor	Excess Demand Component of Alloc. Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	5,357	2,440	2,917	17.95	18.51	36.46	386,683,685
LSMP	5,062	2,669	2,393	19.64	15.18	34.82	369,289,317
LP	3,385	2,459	926	18.09	5.88	23.97	254,184,071
AG&P	572	254	318	1.87	2.02	3.89	41,218,363
SL	126	58	68	0.43	0.43	0.86	9,101,564
TOTAL	14,502	7,880	6,622	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows production plant classified as demand-related.

Some columns may not add to indicated totals due to rounding.

If your objective is -- as it should be using this method --to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincident peak allocation factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands.

The example on Table 4-10B illustrates this problem. In the example, the excess demand component of the allocation factor for the Street Lighting and Outdoor Lighting (SL/OL) class is negative and reduces the class's allocation factor to what it would be if a single CP method were used in the first place. (See third column of Table 4-3.)

TABLE 4-10B

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD (SINGLE CP DEMAND FACTOR)

Rate Class	Demand Allocation Factor - Single CP NCP MW	Average Demand (MW)	Excess Demand (Single CP MW - Avg. MW)	Average Demand Component of Allocation Factor	Excess Demand Component of Allocation Factor	Total Allocation Factor (%)	Class Production Plant Revenue Requirement
DOM	4,735	2,440	2,295	17.95	16.89	34.84	369,461,692
LSMP	5,062	2,669	2,393	19.64	17.61	37.25	394,976,787
LP	3,347	2,459	888	18.09	6.53	24.63	261,159,089
AG&P	447	254	193	1.87	1.42	3.29	34,878,432
SL	0	58	-58	0.43	-0.43	0.00	0
TOTAL	13,591	7,880	5,711	57.98	42.02	100.00	$1,060,476,000

Notes: The system load factor is 57.98 percent, calculated by dividing the average demand of 7,880 MW by the systen coincident peak demand of 13,591 MW. This example shows all production plant classified as demand-related. Note that the total allocation factors are exactly equal to those derived using the single coincident peak method shown in the third column of Table 4-3.

Some columns may not add to indicated totals due to rounding.

Some analysts argue that the percentage of total production plant that is equal to the system load factor percentage should be classified as energy-related and not demand-related. This could be important because, although classifying the system load factor percentage as energy-related might not affect the allocation among classes, it could significantly affect the apportionment of costs within rate classes. Such a classification could also affect the allocation of production plant costs to interruptible service, if the utility or the regulatory authority allocated energy-related production plant costs but not demand-related production plant costs to the interruptible class. Table 4-10C presents the allocation factors and production plant revenue requirement allocations for an average and excess cost of service study with the system load factor percentage classified as energy-related.

TABLE 4-10C

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE AVERAGE AND EXCESS METHOD

(AVERAGE DEMAND PROPORTION ALLOCATED ON ENERGY)

Rate Class	Energy Allocation Factor - Average MW	Energy Allocatn. Factor (%)	Energy-Related Production Plant Revenue Requirement	Excess Demand Allocation Factor (NCP MW - Avg. MW)	Excess Demand Alloctn. Factor (Percent)	Demand-Related Production Plant Revenue Requirement	Class Production Plant Revenue Requiremnt
DOM	2,440	30.96	190,387,863	2,917	44.05	196,294,822	386,682,685
LSMP	2,669	33.87	208,256,232	2,393	36.14	161,033,085	369,289,317
LP	2,459	31.21	191,870,391	926	13.98	62,313,680	254,184,071
AG&P	254	3.22	19,819,064	318	4.80	21,399,298	41,218,363
SL	58	0.74	4,525,613	68	1.03	4,575,951	9,101,564
TOTAL	7,880	100.00	614,859,163	6,622	100.00	445,616,837	1,060,476,000

Notes: The system load factor is 57.98 percent (7,880 MW/13,591 MW). Thus, 57.98 percent of total production plant revenue requirement is classified as energy-related and allocated to all classes on the basis of their proportions of average system demand. The remaining 42.02 percent is classified as demand-related and allocated to the classes according to their proportions of excess (NCP - average) demand, and allocated to the firm service classes according to their proportions of excess (NCP - average) demand.

Some columns may not add to indicated totals due to rounding.

2. Equivalent Peaker Methods

O***bjective:*** Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. They generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by pure peak demand responsibility methods.

The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.

Data Requirements: This energy weighting method takes a different tack toward production plant cost allocation, relying more heavily on system planning data in addition to load research data. The cost of service analyst must become familiar with system expansion criteria and justify his cost classification on system planning grounds.

A Digression on System Planning with Reference to Plant Cost Allocation:

Generally speaking, electric utilities conduct generation system planning by evaluating the need for additional capacity, then, having determined a need, choosing among the generation options available to it. These include purchases from a neighboring utility, the construction of its own peaking, intermediate or baseload capacity, load management, enhanced plant availability, and repowering among others.

The utility can choose to construct one of a variety of plant-types: combustion turbines (CT), which are the least costly per KW of installed capacity, combined cycle (CC) units costing two to three times as much per KW as the CT, and baseloaded units with a cost of four or more times as much as the CT per KW of installed capacity. The choice of unit depends on the energy load to be served. A peak load of relatively brief duration, for example, less than 1,500 hours per year, may be served most economically by a CT unit. A peak load of intermediate duration, of 1,500 to 4,000 hours per year, may be served most economically by a CC unit. A peak load of long annual duration may be served most economically by a baseload unit.

Classification of Generation:

In the equivalent peaker type of cost study, all costs of actual peakers are classified as demand-related, and other generating units must be analyzed carefully to determine their proportionate classifications between demand and energy. If the plant types are significantly different, then individual analysis and treatment may be necessary. The ideal analysis is a "date of service" analysis. The analyst calculates the installed cost of all units in the dollars of the install date and classifies the peaker cost as demand-related. The remaining costs are classified as energy-related.

A variant of the above approach is to do the equivalent peaker cost evaluations based only on the viable generation alternatives available to the utility at any point in time. For example, combined cycle technology might be so much more cost-effective than the next best option that it would be the preferred choice for demand lasting as little as 50 to 100 hours. If so, then using a combustion turbine as the equivalent peaker "benchmark" might be inappropriate. Such choices would require careful analysis of alternate generation expansion paths on a case by case basis.

Consider the example shown in Table 4-11. The example utility has three 100 MW combustion turbines of varying ages. All investment in these units is classified as demand-related. The utility also has three unscrubbed coal-fired units of varying ages. The production plant costs of these units are classified as follows: first, the ratio of the cost of a new CT ($300/KW) to the cost of a new unscrubbed coal unit ($1000/KW) is calculated and found to be 30 percent. Then, this factor is multiplied by the rate base for each plant, and the result is classified as demand-related, with the remainder classified as energy-related. The cost of the utility's new, scrubbed coal unit is classified by the same method. Since the unit cost is $1200/KW, only 25 percent of it ($300/KW)/($1200/KW) is classified as demand-related, with the remaining three-fourths classified as energy-related. Treating the utility's nuclear unit similarly, only 15 percent of its cost ($300/KW)/($2000/KW) is classified as demand-related.

TABLE 4-11
ILLUSTRATION OF DEMAND AND ENERGY AND ENERGY CLASSIFICATION OF GENERATING UNITS USING THE EQUIVALENT PEAKER METHOD

Unit	Unit Type	Capacity (MW)	Rate Base	Percent Class Demand-Related	Demand-Related Rate Base	Energy-Related Rate Base
A	CT	100	10,000,000	100	10,000,000	0
B	CT	100	20,000,000	100	20,000,000	0
C	CT	100	30,000,000	100	30,000,000	0
D	Coal	200	80,000,000	30	24,000,000	56,000,000
E	Coal	250	100,000,000	30	30,000,000	70,000,000
F	Coal	450	270,000,000	30	81,000,000	189,000,000
G	Coal W/FDG	600	720,000,000	25	180,000,000	540,000,000
H	Nuclear	900	1,800,000,000	15	270,000,000	1,530,000,000
TOTAL		2,700	$ 3,030,000,000	21	$ 645,000,000	$ 2,385,000,000

The equivalent peaker classification method applied in the example above ignores the fuel savings that accrue from running a base unit rather than a peaker. Discussions with planners can help incorporate the effects of fuel savings into the classification.

Table 4-12 shows the revenue responsibility for the rate classes using the equivalent peaker cost method applied to the example utility's data. In this example, a summer and winter peak demand allocator was used to allocate the demand-related costs. Observe that the total revenue requirement allocation among the rate classes is significantly different from that resulting from any of the pure peak demand responsibility methods.

TABLE 4-12

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE EQUIVALENT PEAKER COST METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requiremnt
DOM	36.67	78,980,827	30.96	261,678,643	340,659,471
LSMP	35.50	76,460,850	33.87	286,237,828	362,698,678
LP	25.14	54,147,205	31.21	263,716,305	317,863,510
AG&P	2.22	4,781,495	3.22	27,240,318	32,021,813
SL	0.47	1,012,299	0.74	6,220,230	7,232,529
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

3. Base and Peak Method

Objective: The objective of the base and peak method is to reflect in cost allocation the argument that an on-peak kilowatt-hour costs more than an off-peak kilowatt-hour and that the extra cost should be borne by the customers imposing it. This approach first identifies the same production plant cost components as the equivalent peaker cost method, and allocates demand-related production plant costs in the same way. The difference is that, using the base and peak method, the energy-related excess capital costs are allocated on the basis of the classes' proportions of on-peak energy use instead of being allocated according to the classes' shares of total system energy use. The logic of this approach is that the extra capital costs would be incurred once the system was expected to run for a certain minimum number of hours; i.e., once the break-even point in unit run time between a peaker and a baseload (or intermediate) unit was reached. However, system planners generally recognize no difference between on-peak hours and off-peak energy loads on the decision to build a baseload power plant, instead, the belief is that system planners consider the total annual energy loads that determine the type of plant to build. To allocate energy-related production plant costs on the basis of only on-peak energy use implies a differential impact of on-peak KWH as compared to off-peak KWH that may or may not exist.

Table 4-13 shows the results of a base and peak cost of service method for the example utility.

TABLE 4-13

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE BASE AND PEAK METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor On-Peak MWH	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	78,980,827	32.13	271,541,532	350,522,360
LSMP	35.50	76,460,850	36.21	306,044,166	382,505,016
LP	25.14	54,147,205	28.26	238,860,669	293,007,874
AG&P	2.22	4,781,495	2.73	23,086,785	27,868,280
SL	0.47	1,012,299	0.66	5,560,171	6,572,470
TOTAL	100.00	215,382,676	100.00	845,093,324	$1,060,476,000

Note: Some columns may not add to indicated totals due to rounding.

4. Judgmental Energy Weightings

Some regulatory commissions, recognizing that energy loads are an important determinant of production plant costs, require the incorporation of judgmentally-established energy weighting into cost studies. One example is the "peak and average demand" allocator derived by adding together each class's contribution to the system peak demand (or to a specified group of system peak demands; e.g., the 12 monthly CPs) and its average demand. The allocator is effectively the average of the two numbers: class CP (however measured) and class average demand. Two variants of this allocation method are shown in Tables 4-14 and 4-15.

TABLE 4-14

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 1 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 1 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Avg. Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	34.84	233,869,251	30.96	120,512,062	354,381,313
LSMP	37.25	250,020,306	33.87	131,822,415	381,842,722
LP	24.63	165,313,703	31.21	121,450,476	286,764,179
AG&P	3.29	22,078,048	3.22	12,545,108	34,623,156
SL	0.00	0	0.74	2,864,631	2,864,631
TOTAL	100.00	671,281,308	100.00	389,194,692	$1,060,476,000

Notes: The portion of the production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of (a) the annual system peak demand, Table 4-3, column 2, plus (b) the average system demand for the test year, Table 4-10A, column 3. Thus, the percentage classified as demand-related is equal to 13591/(13591+7880), or 63.30 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the system peak demand and the average system demand. For the example, this percentage is 36.70 percent.

Some columns may not add to indicated totals due to rounding.

TABLE 4-15

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND AVERAGE DEMAND METHOD

Rate Class	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	198,081,400	30.96	137,226,133	335,307,533
LSMP	38.43	237,225,254	33.87	150,105,143	387,330,397
LP	26.71	164,899,110	31.21	138,294,697	303,193,807
AG&P	2.42	14,960,151	3.22	14,285,015	29,245,167
SL	0.35	2,137,164	0.74	3,261,933	5,399,097
TOTAL	100.00	617,303,080	100.00	443,172,920	$1,060,476,000

Notes: The portion of production plant classified as demand-related is calculated by dividing the annual system peak demand by the sum of the 12 monthly system coincident peaks (Table 4-3, column 4) by the sum of that value plus the system average demand (Table 4-10A, column 3). Thus, for example, the percentage classified as demand-related is equal to 10976/(10976+7880), or 58.21 percent. The percentage classified as energy-related is calculated similarly by dividing the average demand by the sum of the average demand and the average of the twelve monthly peak demands. For the example, 41.79 percent of production plant revenue requirements are classified as energy-related.

Another variant of the peak and average demand method bases the production plant cost allocators on the 12 monthly CPs and average demand, with 1/13th of production plant classified as energy-related and allocated on the basis of the classes' KWH use or average demand, and the remaining 12/13ths classified as demand-related. The resulting allocation factors and allocations of revenue responsibility are shown in Table 4-16 for the example data.

TABLE 4-16

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING THE 12 CP AND 1/13TH WEIGHTED AVERAGE DEMAND METHOD

Rate	Demand Allocation Factor - 12 CP MW (Percent)	Demand-Related Production Plant Revenue Requirement	Average Demand (Total MWH) Allocation Factor	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	32.09	314,111,612	30.96	25,259,288	339,370,900
LSMP	38.43	376,184,775	33.87	27,629,934	403,814,709
LP	26.71	261,492,120	31.21	25,455,979	286,948,099
AG&P	2.42	23,723,364	3.22	2,629,450	26,352,815
SL	0.35	3,389,052	0.74	600,426	3,989,478
TOTAL	100.00	978,900,923	100.00	81,575,077	$1,060,476,000

Notes: Using this method, 12/13ths (92.31 percent) of production plant revenue requirement is classified as demand-related and allocated using the 12 CP allocation factor, and 1/13th (7.69 percent) is classified as energy-related and allocated on the basis of total energy consumption or average demand.

Some columns may not add to indicated totals due to rounding.

C. Time-Differentiated Embedded Cost of Service Methods

Time-differentiated cost of service methods allocate production plant costs to baseload and peak hours, and perhaps to intermediate hours. These cost of service methods can also be easily used to allocate production plant costs to classes without specifically identifying allocation to time periods. Methods discussed briefly here include production stacking methods, system planning approaches, the base-intermediate-peak method, the LOLP production cost method, and the probability of dispatch method.

1. Production Stacking Methods

Objective: The cost of service analyst can use production stacking methods to determine the amount of production plant costs to classify as energy-related and to determine appropriate cost allocations to on-peak and off-peak periods. The basic principle of such methods is to identify the configuration of generating plants that would be used to serve some specified base level of load to classify the costs associated with those units as energy-related. The choice of the base level of load is crucial because it determines the amount of production plant cost to classify as energy-related. Various base load level options are available: average annual load, minimum annual load, average off-peak load, and maximum off-peak load.

Implementation: In performing a cost of service study using this approach, the first step is to determine what load level the "production stack" of baseload generating units is to serve. Next, identify the revenue requirements associated with these units. These are classified as energy-related and allocated according to the classes' energy use. If the cost of service study is being used to develop time-differentiated costs and rates, it will be necessary to allocate the production plant costs of the baseload units first to time periods and then to classes based on their energy consumption in the respective time periods. The remaining production plant costs are classified as demand-related and allocated to the classes using a factor appropriate for the given utility.

An example of a production stack cost of service study is presented in Table 4-17. This particular method simply identified the utility's nuclear, coal-fired and hydroelectric generating units as the production stack to be classified as energy-related. The rationale for this approach is that these are truly baseload units. Additionally, the combined capacity of these units (4,920.7 MW) is significantly less than either the utility's average demand (7,880 MW) or its average off-peak demand (7,525.5 MW); thus, to get up to the utility's average off-peak demand would have required adding oil and gas-fired units, which generally are not regarded as baseload units. This method results in 89.72 percent of production plant being classified as energy-related and 10.28 percent as demand-related. The allocation factor and the classes' revenue responsibility are shown in Table 4-17.

2. Base-Intermediate-Peak (BIP) Method

The BIP method is a time-differentiated method that assigns production plant costs to three rating periods: (1) peak hours, (2) secondary peak (intermediate, or shoulder hours) and (3) base loading hours. This method is based on the concept that specific utility system generation resources can be assigned in the cost of service analysis as serving different components of load; i.e., the base, intermediate and peak load components. In the analysis, units are ranked from lowest to highest operating costs. Those with the lower operating costs are assigned to all three periods, those with intermediate running costs are assigned to the intermediate and peak periods, and those with the highest operating costs are assigned to the peak rating period only.

TABLE 4-17

CLASS ALLOCATION FACTORS AND ALLOCATED PRODUCTION PLANT REVENUE REQUIREMENT USING A PRODUCTION STACKING METHOD

Rate Class	Demand Allocation Factor - 3 Summer & 3 Winter Peaks (%)	Demand-Related Production Plant Revenue Requirement	Energy Allocation Factor (Total MWH)	Energy-Related Production Plant Revenue Requirement	Total Class Production Plant Revenue Requirement
DOM	36.67	39,976,509	30.96	294,614,229	334,590,738
LSMP	35.50	38,701,011	33.87	322,264,499	360,965,510
LP	25.14	27,406,857	31.21	296,908,356	324,315,213
AG&P	2.22	2,420,176	3.22	30,668,858	33,089,034
SL	0.47	512,380	0.74	7,003,125	7,515,505
TOTAL	100.00	109,016,933	100.00	951,459,067	$1,060,476,000

Note: This allocation method uses the same allocation factors as the equivalent peaker cost method illustrated in Table 4-12. The difference between the two studies is in the proportions of production plant classified as demand- and energy-related. In the method illustrated here, the utility's identified baseload generating units -- its nuclear, coal-fired and hydroelectric generating units -- were classified as energy-related, and the remaining units -- the utility's oil- and gas-fired steam units, its combined cycle units and its combustion turbines -- were classified as demand-related. The result was that 89.72 percent of the utility's production plant revenue requirement was classified as energy-related and allocated on the basis of the classes' energy consumption, and 10.28 percent was classified as demand-related and allocated on the basis of the classes' contributions to the 3 summer and 3 winter peaks.

Some columns may not add to indicated totals due to rounding

There are several methods that may be used for allocating these categorized costs to customer classes. One common allocation method is as follows: (1) peak production plant costs are allocated using an appropriate coincident peak allocation factor; (2) intermediate production plant costs are allocated using an allocator based on the classes' contributions to demand in the intermediate or shoulder period; and (3) base load production plant costs are allocated using the classes' average demands for the base or off-peak rating period.

In a BIP study, production plant costs may be classified as energy-related or demand-related. If the analyst believes that the classes' energy loads or off-peak average demands are the primary determinants of baseload production plant costs, as indicated by the inter-class allocation of these costs, then they should also be classified as energy-related and recovered via an energy charge. Failure to do so -- i.e., classifying production plant costs as demand-related and recovering them through a $/KW demand charge -- will result in a disproportionate assignment of costs to low load factor customers within classes, inconsistent with the basic premise of the method.

3. LOLP Production Cost Method

LOLP is the acronym for loss of load probability, a measure of the expected value of the frequency with which a loss of load due to insufficient generating capacity will occur. Using the LOLP production cost method, hourly LOLP's are calculated and the hours are grouped into on-peak, off-peak and shoulder periods based on the similarity of the LOLP values. Production plant costs are allocated to rating periods according to the relative proportions of LOLP's occurring in each. Production plant costs are then allocated to classes using appropriate allocation factors for each of the three rating periods; i.e., such factors as might be used in a BIP study as discussed above. This method requires detailed analysis of hourly LOLP values and a significant data manipulation effort.

4. Probability of Dispatch Method

The probability of dispatch (POD) method is primarily a tool for analyzing cost of service by time periods. The method requires analyzing an actual or estimated hourly load curve for the utility and identifying the generating units that would normally be used to serve each hourly load. The annual revenue requirement of each generating unit is divided by the number of hours in the year that it operates, and that "per hour cost" is assigned to each hour that it runs. In allocating production plant costs to classes, the total cost for all units for each hour is allocated to the classes according to the KWH use in each hour. The total production plant cost allocated to each class is then obtained by summing the hourly cost over all hours of the year. These costs may then be recovered via an appropriate combination of demand and energy charges. It must be noted that this method has substantial input data and analysis requirements that may make it prohibitively expensive for utilities that do not develop and maintain the required data.

TABLE 4-18

SUMMARY OF PRODUCTION PLANT COST ALLOCATIONS USING DIFFERENT COST OF SERVICE METHODS

	1 CP METHOD		12 CP METHOD		3 SUMMER & 3 WINTER PEAK METHOD		ALL PEAK HOURS APPROACH		AVERAGE AND EXCESS METHOD	
	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 369,461,692	34.84	$ 340,287,579	32.09	$ 388,925,712	36.67	$ 340,747,311	32.13	$ 386,682,685	36,46
LSMP	394,976,787	37.25	407,533,507	38.43	376,433,254	35.50	384,043,376	36.21	369,289,317	34.82
LP	261,159,089	24.63	283,283,130	26.71	266,582,600	25.14	299,737,319	28.26	254,184,071	23.97
AG&P	34,878,432	3.29	25,700,311	2.42	23,555,089	2.22	28,970,743	2.73	41,218,363	3.89
SL	0	0.00	3,671,473	0.35	4,978,544	0.47	6,977,251	0.66	9,101,564	0.86
Total	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.00	$1,060,476,000	100.0	$1,060,476,000	100.0

	EQUIVALENT PEAKER COST METHOD		BASE AND PEAK METHOD		1 CP AND AVERAGE DEMAND METHOD		12 CP AND 1/13th AVERAGE DEMAND METHOD		PRODUCTION STACKING METHOD	
Rate Class	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total	Revenue Req't. ($)	Percent of Total
DOM	$ 340,657,471	32.12	$ 3350,522,360	33.05	$ 354,381,313	33.42	$ 339,370,900	32.00	$ 334,590,738	31.55
LSMP	362,698,678	34.20	382,505,016	36.07	381,842,722	36.01	403,814,709	38.08	360,965,510	34.04
LP	317,863,510	29.97	293,007,874	27.63	286,764,179	27.04	286,948,099	27.06	324,315,213	30.58
AG&P	32,021,813	3.02	27,868,280	2.63	34,623,156	3.36	26,352,815	2.48	33,089,034	3.12
SL	7,232,529	0.68	6,572,470	0.62	2,864,631	0.27	3,989,478	0.38	7,515,505	0.71
Total	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00	$1,060,476,000	100.00

5. Summary

Table 4-18 summarizes the percentage allocation factors and revenue allocations for the cost of service methodologies presented in this chapter. Important observations are: (1) that the proportions of production plant costs classified as demand-related and energy-related can have dramatic effects on the revenue allocation; and (2) the greater the proportion classified as energy-related, the greater is the revenue responsibility of high load factor classes and the less is the revenue responsibility of low-load factor classes.

V. FUEL EXPENSE DATA

Fuel expense data can be obtained from the FERC Form 1. Aggregate fuel expense data by generation type is found in Accounts 501, 518, and 547. Annual fuel expense by fuel type for specified generating stations can be found on pages 402 and 411 of Form 1.

Fuel expense is almost always classified as energy-related. It is allocated using appropriate time-differentiated allocators; e.g., on-peak KWH and off-peak KWH, or non-time-differentiated energy allocators (total KWH) calculated by incorporating adjustments to reflect different line and transformation losses at different levels of the utility's transmission and distribution system. Depending on the cost of service method used, it may be necessary to directly assign fuel expense to classes that are directly assigned the cost responsibility for specific generating units. Table 4-19 shows the allocation of fuel expense, other operation and maintenance expenses and purchased power expenses for the example utility. Fuel and purchased power expenses were allocated according to the classes' energy use at the generator level. Other operation and maintenance expenses were allocated using demand and energy allocators and ratio methods.

VI. OTHER OPERATIONS AND MAINTENANCE EXPENSES FOR PRODUCTION

Other production O&M costs may also be classified as demand-related or energy-related. Typically, any costs that vary directly with the amount of energy produced, such as purchased steam, variable water cost and water treatment chemical costs, are classified as energy-related and allocated using appropriate energy allocation factors. Such cost items would typically be booked in Accounts 502 through 505 for fossil power steam generation, Accounts 519 and 520 for nuclear power generation, and Accounts 548 and 550.1 for other generation (excluding hydroelectric).

TABLE 4-19
ALLOCATED GENERATION FUEL, OPERATION, AND MAINTENANCE EXPENSES
(Thousands of Dollars)

EXPENSE CATEGORY	TOTAL COMPANY RETAIL	DOMESTIC	LIGHTING, SMALL AND MEDIUM POWER	LARGE POWER	AGRICULTURAL AND PUMPING	STREET LIGHTING
Total Fuel	$ 871,598	$269,887	$295,147	$272,028	$28,068	$ 6,467
Steam Generation Expenses						
Operation Expenses	53,740	17,246	20,652	14,355	1,301	186
Maintenance Expenses	176,117	54,632	60,037	54,574	5,601	1,272
Total Steam Excl. Fuel	229,857	71,879	80,688	68,929	6,902	1,459
Nuclear Generation Expenses						
Operation Expenses	106,851	34,291	41,061	28,541	2,587	371
Maintenance Expenses	88,787	27,552	30,305	27,475	2,817	638
Total Nuclear Excl. Fuel	195,638	61,842	71,366	56,017	5,404	1,009
Hydraulic Generation Expenses						
Operation Expenses	9,730	3,054	3,462	2,872	284	58
Maintenance Expenses	13,135	4,123	4,674	3,877	383	78
Total Hydraulic Expenses	22,865	7,177	8,136	6,749	667	136
Other Generation Expenses						
Operation Expenses	20,461	6,563	7,953	5,358	516	70
Maintenance Expenses	10,371	3,327	4,020	2,729	259	36
Total Other Excl. Fuel	30,832	9,890	11,973	8,087	775	106
Purchased Power	1,275,663	395,005	431,975	398,138	41,080	9,466
System Control & Dispatch	0	0	0	0	0	0
Other	0	0	0	0	0	0
Total	$2,626,453	$815,680	$899,285	$809,948	$82,896	$18,643

Note: Some values may not add to indicated totals or sub-totals due to rounding.

Operations and maintenance costs that do not vary directly with energy output may be classified and allocated by different methods. If certain costs are specifically related to serving particular rate classes, they are directly assigned. Some accounts may be easily identified as being all demand-related or all energy-related; these may then be allocated using appropriate demand andenergy allocators. Other accounts contain both demand-related and energy-related components. One common method for handling such accounts is to separate the labor expenses from the materials expenses: labor costs are then considered fixed and therefore demand-related, and materials costs are considered variable and thus energy-related. Another common method is to classify each account according to its "predominant" -- i.e., demand-related or energy-related -- character. Certain supervision and engineering expenses can be classified on the basis of the prior classification of O&M accounts to which these overhead accounts are related. Although not standard practice, O&M expenses may also be classified and allocated as the generating plants at which they are incurred are allocated.

VII. SUMMARY AND CONCLUSION

A. Choosing a Production Cost Allocation Method

As we have seen in the catalog of cost allocation methods above, the analyst chooses a method after considering many complex factors: (1) the utility's generation system planning and operation; (2) the cost of serving load with new generation or purchased power; (3) the incidence of new load on an annual, monthly and hourly basis; (4) the availability of load and operations data; and (5) the rate design objectives.

B. Data Needs and Sources

Most of the cost of service methods reviewed above require: (1) rate base data; (2) operations and maintenance expense data, depreciation expense data, and tax data; and (3) peak demand and energy consumption data for all rate classes. Some methods also require information from the utility's system planners regarding the operation of specific generating units and more general data such as generation mix, types of plants and the plant loading; for example, how often the units are operated, and whether they are run as baseload, intermediate or peaking units. Rate base, O&M, depreciation, tax and revenue data are generally available from the FERC Form 1 reports that follow the uniform system of accounts prescribed by FERC for utilities (18 CFR Chapter 1, Subchapter C, Part 101). See Chapter 3 for a complete discussion of revenue requirements. Load data may be gathered by the utility or borrowed from similar neighboring utilities if necessary. Data or information relating to specific generating units must be obtained from the utility's system planners and power-system operators.

C. Class Load Data

Any cost of service method that allocates part or all of production plant costs using a peak demand allocator requires at least estimates of the classes' peak demands. These may be estimates of the classes' coincident peak (CP) or non-coincident class peak (NCP) demands.

For larger utilities, class load data is generally developed from statistical samples of customers with time-recording demand and energy meters. Utilities without a load research program can sometimes borrow load data from others. See Appendix A for a thorough discussion of development of data through load research studies.

Different cost of service methods have different data requirements. The requirements may be as simple as: (1) total energy usage, adjusted for different line and transformation losses to be comparable at the generation level; (2) the class coincident peak demands in the peak hour of the year; and (3) the class non-coincident peak demands for the year. Some methods require much more complex data, ranging from class CP demands in each of the 12 monthly peak hours to estimated class demands in each hour of the year. Thus, load data development and analysis for cost of service studies entail substantial effort and cost.

D. System and Unit Dispatch Data

Some methods, such as the base-intermediate-peak methods, require classification of units according to their primary operating function. This may involve judgmental classification by system planners or power system operators. Other methods, such as the probability of dispatch methods, require either actual or modeled data regarding specific units' operation on an hour-by-hour basis, as well as hourly load data. Production stacking methods require data on the dispatch configuration of units, including reserves, required to serve a given load level. Such data must be developed and maintained by the utility.

E. Conclusion

This review of production cost allocation methods may not contain every method, but it is hoped that the reader will agree that the broad outlines of all methods are here. The possibilities for varying the methods are numerous and should suit the analysts' assessment of allocation objectives. Keep in mind that no method is prescribed by regulators to be followed exactly; an agreed upon method can be revised to reflect new technology, new rate design objectives, new information or a new analyst with new ideas. These methods are laid out here to reveal their flexibility; they can be seen as maps and the road you take is the one that best suits you.

CHAPTER 5

FUNCTIONALIZATION AND ALLOCATION OF TRANSMISSION PLANT

The transmission system may be defined for ratemaking purposes as a group of highly integrated bulk power supply facilities, con-sisting of high voltage power lines and substations. They are designed and operated by a utility to transport electric power reliably and economically from points of origin on its system to distribution loads or load centers located within its franchise area, or to other points of delivery on its system[1]. The points of origin of power so transported may be from the utility's own production resources, or may be that of another utility which is then delivered by that utility to the other's system through various transmission interconnections. The transmission function is generally concluded at the high-voltage side of a distribution substation owned by the utility, or at points where the ownership of bulk power supply facilities change.

The two principal characteristics that distinguish one transmission system from another are the voltages at which the bulk power supply facilities are designed and operated, and the way in which those facilities are configured.

The voltages of transmission facilities can and do vary widely from one electric system to another. For example, where one system's predominant backbone transmission facilities may consist of 345KV or higher voltage facilities, another's may consist of 115KV facilities, while still another's may have a combination of facilities which operate at various transmission voltages.

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[1]The Federal Energy Regulatory Commission defines a transmission system to include: (1) all land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchase power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; (2) all land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and (3) all lines and equipment whose primary pupose is to augment, integrate or tie together the sources of power supply. (1 FERC Para, 15,064).

The way in which transmission facilities are configured also varies widely from system to system. For example, some systems may be highly integrated, where facilities of the same or different voltages are configured to form networks that provide a number of alternative paths through which power may flow from one point to another. Other systems may be essentially radial, where few or no alternative paths exist to transport power from one point to another.

In general, the transmission system may be considered to be comprised of a number of subsystems, or component parts, which operate together to deliver bulk power supply to various points or load centers. The most commonly used terms to differentiate the various subsystems from each other are: (1) the backbone and inter-tie facilities; (2) generation step-up facilities; (3) subtransmission plant; and (4) radial facilities.

In addition, there are other plant components that may perform a function not perceived as being predominately related to transmission, but nonetheless contributing to the economic and reliable operation of the transmission system. In a cost of service format, these particular plant facilities, which are represented as investment costs recorded in a utility's production or distribution plant accounts, are often referred to as "plant reclassifications."

The use of transmission subsystems is both a useful means of generally explaining the different aspects of transmission system design and operation, and is particularly applicable to the ratemaking process. For example, where certain classes of electric utility customers require service from the transmission system as a whole, other classes may not require the use of all components of the system. Thus, the use of subsystems or plant groupings provides the basis upon which cost responsibilities among customer groups may be differentiated.

This chapter first discusses two methods of transmission system functionalization; with more detailed attention paid to subfunctionalization methods. Next, several methods used to allocate transmission plant costs are presented. The careful reader will see similarities with Chapter 4. Finally, the treatment of wheeling costs is discussed.

I. FUNCTIONALIZATION OF THE TRANSMISSION SYSTEM

Functionalization may be defined as the process of grouping costs associated with a facility that performs a certain function with the costs of other facilities that perform similar functions. The extent to which transmission plant is functionalized in a cost of service analysis will usually depend upon the design and operating characteristics of classes of facilities, their different cost characteristics, and the type and nature of electric services being provided by the utility.

The process of transmission plant functionalization usually begins with the identification and grouping of those higher-order customers, and concludes with those groups of facilities of a lesser order that are required to serve only particular customers or groups of customers.

The number of transmission plant cost groups can range from one to several. Where only one transmission cost group is recognized, the functionalization method is referred to as the "rolled-in method." Where more than one group of transmission facilities is recognized, the functionalization method is usually called the "subfunctionalization method."

A. The Rolled-in Transmission Plant Method

Under the rolled-in transmission method of functionalization, the transmission system is comprised of highly integrated facilities which are designed and operated collectively to deliver bulk power supply from point to point on the system. Thus, where facilities of various operating voltages form integrated transmission networks, each element within those networks is considered to be contributing to the economic and reliable operation of the overall system.

While the concept of a fully integrated transmission system is the principal reason for treating it as a single system for ratemaking purposes, there are certain transmission facilities that are not integrated. These facilities, principally radial transmission lines, are used exclusively to serve specific customer loads at transmission voltages. The philosophy for rolling-in these radial lines is that they represent a short-term strategy in which a utility is able to maximize long-term system efficiency, without sacrificing reliability, by phasing-in transmission system expansions. In effect, radial transmission lines are perceived as the initial phase of transmission expansion from which network or looped facilities will ultimately emerge as system loads begin to grow. Therefore, since all customers are generally expected to benefit from the strategy of overall transmission cost minimization, all should be expected to share the costs of the system.

B. The Subfunctionalized Transmission Plant Method

The main alternative method to the rolled-in approach is the subfunctionalization of the transmission system. Under this approach, transmission subsystems may be distinguished from one another by the utility's use of them, or, on the basis of line configuration, geographic circumstances and voltage level, among other considerations.

The data requirements imposed by subfunctionalization are substantially more demanding than those imposed by the rolled-in method. Not only are detailed plant account records and schematic diagrams required to evaluate the function or role performed by each transmission element, but a high degree of subjective judgment is required to categorize these elements when their function is less than clear, or where an element performs multiple functions. For example, substation structures may house integrated transmission plant components that require the use of micro-allocation methods to apportion investment costs among all the subfunctionalized plant categories. In order to perform such micro-allocations, detailed plant cost accounting data as well as facility demand data must be available.

In addition, subfunctionalization gives rise to questions concerning the manner in which facilities of different vintages should be accounted for in the cost of service analysis. For example, subtransmission investment of early vintage is more depreciated than other subsystems within the transmission system. In order to recognize any vintage difference in the functionalization of depreciation reserve, a detailed review of a utility's historic plant accounting records will need to be undertaken.

Because of these substantial requirements, the extent to which transmission plant is to be functionalized should be limited to the number of plant categories that adequately recognize the different cost consequences that may exist among customers or groups of customers.

Under subfunctionalization, the main distinction is usually between those facilities that interconnect all the major power sources with each other -- the backbone transmission facilities -- and everything else. Utilities have identified subsystems such as generation step-up facilities, system interconnection and subtransmission, among others. These transmission system components and other non-backbone facilities may often be considered as a separate network of facilities that are either not used to support the backbone system, or represent facilities that require special recognition in the ratemaking process.

1. Backbone and Inter-tie Transmission Facilities

Backbone and inter-tie transmission facilities are generally considered to be the network of high-voltage facilities through which a utility's major production sources, both on and off its system, are integrated. As power systems have expanded to meet increased demands for electric energy, lower voltage networks have been overlaid with higher voltage transmission facilities to improve transmission system reliability and to capture economy benefits. Today, 115KV to 765KV (and even higher) voltage facilities constitute the backbone of most large transmission systems or power pools. Where a utility is a member of a formal power pool, through which reliability and economy gains may be realized from coordinated utility operations, it is not unusual that segments of an area-wide EHV backbone transmission network will be owned by several different utilities consistent with their pool obligations. The points at which ownership changes between utilities are often referred to as the pool inter-ties or interconnection points. Power flows in either direction over these inter-ties as a result of the coordinated operations of the interconnected utility members. This classification of transmission plant investment becomes significant in utility cost allocation studies where loads are served exclusively from the high voltage transmission network without appreciable support from the lower voltage networks. These facilities are generally allocated to all classes of firm power customers.

2. Generation Step-Up Facilities

Generation step-up facilities generally refer to the substations through which power is transformed from a utility's generation output voltages to its various transmission voltages. This classification is based on the concept that such facilities are an extension of production plant and should be treated accordingly, particularly where wheeling services are directly or indirectly involved in the cost allocations. Under this theory, all classes of firm load are generally allocated generation step-up costs except wheeling customers.

3. Subtransmission Plant

Subtransmission plant refers to those lower voltage facilities on some utilities' systems whose function, over time, has changed to a quasi-transmission role in the delivery of electric power supply. As generation station sites become further removed from the utility's loads, the character of the transmission system has significantly changed. Today, facilities operating at voltages of 115 KV or higher are considered to be transmission, while facilities operating at voltages below 25 KV are generally considered to be distribution. Those facilities operating at voltages between 25 KV and 115 volts are now commonly referred to as subtransmission facilities. Accordingly, subtransmission may be defined to represent that portion of utility plant used for the purpose of transferring electric energy from convenient points on a utility's backbone transmission system to its distribution system, or to other utility systems, such as points of interconnection with wholesale customers' facilities. Cost responsibility for subtransmission plant is usually assigned to only those loads served directly at the subtransmission voltages and those distribution loads fed through subtransmission facilities. Customers served at voltages higher than subtransmission are not allocated these costs on the theory that the subtransmission facilities are not required or used to provide the higher voltage services.

4. Radial Facilities

Radial transmission facilities represent those facilities that are not networked with other transmission facilities, but are used to serve specific loads directly. For cost of service purposes, these facilities may be directly assigned to specific customers on the theory that these facilities are not used or useful in providing service to customers not directly connected to them.

5. Plant Reclassifications

In some instances, distribution line and substation investments recorded in the distribution plant accounts may be reassigned to transmission because of their functional characteristics. An example of this is when a power generator is not directly interconnected with the transmission system but feeds directly into the distribution system. This could occur when a combustion turbine generator is located within a distribution load center. In this case, distribution facilities which provide the shortest path from the generator to the transmission system may be considered for reassignment to the transmission function on the theory that these facilities represent an integral part of the power supply network. The advent of cogeneration has added significantly to the importance of this reclassification because, in many cases, a cogenerator is connected to a utility's electrical system at a distribution voltage.

In other instances, large capacitor banks and synchronous condensers located within the distribution system may also be considered part of the transmission system. Synchronous condensers and capacitor banks generate volt-amperes reactives (VAR's) which feed into the transmission system and help stabilize transmission voltages and improve system power factor. The installation of large capacitor banks on the transmission system can cost as much as three times more per VAR than if they were installed at the distribution level. Thus, even though large capacitor banks and synchronous condensers have a significant influence in the operation of the transmission system, they are often installed at the distribution level to save in installation costs. In some cases where synchronous condensers are installed at the distribution level and are assigned to the transmission function, the shortest distribution path from these facilities to the transmission system as well as the condensers themselves may also be assigned to the transmission function.

II. METHODS OF ALLOCATING TRANSMISSION PLANT

A utility keeps track of its transmission plant costs in a manner suitable for ratemaking purposes in order to charge customers a cost-based rate for providing them with transmission services. These costs may be rolled-in or subfunctionalized to effect the appropriate assignment of costs based on the contribution of each customer group to the applicable plant cost category.

Costs are assigned using one of two general principles: (1) allocation; or (2) direct assignment. Allocation is an indirect method of cost assignment under which customer cost responsibilities are usually measured in terms of usages, e.g., KW, KWH or KVA. The premise of cost allocation is that the cost of providing transmission service to a customer is proportional to the demand that customer imposes on the system or its components. There are several methods discussed below to calculate these relationships. Direct assignment, as its name implies, rests on the premise that, insofar as facilities are used exclusively by a customer, the costs of those facilities can be imposed directly on that customer.

After transmission costs are separated into appropriate demand or energy allocation categories, it is necessary to then select a method of assigning cost allocation responsibility to various customers. In general, customers are allocated a portion of the fully distributed (embedded) cost of the transmission system on a basis similar to the way production costs are allocated. The reason for this is that the transmission system is essentially considered to be an extension of the production system, where the planning and operation of one is inexorably linked to the other. Thus, the major factors that drive production costs, it is argued, tend to drive transmission costs as well.

On the other hand, the transmission system is designed to reliably and economically deliver bulk power supply throughout the system, even under adverse operating conditions. In transmission contingency planning, the keystone to reliability is redundancy which translates, in effect, to capacity being built in excess of that which is minimally required to deliver load. The redundant character of the transmission system then gives rise to the theory that its capacity is separable into two functional components: (1) an energy-delivery system component, allocable on an energy basis; and (2) a reliability component, allocable on the basis of some demand or capacity measurement. This particular approach, however, is not in common usage.

Customer transmission cost responsibility in the cost of service is expressed in terms of allocation ratios. These ratios are usually developed on the basis of customer demands to the sum of all demands deemed to be imposed on the total system or subsystem. Thus, the demand of the customer is included in both the numerator and denominator of the allocation factor and the customer is accordingly allocated a portion of the total costs. Since firm power loads are the highest order of electric service, all fixed costs are deemed incurred to provide such service. Conversely, non-firm service may either be opportunity-type sales without availability assurances, or sales from surplus capacity with limited assurances of availability. Thus, revenues derived from these sales, usually based on negotiated rates, may recover costs anywhere in the range of zero to the amount of the fully distributed costs. With value of service negotiated prices, revenues may even exceed fully distributed costs. In recognition of this cost or price flexibility, the demands for non-firm customers are usually excluded from the allocation factor determinations and, concomitantly, the revenues collected from non-firm customers are treated as credits in the cost of service.

Numerical examples for several allocation methods are provided with data contained in Table 5-1.

TABLE 5-1

1988 SYSTEM AND CUSTOMER DATA - TRANSMISSION LEVEL

	SYSTEM			CUSTOMER GROUP		
Month	KWH (millions)[1]	CP Demand (MW)[1]	NCP Demand (MW)[2]	CP Demand (MW)[1]	NCP Demand (MW)[1]	KWH (millions)[3]
Jan	5610	10520	11074	337	319	166
Feb	5130	10570	11126	344	315	153
Mar	5590	10180	10716	354	344	179
Apr	5400	10620	11178	361	358	180
May	5670	11190	11779	410	403	210
Jun	5860	12090	12726	431	427	215
Jul	6580	13730	14453	524	515	268
Aug	6910	14610	15379	524	520	271
Sep	6410	15050	15842	491	489	246
Oct	6110	12380	13032	405	405	211
Nov	5500	10770	11337	364	336	169
Dec	5700	11120	11705	355	347	181
Total	70470	142830	150347	4900	4778	2449

[1] Basic data supplied by Southern California Edison Company.

[2] Assuming .95 coincidence factor.

[3] Assuming 70% monthly load factor.

A. Allocation Methods

1. The Single System Coincident Peak (1CP) Demand Allocation Method

The single highest peak demand is the overriding consideration that drives power supply cost decisions. Customer contribution to this single annual system peak is used to measure customer responsibility. The result is that those customers which most heavily contribute to the single monthly peak will pay a proportionally larger amount of the cost of maintaining the transmission system.

The calculation of the 1CP demand allocation requires a knowledge of the company's single transmission system peak demand (exclusive of non-firm demands) and the demand of the customer group at the same hour and day of that month. The 1CP demand allocation ratio is computed by dividing the customer group's 1CP demand by the utility's transmission demand at the time of the system peak, as follows:

$$\text{1CP Customer Group Demand Ratio} = \frac{\text{Customer Group 1CP Metered Demand + Demand Losses}}{\text{Firm Transmission Peak Demand}}$$

In order to determine the transmission system peak demands, the company must be able to monitor the utility's demands on its production facilities and the power flows entering its system. To determine the customer group's actual demand at the time of the transmission system's peak demand, the utility must have either time-demand meters, or employ statistical techniques to determine the relationship between the individual customer's billing demand and its actual incurrence. See Table 5-2 for illustrative example of 1CP allocation methodology.

TABLE 5-2

EXAMPLE OF SINGLE SYSTEM PEAK DEMAND ALLOCATION

Customer group CP demand at system CP (Sep)	491
System CP(MW)	15050
1 CP customer group demand ratio	.03262

2. The Average Seasonal System Coincident Peak Method

Because of heating and air conditioning loads, a utility may experience peak demands of comparable magnitude during different seasons of the year. The peak demands during those seasons may be considerably higher than those for the remaining months of the year, and the actual peak month may rotate from year to year between the seasons. In addition, the high level of usages may be sustained longer in one season than the other.

The calculation of the average seasonal CP demand allocation requires data for the company's transmission peak demands for the allocation periods selected and the demands of the customer groups at the same hours and days for each of those periods. The problem of implementation is the same as for the 1CP demand allocation method, except that data for more than one period is needed.

The average seasonal CP demand allocation ratio is computed by dividing the sum of the customer group's demands at the peak periods by the sum of the utility's transmission demands during those same periods. The demand ratios are computed as follows:

$$\text{Seasonal CP Demand Ratio} = \frac{\text{Sum of Customer Seasonal CP Demands \& Demand Losses}}{\text{Sum of Seasonal Transmission System Peaks}}$$

Implementation of the average seasonal CP demand allocation method will involve the same type of data and the same difficulties, except that data for more than one allocation period are required. See Table 5-3 for sample application of seasonal CP allocation methodology.

TABLE 5-3

EXAMPLE OF AVERAGE SEASONAL SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP total for months of July, August and September*	1539
System CP total for the same month(MW)	43390
Customer group average seasonal demand ratio	.03547

* Selection of July-September period is based on criterion of using months with system CP demand of at least 90% of system annual CP demand. Actual selection may consider historical occurrence of CP demand in additional months.

3. The Average of the 12 Monthly System Coincident (12 CP) Peak Method

The 12 CP demand allocation method is based on the principle that a utility installs facilities to maintain a reasonably constant level of reliability throughout the year or that significant variations in monthly peak demands are not present. Under this method, no single peak demand or seasonal peak demands are of any significantly greater magnitude than any of the other monthly coincident peak demands. Thus, the relative importance of each month is considered.

To implement this method, data for the monthly coincident peak demands of each customer at each delivery point for the year must be available. For example, if the company's monthly system peak demand for August occurs on August 10th at 4 P.M., then data for each customers' demand at that specific point in time must be available. Additionally, similar data would be required for each day the company's system peak occurred in the other eleven months in the selected test year.

Customer responsibility under this allocation method is computed as follows:

$$\text{12CP Customer Group Demand Ratio} = \frac{\text{Cust Group 12CP Metered Demand + Demand Losses}}{\text{Transmission System 12CP Demand}}$$

Coincident peak demand data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The coincident peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-4 for sample application of this methodology.

TABLE 5-4

EXAMPLE OF 12 MONTHLY SYSTEM COINCIDENT PEAK ALLOCATION

Customer group CP demand total(MW)	4900
System CP demand total(MW)	142830
12 CP customer group demand ratio	.03431

4. The Single Non-Coincident Peak (NCP) Demand Allocation Method

The NCP method attempts to give recognition to the maximum demand placed upon a system during the year by all customers. This method is based on the theory that facilities are sized to meet these maximum demands. Therefore, the costs of the facilities are allocated in accordance with each customer's contribution to the sum of the maximum demands of all customers' imposed on the facilities.

Customer responsibility under this method is computed as follows:

$$\text{Customer Group NCP Demand Ratio} = \frac{\text{Cust Group NCP Metered Demand + Demand Losses}}{\text{Transmission System NCP Demand}}$$

Data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. Thus, large groups of retail customers will benefit from the diversity among their loads in the allocation process. See Table 5-5 for a sample application of the single NCP allocation methodology.

TABLE 5-5

EXAMPLE OF SINGLE NON-COINCIDENT PEAK DEMAND ALLOCATION

Customer group NCP demand (MW)	520
System NCP demand*	15842
Customer group NCP demand ratio	.03282

* Assuming a coincidence factor of .95 for the system, NCP for CP demand of 15050 MW would equal 15842 MW.

5. The Monthly Average NCP Demand Allocation Method

The monthly average NCP demand allocation method attempts to give recognition to the variation or diversity among monthly NCP demands placed on a system during the year by all customers. This in effect recognizes the fact that facilities are installed to provide reliable service throughout the year including periods of scheduled maintenance. Costs of the facilities are allocated in accordance with each customer's average monthly contribution to the sum of the average monthly maximum demands of all customers.

As with the NCP method, data for individual customers such as municipal or cooperative systems is usually readily available by delivery point. The maximum peak demands of individual or groups of retail customers are not available since many retail loads are not demand metered. See Table 5-6 for sample application of monthly average NCP allocation methodology.

TABLE 5-6

EXAMPLE OF MONTHLY AVERAGE NCP DEMAND ALLOCATION

Customer group NCP demand total(MW)	4778
System NCP demand total*	150347
Customer group monthly average NCP demand ratio	.03178

* Assuming a coincidence factor of .95 for the system, NCP for system CP monthly demands as shown in Table 5-1 would total 150347 MW.

6. Average and Excess Allocation Method

In contrast to the various peak demand allocation methods which assign costs based entirely on peak demand responsibility, under the average and excess demand allocation method (A&E) transmission costs are divided into two parts for allocation purposes on both demand and energy based on the system load factor (the ratio of the average load over a designated period to the peak demand occurring in that period). As such, the A&E method emphasizes or recognizes the extent of the use of capacity resulting in allocation of an increasing proportion of capacity costs to a customer group as its load factor increases. This theory implies that a utility's capacity serves a dual function -- while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs. Use of the A&E method for allocating transmission costs is typically employed for consistency when production costs are allocated on the same basis.

Because the A&E method does not recognize the coincident peak contribution of a customer group's load, the data necessary to perform the calculation is limited to the energy consumption and maximum (non-coincident) demand for a given period.

The first half of the formula, the "average" component representing the customer group's average energy consumption, allocates transmission costs on an energy use or average demand basis. The second half of the formula, the "excess" component is derived from the difference between the customer group's maximum non-coincident peak demand and the "average" demand component. The A&E method is expressed algebraically as follows:

$$D = L \times \frac{A}{B} + (1\text{-}L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor
A = customer group's energy requirements
B = total system energy requirements
C = customer group's "excess" demand responsibility
E = sum of all customer groups' "excess" demand responsibility

Implementation problems associated with the A&E method are inherent in the complexity of the computation. Additional complications may arise in an attempt to recognize that demand meter readings are not taken on a consistent basis, e.g., a large bulk power customer may reflect a greater degree of diversity as compared to a smaller low voltage distribution customer with little or no diversity. See Table 5-7 for sample application of average and excess allocation methodology.

TABLE 5-7

EXAMPLE OF AVERAGE AND EXCESS DEMAND ALLOCATION

$$D = L \times \frac{A}{B} + (1\text{-}L) \times \frac{C}{E}$$

Where: D = customer group's demand responsibility ratio
L = system's annual load factor = $\frac{\text{average load for year}}{\text{peak load for year}}$

$$= \frac{\dfrac{\text{70470 million KWH (Table 5-1)}}{\text{8784 hrs/yr}}}{\text{15,050,000 KW (Table 5-1)}} = 53.3\%$$

A = customer group's energy requirements = 2449 million KWH assuming monthly load factor of 70%
B = total system energy requirements = 70,470 million KWH
(1-L) = 46.5%
C = customer group's "excess" demand responsibility

$$= \text{520 MW (Table 5-1)} - \frac{\text{2449 million KWH}}{\text{8784 hrs in 1988}} = \text{241 MW}$$

E = 15842 MW (Table 5-1 CP demand for system at .95 coincidence factor) - $\frac{\text{70470 million KWH}}{\text{8784 hrs in 1988}}$

= 7819 MW

Therefore: $D = (53.3\%)\ \frac{2449 \times 10^6}{70,470 \times 10^6} + (46.7\%)\ \frac{\text{241 MW}}{\text{7819 MW}} = .032917$

7. Combination of Other Methods

The preceding discussions have addressed situations involving allocation of various firm transmission investments to firm power loads. Depending on the factual situation present on a utility's system, it may be appropriate to employ a combination of methods to properly allocate cost responsibility to customers. Thus, an NCP allocation is sometimes used to allocate subtransmission costs, while a peak responsibility method based on coincident demands is used for the higher order transmission facilities. In addition, where certain customers may exhibit load patterns that are not adequately represented in their coincident load data, other factors not normally employed in a peak responsibility method may need to be introduced to assure proper cost allocation.

With regard to non-firm transmission services, while it may or may not be true that such services should not be held responsible for any demand costs, it should also be recognized that non-firm services require very close analysis of service contract provisions to determine utility obligations in order to establish the correct basis for allocation.

B. <u>Direct Assignment</u>

The costs of specific transmission facilities, such as long radial transmission lines and substations, may be directly assigned to particular customers. Direct assignments of such costs implies that the facilities can be considered entirely apart from the integrated system. In fact, the case for the independence of the facilities must be unequivocal since the customer must be willing to bear all the costs of service that, due to the unintegrated character of the facilities, may be just as high for service that is less reliable than service on the integrated system.

Costs assigned directly to customers are often collected via a special facilities charge. The charge can reflect: (1) the installed costs of the facilities; or (2) the average system cost of such facilities.

The plant costs that are directly assigned to a customer group must be excluded from the utility's total transmission plant costs for allocation. Alternatively, the revenue can be treated for costing as a revenue credit.

III. WHEELING

Wheeling is a transfer of power over transmission facilities owned by a utility that does not produce or sell the transferred power. The transfer may either be on a simultaneous or non-simultaneous basis. On either basis, the actual source of the power delivered to the purchasing system is not necessarily from the contracted for power source. Instead, power from other sources may flow over the integrated transmission system to satisfy the loads of the owner who has contracted for the specific source of power that is to be wheeled. Power from the specific source will in turn be used to meet other loads on the integrated system. This process is often referred to as service by displacement. When the power to be wheeled is from a hydroelectric facility, the wheeling system will often assume scheduling responsibilities by entering into "energy banking" arrangements to maximize fuel cost economies on its own system. The energy banking arrangements are often used in the wheeling of preference power from a power marketing agency to small distribution systems dispersed within a larger system which performs the necessary wheeling services.

The simultaneous or non-simultaneous wheeling of power may be conducted on either a firm or non-firm basis. In either case, a continuous contract path is generally required between the power source and load of the system which is receiving wheeling service. Firm transmission services are intended to be available at all times during the contract and are essentially the unbundled transmission portion of requirements rates. The functionalization and allocation methods applied to requirements service are applicable to firm transmission service as well.

Non-firm wheeling service is usually available under arrangements which do not provide assurances of continuous availability to the customer. Intuitively, it would appear that the costs to be recovered for non-firm wheeling should be less than costs recovered for firm wheeling, provided that the costing basis for both is identical. However, since non-firm wheeling service is often associated with opportunity or interchange transactions among power systems -- where such transactions usually reflect incremental cost pricing or other non-embedded cost measurements -- the benefits of the interchange transactions may also be considered in the development of non-firm wheeling rates. Such consideration may be expressed in terms of the costs of foregone opportunities to the utility providing non-firm wheeling service. Thus, the methods of allocation used in costing firm transmission service may or may not represent a cost ceiling for non-firm transmission service rates.

The advance in computer technology is providing additional capability for allocating costs to more accurately determine revenue from providing transmission service. One of the new methods for allocating and pricing transmission service is based on the positive difference, MW-mile methodology. The development and application of the positive difference, MW-mile method for each party is a multi-step process. The first step is to compute the MW-mile rating of the wheeling utility's transmission system by multiplying the length of each transmission line by a percentage of the thermal rating of the line. The products are summed to provide the aggregate MW-mile and are determined at least annually. The aggregate MW-miles are summed and divided into the functionalized transmission cost of service of the wheeling utility to yield a dollar per MW-mile billing charge. The next step is to determine the wheeling utility's MW-mile billing units. Billing units are determined by the use of computer models. The utility arranges for two simulations of power flows on its system, one simulation with wheeling for the wheeling recipient and one without. The simulations are compared to determine the effects on the system of the wheeling utility's wheeling. Negative changes (i.e., line unloadings) are sometimes ignored. Each positive MW change on a line is multiplied by the line length and the products are summed to yield the wheeling utility's positive MW-mile billing units. The billing units are multiplied by the utility's MW-mile charge to develop the bill.

Schedule NLP-SR1

CHAPTER 6

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION PLANT

Distribution plant equipment reduces high-voltage energy from the transmission system to lower voltages, delivers it to the customer and monitors the amounts of energy used by the customer.

Distribution facilities provide service at two voltage levels: primary and secondary. Primary voltages exist between the substation power transformer and smaller line transformers at the customer's points of service. These voltages vary from system to system and usually range between 480 volts to 35 KV. In the last few years, advances in equipment and cable technology have permitted the use of higher primary distribution voltages. Primary voltages are reduced to more usable secondary voltages by smaller line transformers installed at customer locations along the primary distribution circuit. However, some large industrial customers may choose to install their own line transformers and take service at primary voltages because of their large electrical requirements.

In some cases, the utility may choose to install a transformer for the exclusive use of a single commercial or industrial customer. On the other hand, in service areas with high customer density, such as housing tracts, a line transformer will be installed to serve many customers. In this case, secondary voltage lines run from pole-to-pole or from handhole-to-handhole, and each customer is served by a drop tapped off the secondary line leading directly to the customer's premise.

I. COST ACCOUNTING FOR DISTRIBUTION PLANT AND EXPENSES

The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts requires separate accounts for distribution investment and expenses. Distribution plant accounts are summarized and classified in Table 6-1. Distribution expense accounts are summarized and classified in Table 6-2. Some utilities may choose to establish subaccounts for more detailed cost reporting.

TABLE 6-1

CLASSIFICATION OF DISTRIBUTION PLANT[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant [2]		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems [1]	-	-

[1]Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

TABLE 6-2

CLASSIFICATION OF DISTRIBUTION EXPENSES[1]

FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Operation [2]		
580	Operation Supervision & Engineering	X	X
581	Load Dispatching	X	-
582	Station Expenses	X	-
583	Overhead Line Expenses	X	X
584	Underground Line Expenses	X	X
585	Street Lighting & Signal System Expenses [1]	-	-
586	Meter Expenses	-	X
587	Customer Installation Expenses	-	X
588	Miscellaneous Distribution Expenses	X	X
589	Rents	X	X
	Maintenance [2]		
590	Maintenance Supervision & Engineering	X	X
591	Maintenance of Structures	X	X
592	Maintenance of Station Equipment	X	-
593	Maintenance of Overhead Lines	X	X
594	Maintenance of Underground Lines	X	X
595	Maintenance of Line Transformers	X	X
596	Maint. of Street Lighting & Signal Systems [1]	-	-
597	Maintenance of Meters	-	X
598	Maint. of Miscellaneous Distribution Plants	X	X

[1]Direct assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

[2]The amounts between classifications may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.

Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses. This will ensure that costs are assigned to the correct functional groups for classification and allocation. As indicated in Chapter 4, all costs of service can be identified as energy-related, demand-related, or customer-related. Because there is no energy component of distribution-related costs, we need consider only the demand and customer components.

To recognize voltage level and use of facilities in the functionalization of distribution costs, distribution line costs must be separated into overhead and underground, and primary and secondary voltage classifications. A typical functionalization and classification of distribution plant would appear as follows:

Substations:	Demand
Distribution:	Overhead Primary
	Demand
	Customer
	Overhead Secondary
	Demand
	Customer
	Underground Primary
	Demand
	Customer
	Underground Secondary
	Demand
	Customer
	Line Transformers
	Demand
	Customer
Services:	Overhead
	Demand
	Customer
	Underground
	Demand
	Customer
Meters:	Customer
Street Lighting:	Customer
Customer Accounting:	Customer
Sales:	Customer

From this breakdown it can be seen that each distribution account must be analyzed before it can be assigned to the appropriate functional category. Also, these accounts must be classified as demand-related, customer-related, or both. Some utilities assign distribution to customer-related expenses. Variations in the demands of various customer groups are used to develop the weighting factors for allocating costs to the appropriate group.

II. DEMAND AND CUSTOMER CLASSIFICATIONS 0F DISTRIBUTION PLANT ACCOUNTS

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Classifying distribution plant as a demand cost assigns investment of that plant to a customer or group of customers based upon its contribution to some total peak load. The reason is that costs are incurred to serve area load, rather than a specific number of customers.

Distribution substations costs (which include Accounts 360 -Land and Land Rights, 361 - Structures and Improvements, and 362 -Station Equipment), are normally classified as demand-related. This classification is adopted because substations are normally built to serve a particular load and their size is not affected by the number of customers to be served.

Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services, and meters are directly related to the number of customers on the utility's system. As shown in Table 6-1, each primary plant account can be separately classified into a demand and customer component. Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.

A. The Minimum-Size Method

Classifying distribution plant with the minimum-size method assumes that a minimum size distribution system can be built to serve the minimum loading requirements of the customer. The minimum-size method involves determining the minimum size pole, conductor, cable, transformer, and service that is currently installed by the utility. Normally, the average book cost for each piece of equipment determines the price of all installed units. Once determined for each primary plant account, the minimum size distribution system is classified as customer-related costs. The demand-related costs for each account are the difference between the total investment in the account and customer-related costs. Comparative studies between the minimum-size and other methods show that it generally produces a larger customer component than the zero-intercept method (to be discussed). The following describes the methodologies for determining the minimum size for distribution plant Accounts 364, 365, 366, 367, 368, and 369.

1. **Account 364 - Poles, Towers, and Fixtures**

   - Determine the average installed book cost of the minimum height pole currently being installed.

   - Multiply the average book cost by the number of poles to find the customer component. Balance of plant account is the demand component.

2. **Account 365 - Overhead Conductors and Devices**

   - Determine minimum size conductor currently being installed.

   - Multiply average installed book cost per mile of minimum size conductor by the number of circuit miles to determine the customer component. Balance of plant account is demand component. (Note: two conductors in minimum system.)

3. **Accounts 366 and 367 - Underground Conduits, Conductors, and Devices**

   - Determine minimum size cable currently being installed.

   - Multiply average installed book cost per mile of minimum size cable by the circuit miles to determine the customer component. Balance of plant Account 367 is demand component. (Note: one cable with ground sheath is minimum system.) Account 366 conduit is assigned, basedon ratio of cable account.

   - Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component. Balance of plant account is demand component..

4. **Account 368 - Line Transformers**

   - Determine minimum size transformer currently being installed.

- Multiply average installed book cost of minimum size transformer by number of transformers in plant account to determine the customer component.

5. Account 369 - Services

- Determine minimum size and average length of services currently being installed.
- Estimate cost of minimum size service and multiply by number of services to get customer component.
- If overhead and underground services are booked separately, they should be handled separately. Most companies do not book service by size. This requires an engineering estimate of the cost of the minimum size, average length service. The resultant estimate is usually higher than the average book cost. In addition, the estimate should be adjusted for the average age of service, using a trend factor.

B. The Minimum-Intercept Method

The minimum-intercept method seeks to identify that portion of plant related to a hypothetical no-load or zero-intercept situation. This requires considerably more data and calculation than the minimum-size method. In most instances, it is more accurate, although the differences may be relatively small. The technique is to relate installed cost to current carrying capacity or demand rating, create a curve for various sizes of the equipment involved, using regression techniques, and extend the curve to a no-load intercept. The cost related to the zero-intercept is the customer component. The following describes the methodologies for determining the minimum intercept for distribution-plant Accounts 364, 365, 366, 367, and 368.

1. Account 364 - Poles, Towers, and Fixtures

- Determine the number, investment, and average installed book cost of distribution poles by height and class of pole. (Exclude stubs for guying.)
- Determine minimum intercept of pole cost by creating a regression equation, relating classes and heights of poles, and using the Class 7 cost intercept for each pole of equal height weighted by the number of poles in each height category.
- Multiply minimum intercept cost by total number of distribution poles to get customer component.

- Balance of pole investment is assigned to demand component.

- Total account dollars are assigned based on ratio of pole investment. (Transformer platforms in Account 364 are all demand-related. They should be removed before determining the account ratio of customer- and demand-related costs, and then they should be added to the demand portion of Account 364.)

2. Account 365 - Overhead Conductors and Devices

- If accounts are divided between primary and secondary voltages, develop a customer component separately for each. The total investment is assigned to primary and secondary; then the customer component is developed for each. Since conductors generally are of many types and sizes, select those sizes and types which represent the bulk of the investment in this account, if appropriate.

- When developing the customer component, consider only the investment in conductors, and not such devices as circuit breakers, insulators, switches, etc. The investment in these devices will be assigned later between the customer and demand component, based on the conductor assignment.

  - Determine the feet, investment, and average installed book cost per foot for distribution conductors by size and type.

  - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor weighted by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

  - Multiply minimum intercept cost by the total number of circuit feet times 2. (Note that circuit feet, not conductor feet, are used to get customer component.)

  - Balance of conductor investment is assigned to demand.

  - Total primary or secondary dollars in the account, including devices, are assigned to customer and demand components based on conductor investment ratio.

3. Accounts 366 and 367 - Underground Conduits, Conductors, and Devices

- The customer demand component ratio is developed for conductors and applied to conduits. Underground conductors are generally booked by type and size of conductor for both one-conductor (I/c) cable and three-conductor (3/c) cables. If conductors are booked by voltage, as between primary and secondary, a customer component is developed for each. If network and URD investments are segregated, a customer component must be developed for each.

- The conductor sizes and types for the customer component derivation are restricted to I/c cable. Since there are generally many types and sizes of I/c cable, select those sizes and types which represent the bulk of the investment, when appropriate.

  - Determine the feet, investment, and average installed book cost per foot for I/c cables by size and type of cable.

  - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable weighted by feet of investment in each category.

  - Multiply minimum intercept cost by the total number of circuit feet (I/c cable with sheath is considered a circuit) to get customer component.

  - Balance of cable investment is assigned to demand.

  - Total dollars in Accounts 366 and 367 are assigned to customer and demand components based on conductor investment ratio.

4. Account 368 - Line Transformers

- The line transformer account covers all sizes and voltages for single- and three-phase transformers. Only single-phase sizes up to and including 50 KVA should be used in developing the customer components. Where more than one primary distribution voltage is used, it may be appropriate to use the transformer price from one or two predominant, selected voltages.

  - Determine the number, investment, and average installed book cost per transformer by size and type (voltage).

  - Determine zero intercept of transformer cost using cost per transformer by type, weighted by number for each category.

  - Multiply zero intercept cost by total number of line transformers to get customer component.

  - Balance of transformer investment is assigned to demand component.

  - Total dollars in the account are assigned to customer and demand components based on transformer investment ratio from customer and demand components.

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Similarly, when designing primary and secondary distribution feeders, the distribution engineer ensures that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary- and secondary-distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class noncoincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities. The customer-class load characteristic used to allocate the demand component of distribution plant (whether customer class NCPs or the summation of individual customer maximum demands) depends on the load diversity that is present at the equipment to be allocated. The load diversity at distribution substations and primary feeders is usually high. For this reason, customer-class peaks are normally used for the allocation of these facilities. The facilities nearer the customer, such as secondary feeders and line transformers, have much lower load diversity. They are normally allocated according to the individual customer's maximum demands. Although these are the methods normally used for the allocation of distribution demand costs, some exceptions exist.

The load diversity differences for some utilities at the transmission and distribution substation levels may not be large. Consequently, some large distribution substations may be allocated using the same method as the transmission system. Before the cost analyst selects a method to allocate the different levels of distribution facilities, he must know the design and operational characteristics of the distribution system, as well as the demand losses at each level of the distribution system.

As previously indicated, the distribution system consists of several levels. The first level starts at the distribution substation, and the last level ends at the customer's meters. Power losses occur at each level and should be included in the demand allocators. Power losses are incorporated into the demand allocators by showing different demand loss factors at each predominant voltage level. The demand loss factor used to develop the primary-distribution demand allocator will be slightly larger than the demand loss factor used to develop the secondary demand allocator. When developing the distribution demand allocator, be aware that some customers take service at different voltage levels.

Cost analysts developing the allocator for distribution of substations or primary demand facilities must ensure that only the loads of those customers who benefit from these facilities are included in the allocator. For example, the loads of customers who take service at transmission level should not be reflected in the distribution substation or primary demand allocator. Similarly, when analysts develop the allocator for secondary demand facilities, the loads for customers served by the primary distribution system should not be included.

Utilities can gather load data to develop demand allocators, either through their load research program or their transformer load management program. In most cases, the load research program gathers data from meters on the customers' premises. A more complex procedure is to use the transformer load management program.

This procedure involves simulating load profiles for the various classes of equipment on the distribution system. This provides information on the nature of the load diversity between the customer and the substation, and its effect on equipment cost. Determining demand allocators through simulation provides a first-order load approximation, which represents the peak load for each type of distribution equipment.

The concept of peak load or "equipment peak" for each piece of distribution equipment can be understood by considering line transformers. If a given transformer's loading for each hour of a month can be calculated, a transformer load curve can be developed. By knowing the types of customers connected to each load management transformer, a simulated transformer load profile curve can be developed for the system. This can provide each customer's class demand at the time of the transformer's peak load. Similarly, an equipment peak can be defined for equipment at each level of the distribution system. Although the equipment peak obtained by this method may not be ideal, it will closely approximate the actual peak. Thus, this method should reflect the different load diversities among customers at each level of the distribution system. An illustration of the simulation procedure is provided in Appendix 6-A.

B. Allocation of Customer-Related Costs

When the demand-customer classification has been completed, most of the assumptions will have been made that affect the results of the completed cost of service study.

The allocation of the customer-related portion of the various plant accounts is based on the number of customers by classes of service, with appropriate weightings and adjustments. Weighting factors reflect differences in characteristics of customers within a given class, or between classes. Within a class, for instance, we may want to give more weighting of a certain plant account to rural customers, as compared to urban customers. The metering account is a clear example of an account requiring weighting for differences between classes. A metering arrangement for a single industrial customer may be 20 to 80 times as costly as the metering for one residential customer.

While customer allocation factors should be weighted to offset differences among various types of customers, highly refined weighting factors or detailed and time consuming studies may not seem worthwhile. Such factors applied in this final step of the cost study may affect the final results much less than such basic assumptions as the demand-allocation method or the technique for determining demand-customer classifications.

Expense allocations generally are based on the comparable plant allocator of the various classes. For instance, maintenance of overhead lines is generally assumed to be directly related to plant in overhead conductors and devices. Exceptions to this rule will occur in some accounts. Meter expenses, for example, are often a function of maintenance and testing schedules related more to revenue per customer than to the cost of the meters themselves.

APPENDIX 6-A

DERIVATION OF DEMAND ALLOCATOR THROUGH SIMULATION

The derivation of the demand allocator through simulation requires extensive data on the locations of various types of customers on the distribution system. This data may be available through the utility's transformer load management (TLM) system.

A TLM system may be used by a utility to provide data to minimize the loss of transformers from overload and to provide a data base for local area forecasts for engineering design. Such a data base can provide the location and size of line transformers, and identify the primary feeder leaving the substation that supplies each transformer. It can also provide the identity of the customer connected to each transformer and the usage levels of those customers. Additional sampling may be necessary to determine which transformers have secondary lines between the transformers and the customer service drops. In a simulation, the TLM data can be combined with the utility's load research data to obtain peak loading at points in the system not normally metered, as well as a matching set of the sales peak measurements normally made.

To calculate equipment peaks on an ongoing basis, a sample of transformers would have to be selected for load research metering, which could be projected to the total population of transformers. However, this may not be feasible because the cost of such a project could far outweigh the benefit derived. On the other hand, sales peaks calculated from existing load research sampling are available. This load research data could be used with the TLM data to simulate equipment peaks and their corresponding sales peaks. By comparing the peaks, we can select an appropriate allocator for each engineering category. The purpose of the simulation is not to calculate the allocators themselves, but to investigate the relationship between the equipment peaks and the sales peaks. This will allow us to choose appropriate sales peaks for allocating each engineering category.

From the TLM data, we can identify the specific transformer, three-phase circuit (feeder), and distribution substation serving each customer. Given the customer load profiles for each hour of a particular month, we can then add up the hourly load for each transformer, circuit, or substation, find its peak, and add totals by rate schedule to the equipment peaks. The key element of the simulation is the load profile of each customer.

How to generate a customer load profile and use it to simulate equipment peaks is shown below. Line transformers are used for illustration. After sorting the TLM data by transformer number, follow these steps:

Step 1 - Read a customer record from the TLM data file.

Step 2 - Test the transformer number to determine if a new transformer has been found. If not, proceed to Step 3; otherwise, go to Step 7.

Step 3 - From the TLM data, use the rate schedule and the KWH/day to identify a set of load profiles from the proper strata with the matching rate schedule.

Step 4 - Generate and use a pseudo-random number to select one of the load profiles within the identified set.

Step 5 - Combine the hourly loads for the selected load profile to yield the same total energy consumed in the TLM data. This is done by taking the TLM KWH/day divided by the KWH/day for the selected load profile and multiplying the result by the load for each hour of the selected load profile.

Step 6 - Add the customer's simulated hourly loads to the totals by rate schedule for the customer's transformer, and to the totals for the various sales peaks being generated. Now return to Step 1.

Step 7 - If you detect the end of data for a transformer, the transformer totals will contain simulated hourly loads for each hour of the month for that transformer. Search these loads to find the transformer's peak load hour. Add the loads for each rate schedule at the time of this peak to the equipment peak totals by rate schedule. Then clear the transformer totals and proceed to the next transformer in Step 3.

Determine the simulation of equipment peaks for substations and primary and secondary conductors in the same manner. The estimated equipment peaks for each month for each distribution component can then be compared to various class peaks (monthly coincident peaks, noncoincident peaks, etc.) that are available from load research data. The class peak factors that best match the equipment peaks should then be used to allocate each distribution component.

CHAPTER 7

CLASSIFICATION AND ALLOCATION OF CUSTOMER-RELATED COSTS

Customer-related costs (Accounts 901-917) include the costs of billing and collection, providing service information, and advertising and promotion of utility services. By their nature, it is difficult to determine the "cause" of these costs by any particular function of the utility's operation or by particular classes of their customers. An exception would be Account 904, Uncollectible Accounts. Many utilities monitor the uncollectible account levels by tariff schedule. Therefore, it may be appropriate to directly assign uncollectible accounts expense to specific customer classes.

I. FUNCTIONALIZATION

The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.

A less common approach is called the plant/labor method that functionalizes customer accounts, customer service, and sales expenses according to the previously determined functionalization of utility plant and labor costs. The amount of payroll costs included in generation-, transmission-, and distribution-related operation and maintenance expenses determine the labor component of this functionalization. Since the majority of a utility's labor costs tend to be in distribution, the plant/labor method will tend to emphasize the distribution functionalization of customer accounts, customer service, and sales expenses.

II. CLASSIFICATION AND ALLOCATION

When these expenses are functionalized by the plant/labor method, they will follow the previously determined classification and allocation of generation, transmission, and distribution facilities.

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Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.

A. Customer Account Expenses (Accounts 901 - 905)

These accounts are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts, which may be directly assigned to customer classes. Some analysts prefer to regard uncollectible accounts as a general cost of performing business by the utility, and would classify and allocate these costs based upon an overall allocation scheme, such as class revenue responsibility.

B. Customer Service and Informational Expenses (Accounts 906 - 910)

These accounts include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer-related. Emphasis is placed upon the costs of responding to customer inquiries and preparing billing inserts.

Conservation and load management costs should be separately analyzed. These programs should be classified according to program goals. For example, a load management program for cycling air conditioning load is designed to save generation during peak hours. This program could be classified as generation-related and allocated on the basis of peak demand. The goal of other conservation programs may be to save electricity on an annual basis. These costs could be classified as generation-related and allocated on the basis of energy-usage allocation. However, if conservation costs are received through cost recovery similar to a fuel-cost recovery clause, allocating the costs between demand and energy may be too cumbersome. In such cases, the costs could be received through an energy clause. A demand-saving load management program actually saves marginal fuel costs, and therefore energy.

C. Sales Expenses (Accounts 911 - 917)

These accounts include the costs of exhibitions, displays, and advertising designed to promote utility service. These costs could be classified as customer-related, since the goal of demonstrations and advertising is to influence customers. Allocation of these costs, however, should be based upon some general allocation scheme, not numbers of customers. Although these costs are incurred to influence the usage decisions of customers, they cannot properly be said to vary with the number of customers. These costs should be either directly assigned to each customer class when data are available, or allocated based upon the overall revenue responsibility of each class.

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CHAPTER 8

CLASSIFICATION AND ALLOCATION OF COMMON AND GENERAL PLANT INVESTMENTS AND ADMINISTRATIVE AND GENERAL EXPENSES

This chapter describes how general plant investments and administrative and general expenses are treated in a cost of service study. These accounts are listed in the general plant Accounts 389 through 399, and in the administrative and general Accounts 920 through 935.

I. GENERAL PLANT

General plant expenses include Accounts 389 through 399 and are that portion of the plant that are not included in production, transmission, or distribution accounts, but which are, nonetheless, necessary to provide electric service.

One approach to the functionalization, classification, and allocation of general plant is to assign the total dollar investment on the same basis as the sum of the allocated investments in production, transmission and distribution plant. This type of allocation rests on the theory that general plant supports the other plant functions.

Another method is more detailed. Each item of general plant or groups of general and common plant items is functionalized, classified, and allocated. For example, the investment in a general office building can be functionalized by estimating the space used in the building by the primary functions (production, transmission, distribution, customer accounting and customer information). This approach is more time-consuming and presents additional allocation questions such as how to allocate the common facilities such as the general corporate computer space, the Shareholder Relation Office space, etc.

Another suggested basis is the use of operating labor ratios. In performing the cost of service study, operation and maintenance expenses for production, transmission, distribution, customer accounting and customer information have already been functionalized, classified, and allocated. Consequently, the amount of labor, wages, and salaries assigned to each function is known, and a set of labor expense ratios is thus available for use in allocating accounts such as transportation equipment, communication equipment, investments or general office space.

II. ADMINISTRATIVE AND GENERAL EXPENSES

Administrative and general expenses include Accounts 920 through 935 and are allocated with an approach similar to that utilized for general plant. One methodology, the two-factor approach, allocates the administrative and general expense accounts on the basis of the sum of the other operating and maintenance expenses (excluding fuel and purchased power).

A more detailed methodology classifies the administrative and general expense accounts into three major components: those which are labor related; those which are plant related; and those which require special analysis for assignment or the application of the beneficiality criteria for assignment.

The following tabulation presents an example of the cost functionalization and allocation of administrative and general expenses using the three-factor approach and the two-factor approach.

Account Operation		Three-Factor Allocation Basis	Two-Factor Allocation Basis
920	A & G Salaries	Labor - Salary and Wages	Labor - Salary and Wages
921	Office Supplies	Labor - Salary and Wage	Labor - Salary and Wages
922	Administration Expenses Transferred-Credit	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
923	Outside Services Employed	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
924	Property Insurance	Plant - Total Plant [1]	Plant - Total Plant
925	Injuries and Damages	Labor - Salary and Wages[2]	Labor - Salary and Wages
926	Pensions and Benefits	Labor - Salary and Wages	Labor - Salary and Wages
927	Franchise Requirements	Revenues or specific assignment	Revenues or specific assignment

[1]A utility that self-insures certain parts of its utility plant may require the adjustment of this allocator to only include that portion for which the expense is incurred.

[2]A detailed analysis of this account may be necessary to learn the nature and amount of the expenses being booked to it. Certain charges may be more closely related to certain plant accounts than to labor wages.

Account Operation		Three Factor Allocation Basis	Labor-Ratio Allocation Basis
928	Regulatory Commission Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
928	Duplicate Charge-Cr.	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.1	General Advertising Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
930.2	Miscellaneous General Expenses	Other - Subtotal of Operating Expenses Less Fuel and Purchased Power	Labor - Salary and Wages
931	Rents	Plant - Total Plant[3]	Plant - Total Plant
Maintenance		**Three Factor Allocation Basis**	**Labor-Ratio Allocation Basis**
935	General Plant	Plant - Gross Plant	Labor - Salary and Wages

[3]A detailed analysis of rental payments may be necessary to determine the correct allocation bias. If the expenses booked are predominantly for the rental of office space, the use of labor, wage and salary allocators would be more appropriate.

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SECTION III

MARGINAL COST STUDIES

SECTION III reviews marginal cost of service studies. As noted in Chapter 2, in contrast to embedded studies where the issues primarily involve the allocation of costs taken from the company's books, the practical and theoretical debates in marginal cost studies center around the development of the costs themselves.

Chapter 9 discusses marginal production costs, including the costing methodologies and allocation to time periods and customer classes of the energy and capacity components.

Chapter 10 discusses the costing methodologies and allocation issues for marginal transmission, distribution and customer charges.

Use of marginal cost methodologies in ratemaking is based on arguments of economic efficiency. Pricing a utility's output at marginal cost, however, will only by rare coincidence recover the allowed revenue requirement.

Chapter 11 discusses the major approaches used to reconcile the marginal cost results to the revenue requirement.

CHAPTER 9

MARGINAL PRODUCTION COST

Marginal production cost is the change in the cost of producing electricity in response to a small change in customer usage. Marginal production cost includes an energy production component, referred to as marginal energy cost, and a generation-related reliability component, referred to as marginal capacity cost. Marginal capacity cost is one reliability-related component of the marginal costs associated with a change in customer usage. The other components, marginal transmission cost and marginal distribution cost, are discussed in Chapter 10. Together, these three reliability-related marginal costs are sometimes referred to as marginal demand cost. These marginal costs are used to calculate marginal cost revenues, which are used in cost allocation, as discussed in Chapter 11.

Marginal costs are commonly time-differentiated to reflect variations in the cost of serving additional customer usage during the course of a day or across seasons. Marginal production costs tend to be highest during peak load periods when generating units with the highest operating costs are on line and when the potential for generation-related load curtailments or interruptions is greatest. A costing period is a unit of time in which costs are separately identified and causally attributed to different classes of customers. Costing periods are often disaggregated hourly in marginal cost studies, particularly for determining marginal capacity costs which are usually strongly related to hourly system load levels. A rating period is a unit of time over which costs are averaged for the purpose of setting rates or prices. Rating periods are selected to group together periods with similar costs, while giving consideration to the administrative cost of time-differentiated rate structures. Where time-differentiated rates are employed, typical rate structures might be an on-peak and off-peak period, differentiated between a summer and winter season.

Two separate measures of marginal cost, long-run marginal cost and short-run marginal cost, can be employed in cost allocation studies. In economic terms, long-run marginal cost refers to the cost of serving a change in customer usage when all factors of production (i.e., capital facilities, fuel stock, personnel, etc.) can be varied to achieve least-cost production. Short-run marginal cost refers to the cost of serving a change in customer usage when some factors of production, usually capital facilities, are fixed. For example, if load rises unexpectedly, short-run marginal cost could be high as the utility seeks to meet this load with existing resources (i.e., the short-run perspective). Similarly, if a utility has surplus capacity, short-run marginal cost could be low, since capacity additions would provide relatively few benefits to the utility. When a utility system is optimally designed (utility facilities meet customer needs at lowest total cost), long-run and short-run marginal costs are equal.

A common source of confusion in marginal cost studies arises in considering the economic time frame of investment decisions. There is an incorrect tendency to equate long-run marginal cost with the economic life of new facilities, suggesting that long-run marginal cost has a multi-year character. In actuality, both short-run and long-run marginal costs are measured at a single point in time, such as a rate proceeding test year.[1]

There is considerable difference of opinion as to whether short-run or long-run marginal cost is appropriate for use in cost allocation. In competitive markets, prices tend to reflect short-run marginal costs, suggesting that this may be the appropriate basis for cost allocation. However, long-run marginal costs tend to be more stable and may send better price signals to customers making capital investment decisions than do short-run marginal costs.[2]

I. MARGINAL ENERGY COSTS

Marginal energy cost refers to the change in costs of operating and maintaining the utility generating system in response to a change in customer usage. Marginal energy costs consist of incremental fuel or purchased power costs[3] and variable operation and maintenance expenses incurred to meet the change in customer usage. Fixed fuel costs associated with committing generating units to operation are also a component of marginal energy costs when a change in customer usage results in a change in unit commitment.[4]

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[1]In contrast, analysis of investment decisions properly requires a projection of short-run marginal cost over the economic life of the investment. Long-run marginal cost is sometimes used to estimate projected short-run marginal cost (ignoring factors such as productivity change which may cause long-run marginal cost to vary over time), which perhaps contributes to the mistaken views regarding the economic time frame of long-run marginal cost.

[2]See, for example, the discussion in A. E. Kahn, The Economics of Regulation: Principles and Institutions, 1970, particularly Volume 1, Chapter 3.

[3]Incremental fuel costs are sometimes referred to as system lambda costs.

[4]These fixed fuel costs are commonly associated with conventional fossil fuel units which are used to follow load variations. These units often require a lengthy start-up period where a fuel input is required to bring the units to operational status. The cost of this fuel input is referred to as start-up fuel expenses. Also, at low levels of generation output, average fuel costs exceed incremental fuel costs because there are certain "overhead" costs, such as frictional losses and thermal losses, which occur inrrespective of the level of the level of generator output. These costs are sometimes referred to as "no-load" fuel costs since they are unrelated to the amount of load placed on the generating unit.

A. Costing Methodologies

The predominant methodology for developing marginal energy costs is the use of a production costing model to simulate the effect of a change in customer usage on the utility system production costs. Typically, a utility will operate its lower production cost resources whenever possible, relying on units with the highest energy production costs only when production potential from lower-cost resources has been fully utilized. Thus, the energy production costs for the most expensive generating units on line are indicative of marginal energy costs. However, utility generating systems are frequently complex, with physical operating constraints, contractual obligations, and spinning reserve requirements, sometimes making it difficult in practice to easily determine how costs change in response to a change in usage. A detailed simulation model reflecting the important characteristics of a utility's generating system can be a very useful tool for making a reasonable determination of marginal energy costs.

An alternative to using a production costing model is to develop an estimate of marginal energy costs for an historical period and apply this historical result to a test year forecast period. For historical studies, marginal energy costs can be expressed in terms of an equivalent incremental energy rate (in BTU/KWH), which reflects aggregate system fuel use efficiency. Expressing marginal energy costs in these units nets out the effect of changing fuel prices on marginal energy costs [5]. The use of historical studies should be approached with caution, however, when there is a significant change in system configuration (e.g., addition of a large baseload generating station), or where there are sizable variations in hydro availability. In these instances, system efficiency may change sufficiently to render historical studies unreliable as the basis for a test year forecast.

[5] The incremental energy rate, or IER, is conceptually similar to an incremental heat rate, but measures aggregate <u>system</u> efficiency rather than unit-specific efficiency. The IER is calculated by dividing marginal energy costs by the price of the fuel predominantely used in meeting a change in usage. When the price of this predominant fuel changes, marginal energy cost can be approximated as the fuel price (¢/BTU) times the IER (BTU/KWH).

1. Production Cost Modeling

There are numerous computer models suitable for performing a simulated utility dispatch and determining marginal energy costs that are commercially available[6]. These production cost models require a considerable degree of technical sophistication on the part of the user. In general, results are highly sensitive both to the structural description of the utility system contained in the input data and the actual values of the input data. Verification or "benchmarking" of model performance in measuring marginal energy costs is an important step which should be undertaken prior to relying on a model in regulatory proceedings.

Typically, production cost models produce an output report showing marginal energy costs by hour and month. These reported costs represent the incremental cost of changing the level of output from the most expensive generating unit on line to meet a small change in customer usage. However, these costs do not include the effect of temporal interdependencies which should be accounted for in marginal energy costs. For example, if a unit with a lengthy start-up cycle is started on Sunday evening to be available for a Monday afternoon peak, the costs of starting up the unit are properly ascribed to this Monday peak period.

The effect of such temporal interdependencies can be measured with a production cost model using the incremental-decremental load method. The production cost model is first run to establish a base case total production cost. Then, for each costing period, two additional model runs are performed, adjusting the input load profile upward and downward by a chosen amount. The change in total production cost per KWH change in load is calculated for both the incremental and decremental cases, and the results averaged to give marginal energy costs by costing period.

The results of a production cost model simulation for the utility case study are shown in Table 9-1. The analysis uses an incremental/decremental load method to account for fixed fuel expenses associated with the additional unit commitment needed to meet a change in load during on-peak and mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment. and

[6]Comparing and contrasting the efficacy of different production costing models is a complex undertaking that will not be attempted in this manual. The "state-of-the-art" in production cost modeling is envolving rapidly, with existing models increasing in sophistication and new models being developed.

mid-peak periods. Off-peak marginal energy costs are derived directly from the production cost model's reported marginal energy costs, since changes in off-peak usage are not anticipated to affect unit commitment.

TABLE 9-1

MARGINAL ENERGY COST CALCULATION USING AN INCREMENTAL/DECREMENTAL LOAD METHODOLOGY

(Based on a Gas Price of $2.70/MMBTU)

	500 MW Decrement	500 MW Increment	Combined
Summer On-Peak			
Change in Production Cost ($)	-9,120	+9,209	18,329
Change in KWH Production (GWH)	-261	+261	522
Marginal Cost (¢/KWH)			3.5
In BTU/KWH			12,993
Summer Mid -Peak			
Change in Production Cost ($)	-9,613	+9,631	19,244
Change in KWH Production (GWH)	-393	+393	786
Marginal Cost (¢/KWH)			2.4
In BTU/KWH			9,089
Summer Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.2
In BTU/KWH			8,129
Winter On-Peak			
Change in Production Cost ($)	-9,930	+11,479	21,409
Change in KWH Production (GWH)	-348	+348	696
Marginal Cost (¢/KWH)			3.1
In BTU/KWH			11,393
Winter Mid-Peak			
Change in Production Cost ($)	-19,843	+19,411	39,254
Change in KWH Production (GWH)	-785	+785	1,576
Marginal Cost (/KWH)			2.5
In BTU/KWH			9,260
Winter Off-Peak			
Marginal Cost (¢/KWH)	-	-	2.4
In BTU/KWH			8,730

Note: These figures exclude variable operation and maintenance expenses of 0.3¢/KWH.

2. Historical Marginal Energy Costs

Where production cost model results are not available, use of historical data as a proxy to forecast future marginal energy costs may be considered. The starting point to estimating historical marginal energy costs is incremental fuel cost (system lambda) data. A number of adjustments to these system lambda costs may be necessary in order to properly calculate marginal energy costs. In low-load periods, production from baseload units or power purchases may be reduced below maximum output levels, while higher cost units are left in operation to respond to minute-to-minute changes in demand. In this instance, the cost of power from the baseload units or purchases with reduced output, not system lambda, represents marginal energy costs. Similarly, in a high-load period, the cost of power from on-line block-loaded peaking units would represent marginal energy cost, even though the cost of these units may not be reflected in the system lambda costs. In a system dominated by peaking hydro, but energy constrained, the cost of production from non-hydro units which serve to "fill the reservoir" represents marginal energy costs.

Another necessary adjustment would be to account for the fixed fuel costs associated with a change in unit commitment when there is a change in load. This fixed fuel cost can be estimated as follows. First, identify how an anticipated change in load affects production scheduling. For example, if production scheduling follows a weekly schedule, an increase in load might increase weekday unit commitment but not impact weekend operations. Second, identify what fraction of time different types of units would be next in line to be started or shut down in response to a change in load. Third, rely on engineering estimates to establish the fixed fuel costs for each type of unit. With this information, the fixed fuel cost adjustment can be estimated by taking the product of the probability of particular units being next in line times the fixed fuel cost for each unit. The fixed fuel cost can be allocated to time period by investigating how changes in load by costing period affect production scheduling. A simple approach would be to identify the probability of different costing periods being the peak, and using these probabilities to allocate fixed fuel costs to costing periods.

B. Allocation of Costs to Customer Group

Marginal energy costs vary among customer groups as a result of differences in the amount of energy losses between generation level and the point in the transmission/distribution system where power is provided to the customer. Energy losses tend to increase as power is transformed to successively lower voltages, so energy losses (and thus marginal energy costs) are greatest for customer groups served at lower voltages. Ideally, energy losses should be time-differentiated and should reflect incremental losses associated with a change in customer usage, rather than average losses, although incremental losses are difficult to measure and are seldom available. Table 9-2 shows marginal energy costs by customer group, taking into account time-differentiated average energy losses for the utility case study. The variation in average marginal energy costs in Table 9-2 is due solely to differences in energy losses, reflecting differences in service voltage among the customer groups.

TABLE 9-2

MARGINAL ENERGY COSTS
BY TIME PERIOD AND RETAIL CUSTOMER GROUP

(¢/KWH, at Sales Level)

	Summer			Winter		
Customer Group	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
Residential	4.18	3.00	2.70	3.68	3.05	2.86
Commercial	4.17	2.99	2.69	3.68	3.05	2.85
Industrial	4.08	2.94	2.64	3.57	2.96	2.80
Agriculture	4.18	3.00	2.70	3.68	3.05	2.86
Street Lighting	4.13	2.97	2.67	3.63	3.01	2.83

II. MARGINAL CAPACITY COSTS

In most utility systems, generating facilities are added primarily to meet the reliability requirements of the utility's customers.[7] These generating facilities must be capable of meeting the demands on the system with enough reserves to meet unexpected outages for some units. System planners employ deterministic criteria such as reserve margin standards (e.g., 20 percent above the forecast peak demand) or probabilistic criteria such as loss of load probability (LOLP) standards (e.g., one outage occurrence in ten years). Whichever approach is used, these standards implicitly reflect how valuable reliability is to utility customers. Customers are willing to pay for reliable service because of the costs that they incur as a result of an outage. More generally, this is referred to as shortage cost, including the cost of mitigating measures taken by the customer in addition to the direct cost of outages. Reasonable reliability standards balance the cost of improving reliability (marginal capacity cost) with the value of this additional reliability to customers (shortage cost).

[7] In some systems that rely heavily on hydro facilities, energy may be a constraining variable rather than capacity. New generating facilities are added primarily to generate additional energy to conserve limited water supplies. In such circumstance, marginal capacity costs are essentially zero.

A. Costing Methodologies

There are two methodologies in widespread use for determining marginal capacity costs, the peaker deferral method and the generation resource plan expansion method. The peaker deferral method uses the annual cost of a combustion or gas turbine peaker (or some other unit built solely for capacity) as the basis for marginal capacity cost. The generation resource plan expansion method starts with a "base case" generation resource plan, makes an incremental or decremental change in load, and investigates how costs change in response to the load change.

1. Peaker Deferral Method

Peakers are generating units that have relatively low capital cost and relatively high fuel costs and are generally run only a few hours per year. Since peakers are typically added in order to meet capacity requirements, peaker costs provide a measure of the cost of meeting additional capacity needs. If a utility installs a baseload unit to meet capacity requirements, the capital cost of the baseload unit can be viewed as including a reliability component equivalent to the capital cost of a peaker and an additional cost expended to lower operating costs. Thus, the peaker deferral method can be used even when a utility has no plans to add peakers to meet its reliability needs. The peaker deferral method measures long-run marginal cost, since it determines marginal capacity cost by adding new facilities to just meet an increase in load, without considering whether the existing utility system is optimally designed. The peaker deferral method compares the present worth cost of adding a peaker in the "test year" to the present worth cost of adding a peaker one year later. The difference is the annual (first-year) cost of the peaker. This cost is adjusted upward since, for reliability considerations, more than one MW of peaker capacity must be added for each MW of additional customer demand.[8] In the utility case study, the installed capital cost of the peaker is $615/KW, resulting in a marginal capital cost of $80/KW. Details on the derivation of this latter figure are provided in Appendix 9-A.

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[8]The peaker deferral method is described in greater detail in National Economic Research Associates, A Framework for Maginal Cost-Based Time-Differentiated Pricing in the United States: Topic 1.3, Electric Utility Rate Design Study, February 21, 1977.

2. Generation Resource Plan Expansion Method

An altemtive approach to developing marginal production cost is to take the utilion resource plan as a base case, and then increment or decrement the load forecast on which the plan was based. An alternate least-cost resource plan is then developed which account the modified load forecast. The resulting revision to the generation resource plan captures the effect of the change in customer usage.[9]

Similar to the peaker deferral method, the annual costs of the base case and revised generation resource plans are calculated, and then discounted to present-worth values. The annual revenue requirements include both capital-related and fuel-related costs, so fuel savings associated with high capital cost generating units are reflected in the analysis. The difference between the present-worth value of the two cases is the marginal capacity cost of the specified change in customer usage.

In the utility case study, the least-cost response to an increase in customer load in the "test year" would result in returning a currently retired generating unit to service one year sooner. The increase in total production cost (capital and fuel costs) associated with this increased load case results in a marginal capacity cost of $21/KW. The derivation of this figure is provided in Appendix 9-A. In contrast to the peaker deferral method, the generation resource plan expansion method measures short-run marginal cost, since it explicitly accounts for the current design of the utility system. In the utility case study, the presence of a temporarily out-of-service generating unit indicates surplus capacity, which accounts for the difference between short-run marginal capacity cost and long-run marginal capacity cost.

B. Allocation to Time Period

LOLP refers to the likelihood that a generating system will be unable to serve some or all of the load at a particular moment in time due to outages of its generating units. LOLP tends to be greatest when customer usage is high. If LOLP in a period is 0.01, there is a one percent probability of being unable to serve some or all customer load. Similarly, if load increases by 100 KW in this period, on average, the utility will be unable to serve one KW of the additional load. Summing LOLP over all periods in a year gives a measure of how reliably the utility can serve additional load.

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[9]The generation resource plan expansion method is described in greater detail in C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, The Marginal Cost and Pricing of Electricity: An Applied Approach, June 1976.

If load increases in an on-peak period when usage is already high, the LOLP-weighted load is high and there is a relatively large impact on reliability which must be offset by an increase in generating resources. If load increases in an off-peak period when usage is low, the LOLP-weighted load is low and there may be relatively little impact on reliability. Similarly, when additional generating resources are added to a utility system, the incremental reliability improvement in each period is proportional to the LOLP in that period. Thus, LOLP's can be used to allocate marginal capacity costs to time periods. A simple example showing the derivation of LOLP and its application to allocating marginal capacity costs to time periods is shown in Appendix 9-B.

An actual allocation of marginal capacity costs to time periods is shown in Table 9-3, based on the utility case study. The LOLP's are based on a probabilistic outage model that takes into account historical forced outage rates, scheduled unit maintenance, and the potential for emergency interconnection support.

TABLE 9-3

ALLOCATION OF MARGINAL CAPACITY COST TO TIME PERIOD

Time Period	Hours	LOLP	Marginal Capacity Cost
Summer On-Peak	12:00 noon - 6:00 p.m.	0.716949	$57.31
Mid-Peak	8:00 a.m. - 12:00 noon		
	6:00 p.m. - 11:00 p.m.	0.124160	9.93
Off-Peak	11:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.002532	0.20
Winter On-Peak	8:00 a.m. - 5:00 p.m.	0.054633	4.37
Mid-Peak	5:00 p.m. - 9:00 p.m.	0.087076	6.96
Off-Peak	9:00 p.m. - 8:00 a.m.		
	and all weekend hours	0.014650	1.17

C. Allocating Costs to Customer Groups

Marginal capacity costs vary by customer group, reflecting differences in losses between generation level and the point where the power is provided to the customer (sales level). Ideally, the loss factors used to adjust from sales to generation level should reflect incremental losses rather than simply reflecting average energy losses, although incremental losses are difficult to measure and are seldom available.

Table 9-4 shows marginal capacity costs by rating period, reflecting losses by customer group, based on the utility case study. This table is constructed for illustration only, by assuming that each customer group's usage is constant for all hours within the rating periods shown. In actuality, the revenue allocation described in Chapter 11 uses hourly customer group loads and hourly LOLP data to calculate hourly marginal capacity costs by customer group.

TABLE 9-4

AVERAGE MARGINAL CAPACITY COSTS BY RATING PERIOD AND RETAIL CUSTOMER GROUP

($/KW month)

	Summer (4 Months)			Winter (8 Months)			
Customer Group	**On-Peak**	**Mid-Peak**	**Off-Peak**	**On-Peak**	**Mid-Peak**	**Off-Peak**	**Annual**
Residential	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Commercial	15.79	2.72	0.06	0.60	0.96	0.16	87.96
Industrial	15.46	2.67	0.06	0.59	0.94	0.16	86.12
Agriculture	15.86	2.74	0.06	0.60	0.96	0.16	88.32
Street Lighting	15.69	2.71	0.06	0.60	0.95	0.16	87.36

In general, all customers receive the same level of reliability from the generation system, since it is seldom practical to provide service at different reliability levels. Sometimes customers are served under interruptible tariffs or have installed load management devices, however, which effectively provide a lower reliability service. The marginal capacity cost for these customers may be zero if the utility does not plan for, or build, capacity to serve the incremental load of these customers. If the utility continues to plan for serving these customer loads, but with a lower level of reliability, the marginal capacity cost for these customers is related to the marginal capacity cost for regular customers by their relative LOLP's.

APPENDIX 9-A

DERIVATION OF MARGINAL CAPACITY COSTS USING THE PEAK DEFERRAL AND GENERATION RESOURCE PLAN EXPANSION METHODS

This appendix provides an example of the application of the peaker deferral method and the generation resource plan expansion method to calculating marginal capacity cost.

A. Peaker Deferral Method

The peaker deferral method is described in greater detail in Topic 1.3 of the Electric Utility Rate Design Study, A Framework for Marginal Cost-Based Time-Differentiated Pricing in the United States (National Economic Research Associates, February 21, 1977). This method begins with a forecast of the capital and operating costs of a peaker.

Based on the capital and operating costs of a peaker, a future stream of annual revenue requirements is forecast over the expected life of the peaker and its future replacements. Next, this stream of annual revenue requirements is discounted to a single present-worth value using the utility cost of capital.[10] Next, the annual stream of revenue requirements is shifted forward assuming that construction of the peaker and its future replacements is deferred one year, and the resulting stream of revenue requirements is discounted to a single present-worth value. The difference between these two present-worth values is the deferral value -- the "cost" of operating a peaker for one year. Finally, this deferral value must be scaled upward to reflect that a peaker is not perfectly reliable, and may not always be available to meet peak demands. This can be done by comparing the reliability improvement provided by a "perfect" resource (one that is always available) to the reliability improvement provided by a peaker. This ratio, sometimes called a capacity response ratio (CRR), is then multiplied by the peaker deferral value to calculate marginal capacity cost.

[10]Arguably, a ratepayer discount rate may be more appropriate than the utility's cost of capital. Due to the difficulty of developing a ratepayer discount rate, utility cost of capital is commonly employed for discounting. The cost of capital should be based on the cost of acquiring new capital. This will generally differ from the authorized rate of return, which reflects the embedded cost of debt financing.

A calculation of marginal capacity cost using the peak deferral method is illustrated in Table 9A-1, based on the utility case study. The calculation starts with the installed capital cost of a combustion turbine, including interconnection and appurtenant facilities and capitalized financing costs, of $614.97/KW.

TABLE 9A-1

DEVELOPMENT OF MARGINAL PRODUCTION COST USING THE PEAKER DEFERRAL METHOD

Line No.	Item	$/KW
1	Peaker Capital Cost	614.97
2	Deferral Value (Line (1) x 10.07%)	61.93
3	Operation and Maintenance Expense	6.39
4	Fuel Oil Inventory Carrying Cost	1.19
5	Subtotal (Line (2) + Line (3) + Line (4))	69.51
6	Marginal Capacity Cost (Line (5) x 1.15)	79.94

This initial capital investment (line 1) is then multiplied by an economic carrying charge of 10.07 percent to give the annual deferral value of the peaker (line 2). The economic carrying charge is conceptually similar to the levelized carrying charge which is frequently used in evaluating utility investments. While a levelized carrying charge produces costs which are level in nominal dollars over the life of an asset, the economic carrying charge produces costs which are level in inflation-adjusted dollars.[11] The economic carrying charge is the product of three components, as shown in the following equation:

Economic carrying charge = revenue requirement present-worth factor
x infinite series factor
x deferral value factor

The revenue requirement present-worth factor is calculated based on the initial capital investment as follows. A projection of annual revenue requirements associated with the $614.97/KW initial investment is made for the life of the investment. Included

[11]The development of the economic carrying charge in this section ignores the effect of technological obsolescence. The effect of incorporating technological obsolescence would be costs that decline over time (in inflation-adjusted dollars) at the rate of technological obsolescence (see Attachment C, "An Economic Concept of Annual Costs of Long-Lived Assets" in National Economic Research Associates, *op. cit.*).

in these annual revenue requirements are depreciation, return (using the cost of obtaining new capital), income taxes, property taxes, and other items which may be attributed to capital investment. These annual revenue requirements are then discounted using the utility's cost of capital, producing a result perhaps 30 to 40 percent above the initial capital cost, depending largely on the utility's debt-equity ratio and applicable tax rates. The ratio of the discounted revenue requirements to the initial capital investment is the revenue requirement present-worth factor.

The next component in the economic carrying charge calculation increases the discounted revenue requirements to reflect the discounted value of subsequent replacements. The simplest approach is to use an infinite series factor. Assuming that capital costs rise at an escalation rate i, that the utility cost of capital is r, and that peakers have a life of n years, the formula is as follows:

$$\text{Infinite Series Factor} = \frac{1}{1 - \left(\frac{1+i}{1+r}\right)^{n}}$$

The final component of the economic carrying charge is the deferral value factor. If the construction of the peaker is deferred by one year, each annual revenue requirement is discounted an additional year, but is increased due to escalation in the capital cost of the peaker and its replacements. The value of deferring construction of the peaker for one year is given by the difference between the discount rate and the inflation rate, expressed in original year dollars, as follows:

$$\text{Deferral Value Factor} = \frac{r-i}{1+r}$$

The next step in the calculation of marginal capacity cost is to add annual expenditures such as operation and maintenance expenses (line 3), and the cost of maintaining a fuel inventory (line 4). Finally, the subtotal of these expenses (line 5) is multiplied by a capacity response ratio, accounting for the reliability of the peaker compared with a perfect capacity resource, to give the marginal capacity cost (line 6).

The peaker deferral method produces a measure of long-run marginal cost, since it measures the cost of changing the utility's fixed assets in response to a change in demand, without taking into account a utility's existing capital investments.

Using a probabilistic outage model, loss of load probability (See Appendix 9-B) can be used to adjust long-run marginal costs developed from a peaker deferral method to reflect short-run marginal costs. This is accomplished by multiplying the marginal capacity cost from the peaker deferral method times the ratio of forecast LOLP to the LOLP planning standard. This can be seen in the following example. If the LOLP planning standard is 0.0002, then a 10,000 KW increase in demand will, on average, result in an expected 2 KW being unserved. Since this is the planning standard, the value to consumers of avoiding these 2 KW being unserved is just equal to the cost of adding an addiin demand will, on average, result in 1 KW being unserved. Adding an additional resource would benefit consumers, but only an expected 1 KW of unserved demand would be avoided. Thus, the benefit of avoiding the 1 KW of unserved load is one-half the cost of the additional resources necessary to serve this load. In this example, short-run marginal capacity cost is one-half the long-run marginal capacity cost.

B. Generation Resource Plan Expansion Method

The generation resource plan expansion method is described in greater detail in The Marginal Cost and Pricing of Electricity: An Applied Approach (C. J. Cicchetti, W. J. Gillen, and Paul Smolensky, June 1976). This method begins with the utility's current least-cost resource plan, increments or decrements load in the "test year" by some amount, and revises the least-cost resource plan accordingly. The present-worth cost of the two resource plans, including both capital and fuel costs, are compared, and the difference represents the marginal capacity cost for the chosen load increment.

The generation resource plan expansion method can be illustrated using the utility case study. In this case study, the utility has adequate resources to serve loads and, in addition, has surplus oil/gas units which are expected to be refurbished and returned to service to meet future load requirements. If load were to increase above forecast, this would accelerate the refurbishment of these units. For example, if load increased 200 MW, the refurbishment and return to service of a 225 MW unit would be advanced one year. The cost of this refurbishment is about $30 million and would result in perhaps a 15-year life extension. For simplicity, the annual cost of accelerating the capacity requirement is computed using the same economic carrying charge approach as developed above for the deferral of a peaker as follows:[12]

$$\text{Annual Cost (\$/KW)} = \frac{\text{(Capital Cost) x (Economic Carrying Charge)}}{\text{(Load Increment)}}$$

$$= \frac{(\$30{,}000{,}000) \times (0.1407)}{(200{,}000 \text{ KW})}$$

$$= \$21/\text{KW}$$

[12]The economic carrying charge is actually higher since the 15-year life extension is shorter than the expected 30-year life of the peaker. It would be more precise to identify the replacement capacity for the refurnished unit in the resource plan when it is eventually retired after 15 years, and take into consideration the effect of acclerating the unit's return to service on this furture replacement.

This annual cost should be reduced by the annual benefit of any fuel savings resulting from the accelerated return to service of the unit. However, a production cost model analysis shows that there are virtually no fuel savings from returning the unit to service, since its operating costs are about the same as for the oil/gas units already in service.

In implementing this generation resource plan method, care must be taken to choose load increments that do not lead to lumpiness problems. If the load increment is small, there may not be an appreciable impact on the generation resource plan. On the other hand, a modest load change may be sufficient to tilt the scales toward a new generating resource plan, overstating the effect of the load change in general. One approach to dealing with potential lumpiness problems is to investigate a series of successive load increments, and then take an average of the marginal capacity costs determined for the successive increments.

Comparing this result with the peaker deferral method, the utility's short-run marginal capacity cost of $21/KW is about 26 percent of the long-run marginal capacity cost of $80/KW associated with meeting the capacity requirements by adding new generating facilities.

APPENDIX 9-B

A SIMPLE EXAMPLE OF THE DERIVATION OF LOSS OF LOAD PROBABILITIES

This appendix provides a simple example of how LOLP is developed and used to allocate marginal capacity costs to time periods. In the example shown in Table 9B-1, there are two time periods of equal length: an on-peak period where load is 250 MW and an off-peak period where load is 150 MW. The utility has four generating units totaling 600 MW, with various forced outage rates. Table 9B-1 calculates the probability of each combination of the four units being available. For example, there is a 0.0004 probability that all of the units are out of service simultaneously. Similarly, there is a 0.0324 probability that Units C and D are available (0.9 probability that each unit is available) while Units A and B are not available (0.1 probability that each unit is in a forced outage). Thus, there is a 0.0004 probability that the utility would be unable to serve any load, a 0.0076 probability that the utility would be unable to serve loads above 100 MW, a 0.0432 probability that the utility would be unable to service loads above 200 MW, and so forth. When load is 150 MW in the off-peak period, the utility will be unable to serve this load if all four units are not available, if only Unit C is available, or if only Unit D is available. The probability of these events occurring is 0.0076. Similarly, the probability of being unable to serve the 250 MW load in the on-peak period is 0.0432. The overall LOLP is 0.0508, with 85 percent of this LOLP resulting from the on-peak period. Thus, 85 percent of the marginal capacity costs are allocated to the on-peak period and 15 percent to the off-peak period.

TABLE 9B-1
LOSS OF LOAD PROBABILITY EXAMPLE

Resources:

Size	Forced Outage Rate	Expected Availability
A: 200 MW	20%	80%
B: 200 MW	20%	80%
C: 100 MW	10%	90%
D: 100 MW	10%	90%

Probabilities:

Units	MW Available	Cumulative Available Probability	
None	0	(.2)(.2)(.1)(.1)=0.0004	0.0004
C	100	(.2)(.2)(.9)(.1)=0.0036	0.0040
D	100	(.2)(.2)(.1)(.9)=0.0036	0.0076
A	200	(.8)(.2)(.1)(.1)=0.0016	0.0092
B	200	(.2)(.8)(.1)(.1)=0.0016	0.0108
C, D	200	(.2)(.2)(.9)(.9)=0.0324	0.0432
A, C	300	(.8)(.2)(.9)(.1)=0.0144	0.0576
A, D	300	(.8)(.2)(.1)(.9)=0.0144	0.0720
B, C	300	(.2)(.8)(.9)(.1)=0.0144	0.0864
B, D	300	(.2)(.8)(.1)(.9)=0.0144	0.1008
A, B	400	(.8)(.8)(.1)(.1)=0.0064	0.1072
A, C, D	400	(.8)(.2)(.9)(.9)=0.1296	0.2368
B, C, D	400	(.2)(.8)(.9)(.9)=0.1296	0.3664
A, B, C	500	(.8)(.8)(.9)(.1)=0.0576	0.4240
A, B, D	500	(.8)(.8)(.1)(.9)=0.0576	0.4816
A, B, C, D	600	(.8)(.8)(.9)(.9)=0.5184	1.0000

Time Period Demand:

		LOLP	
On-Peak	250 MW	0.0432	85%
Off-Peak	150 MW	0.0076	15%
		0.0508	

CHAPTER 10

MARGINAL TRANSMISSION, DISTRIBUTION AND CUSTOMER COSTS

In contrast to marginal production costing methodology, analysts have devoted little attention to developing methodologies for costing marginal transmission, distribution and customer costs. An early evaluation noted: "... the determination of marginal costs for these functions, and especially distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort."[1] The referenced study, therefore, used average embedded costs, because they were both more familiar to ratemakers and analysts, and a reasonable approximation to the marginal costs. It is still common for analysts to use some variation of a projected embedded methodology for these elements, rather than a strictly marginal approach. While marginal cost concepts have been applied to transmission and distribution for the purpose of investigating wheeling rates, little of this analysis has found its way into the cost studies performed for retail ratemaking. The basic research into marginal costing methodologies for transmission, distribution and customer costs for retail rates was done in connection with the 1979-1981 NARUC Electric Utility Rate Design Study and most current work and testimony still refer back to those results.

I. TRANSMISSION

There are several basic approaches to the calculation of the marginal cost of transmission. However, the first step in any approach is the definition of the study period. Transmission investments are "lumpy" in that they usually occur in large amounts at intervals. Therefore, it is important to select a study horizon that is long enough to reflect the relationship between investments and load growth. To the extent that investments are related to load growth occurring outside the study period or there is

[1] J. W. Wilson, Report for the Rhode Island Division of Public Utilities, Public Utilities Commission and Governor's Energy Office (1978), pp. B-27-8.

a significant change in the level of system reliability, the analyst may wish to adjust the calculation of the load growth to identify the investment more closely with the load it is intended to serve. Given the desirability of a fairly long study period, analysts will typically select the utility's entire planning period augmented by historical data to the extent that the analyst believes that the historical relationships will continue to obtain in the future.

For purposes of a marginal cost study, investment in the transmission system is generally assumed to be driven by increments in system peak load. As the transmission system was actually constructed for a variety of reasons, the second step in the calculation of the marginal cost of transmission is to identify and eliminate those investments that are not related to load growth. The non-demand related transmission investments can be categorized as:

1. Those related to remote siting of generation units (which are costed as part of the generation cost).
2. Those related to system interconnections and pool requirements (whose benefits are manifested in reduced reserve requirements and, therefore, are again costed with generation).
3. Those associated with large loads of individuals (which are therefore charged to the particular customer concerned).
4. Replacement of existing facilities without adding capacity to serve additional load (assuming that the economic carrying charge formula incorporates an infinite series factor).

Costs that remain should be related only to system load growth or to maintenance of system reliability.

A. Costing Methodologies

There are two basic approaches to estimating marginal transmission costs, and they begin to diverge at this step in their methodology. The first approach is the Projected Embedded Analyses of which there are two variations: the Functional Subtraction approach, which relates total transmission investment additions to load growth, and the Engineering approach, which relates individual facilities (line miles, transformers, etc.) to load growth. The second methodology is the System Planning approach, which uses a base case/decrement analysis.

1. Projected Embedded Analyses

As the name suggests, Projected Embedded Analyses are often based on a simple projection of past costs and practices into the future. A disadvantage of this approach is that it may fail to capture important technological and business related developments and therefore result in the over or underestimation of marginal capacity cost.

- Functional Subtraction Approach

The Functional Subtraction approach requires data in the form of annual load related investments in transmission and load growth for the same period. The period to be analyzed includes the transmission planner's planning period plus whatever historical period he believes appropriate. Transmission cost data must be sufficiently specific to enable the analyst to differentiate load growth related transmission expenditures from those more properly associated with either generation or a specific customer. Having chosen the study period and identified the load related investments in transmission by voltage level, the analyst performs the analysis in real dollars. This is done by converting the historical nominal data to current money values by applying either the Handy-Whitman plant costs indices or, if available, an inflation index particular to the utility. Projected investments are converted to real dollars by removing the inflation factor used by the planner in his computations.

The third step is to relate the real transmission investments to a measure of load growth at each voltage level, weather normalized if possible, stated in kilowatts. Non-coincident peak demand on the transmission system is the correct measure of load growth. However, given the system's integrated nature, for most purposes non-coincident peak demand on the transmission system is the same as the total system coincident peak.

The relationship between investment and load growth ($/KW) is usually obtained by simply dividing the sum of investments for the period by the growth in peak load. There have been some attempts at regressing annual investments against load growth, using the equation Transmission Costs = a + b (peak demand), but the R^2's have been disappointingly low. However, given the assumption that transmission investments are "lumpy" and that one particular year's investment is not specifically related to that year's load growth, the lack of correlation should not be surprising. The best regression results are achieved by using least squares and regressing cumulative incremental investment against cumulative incremental load. Thus, the first year observation is the first year value of incremental investment and load, the second year observation is the sum of the first year and the second year values, the third year is the sum of the values for the first three years, and so on. See Table 10-1.

TABLE 10-1
Computation of Marginal Demand Cost of Transmission
Transmission-Related Additions to Plant
Per Added Kilowatt of Transmission System Peak Demand
(Functional Subtraction Approach)

Year	(1) Growth Related Net Addition (1988 $M)	(2) Cumulative Net Addition (1988 $M)	(3) Growth In System Peak (MW)	(4) Cumulative System Peak (MW)
Actual				
1976	44.1	44.1	888	888
1977	33.8	78	166	1054
1978	40	118	750	1804
1979	30	147.9	467	2271
1980	36.4	184.3	148	2419
1981	30.6	214.9	808	3227
1982	134.2	349.1	(538)	2689
1983	62.7	411.8	295	2984
1984	42.5	454.3	1685	4669
1985	148.3	602.6	(579)	4090
Projected				
1986	188.6	791.2	21	4111
1987	71.4	862.6	302	4413
1988	178.5	1041	446	4859
1989	83.6	1124.7	406	5265
1990	128.7	1250.4	407	5672
Total:	1250.4		5672	

Simplified Approach

Marginal Transmission Investment Costs = Column 1 Total/Column 3
Total = $220.45/KW

Regression Approach

Marginal Transmission Investment Costs = $249.40/KW

Y = A + B*X
Where Y is cumulative demand-related net additions to plant
X is cumulative additions to coincident peak demand.

A = -326.59
B = 0.2494

R^2 = 0.84

The fourth step is to convert the per kilowatt investment cost into an annualized transmission capacity cost by multiplying the former by a carrying charge rate. There are two forms in common use, the economic carrying charge and the standard annuity formula. During a period of zero inflation the two methods produce the same results, but during inflationary periods only the former takes due account of the impact of inflation on the value of plant assets.[2]

Since the addition of transmission capacity occasions increased operation and maintenance expenses, the marginal 0&M costs are calculated and added to the annualized transmission capacity costs. The expense per KW is usually found to be fairly constant and either the current year's expense or the average of the $/KW in current dollars over the historical portion of the study period is considered to be a good approximation of the marginal transmission operation and maintenance expense. The analyst takes the data from the FERC Form I, again being careful to include only those costs related to load growth. For example, he may exclude rents or that portion of expenses related to load dispatching associated with generation trade-offs. Total transmission 0&M expenses in current dollars are divided by system peak demand, and averaged if multiple years have been used. The result, either for the single current year or the average of several years, is then added to the annualized transmission capacity cost to obtain the total transmission marginal cost. Alternatively, 0&M expenses can be regressed on load growth or transmission investments, in which case the 0&M adjustment appears as a multiplier to the capacity cost rather than an adder.

The final step is to adjust the results for transmission's share of indirect costs including the marginal effect on general plant and working capital. See Table 10-2.

TABLE 10-2
Computation of Marginal Demand Costs of Transmission
(1988 $)

Description	Cost Per KW ($)
Transmission Investment per KW Change in Load (from Table 10-1)	249.40
Annual Costs (*10.9%)	27.18
Demand Related O&M Expense	4.52
General Plant Loading	1.05
Working Capital	0.48
Total Annual Cost of Transmission	33.23
Loss Adjustment (1.033)	34.33

[2]See Appendix 9-A for the derivation of the economic carrying charge.

- Engineering Approach

Like Functional Subtraction, the Engineering approach also relates changes in transmission investment to changes in system peak load. However, it first relates the addition of specific facilities (line miles, transformers, etc.) to growth in load over the chosen study period, and then computes the unit costs of each facility to derive the investment for transmission per added kilowatt of demand. The method has the advantage of more readily identifying those facilities added for the purpose of serving added load (and thereby excluding non-load related investment). It may be more difficult to apply, however, as it requires detailed records and distinctions that may come more easily to the utility company planner than to the outside observer.

Once the study period is selected, the analyst identifies the load growth related facilities that were or will be added each year at each voltage level. By either regression analysis or simple averages, the addition of facilities is related to the growth in coincident system peak. The result is expressed in line miles, transformers, etc. per added KW and monetized by applying a cost figure for each facility in real dollars. As with Functional Subtraction, the investment per added demand is annualized by a levelized carrying charge, or, more properly, an economic carrying charge (consistent with calculations for the other capacity components) and added to the associated annual operation and maintenance costs. The costs per KW for each facility are then totaled at each voltage level and adjusted for indirect costs.

2. The System Planning Approach

The System Planning approach is more nearly related to the marginal costing methodologies for generation than is the Projected Embedded approach. As such, it may be helpful to review what is meant by marginal capacity cost. The marginal cost of transmission or distribution capacity can be defined as the present worth of all costs, present and future, as they would be with a demand increment (decrement), less what they would be without the increment (decrement). This definition of marginal cost can be represented by a time-stream of discounted annual difference costs stretching to infinity. The stream of investments from this approach would be annualized by using an economic carrying charge.

Alternatively, the marginal capacity cost can be interpreted as the cost to the utility of bringing forward (delaying) by one year its future investments, including the stream of replacement investments, to meet the demand increment (decrement). Mathematically, this interpretation results in annual charges equal to the economic carrying charge on the marginal investments.

In order to simplify the calculation of marginal capacity cost it is common for the stream of difference costs to be truncated after a set number of years, usually the utility's planning period or the average economic life of the investments. However, if the period chosen is too short, truncation can result in serious underestimation of marginal capacity cost. In terms of the second definition this would be equivalent to neglecting the impact of the increment (decrement) on more distant investments. Truncating a component of the economic carrying charge as discussed in Appendix 9-A will mitigate some of those effects.

The System Planning approach is an application of the first incremental/decremental definition of marginal capacity cost and therefore the analyst should take care not to base his calculations on an unreasonably short planning horizon.

In contrast to the projected embedded studies for transmission cost, which may use some historical data, the study period for the system approach is forward-looking. As with the other methodologies, the relevant costs are those related to changes in load, and coincident system peak is the basic cost causation factor. The data required is thus the planner's base case of expected load growth and transmission investments, plus an incremental (decremental) case for the same period.

Planned transmission costs, investment and expenses, are identified and the marginal cost quantified by developing a differential time series of expenditures over the planning horizon using an increment or decrement to system peak load. A base case expansion plan is developed using the forecasted load over the future planning horizon. Investments are separated by voltage level where the utility has customers who take service directly from the high voltage lines. Those investments associated with load growth are identified and the total annual revenue requirements (including expense items) are derived in real or nominal dollars for each year at each voltage level.

The system planner is then asked to assume an increase or decrease in the coincident peak load and redesign transmission expenditures, still maintaining system reliability and continuing to meet the system planning criteria, and repeat the costing procedure. Thus, the marginal transmission capacity cost is the change in total costs associated with changes to budgeted transmission expenditures between the planner's base case and his incremental (decremental) case. The dollar stream representing the difference between the two cases is present worthed, aggregated and then annualized over the costing horizon. The resultant annualized figure is then divided by the amount of the increment (decrement) to obtain a $/KW marginal cost for transmission for each voltage level. The size of the increment (decrement) may vary according to the size of the utility and will certainly affect the result. A 50 MW change is often chosen as the smallest (most marginal) change that can be assumed and produce measurable differentiated cases.

3. Adjustments

- Loss Adjustment

Electric utility transmission and distribution systems are not capable of delivering to customers all of the electricity produced at the generation bus bar. The difference between the amount of electricity generated and the amount actually delivered to customers is called "losses".

Losses can be broadly classified as copper losses, core losses and dielectric losses. They are caused, respectively, by the production of heat, the establishment of magnetic fields and the leakage of current. The first of these varies in proportion to the square of the current and is therefore included under marginal energy costs. The latter two are fixed losses associated with specific equipment and therefore covered by marginal capacity costs.

Marginal capacity loss factors are applied to marginal capacity-related costs per kilowatt. These factors account for the fact that when a customer demands an additional kilowatt at the meter, more than a kilowatt of distribution, transmission and generation capacity must be added.

- Energy Adjustment

While most analysts assume that transmission is causally related to system peak and therefore is totally demand related, it has been argued, particularly in the literature concerning wheeling rates, that transmission embodies an energy component as well. For very small changes in load, transmission and generation are substitutes: additional generation can overcome the line losses in the transmission system, or extra transmission capacity can, by reducing losses, substitute for added generation. Thus, conceptually, it is proper to net out the energy savings from the marginal investment cost of transmission, leaving the residual to be demand related. There is no accepted methodology for quantifying this adjustment. One approach is to obtain a calculation of the energy loss/potential savings in $/period by multiplying the cost of 1 KW for each costing period times the energy loss in that period. Summing across the periods produces, in total dollars per kilowatt-year, the avoidable loss/potential savings. As some of this loss occurs at the generation level, it is appropriate to net out the portion of energy loss due to generation. The remainder is net energy savings in $/KW year attributable to increased transmission capacity that can then be capitalized into a $/KW computation.

B. Allocation of Costs to Time Periods

The attribution of marginal demand-related costs by time of use reflects the system planner's response to the goal of maintaining a target level of reliability in the generation, transmission and distribution components of the system. Thus, as the load varies according to time periods, so does the need to add capacity to maintain reliability. System planners evaluate generation, transmission and distribution components separately for their reliability, and ideally the transmission capacity cost responsibility would reflect the planner's sensitivity to such factors as the likelihood of weather related service disruptions. For costing purposes, however, most analysts use the same methodologies, and often the same attribution factors, for transmission as they do for generation. The reasoning is that in general the load characteristics of the transmission system are identical to those of the generation system, both being driven by the system coincident peak. Therefore, it is not considered necessary to perform transmission specific load studies as the results of such studies should not differ significantly from those of the generation load studies. To the extent that the transmission and generation load characteristics do differ, the methodology discussed under "Distribution" can be employed.

The methods employed, include attributing the costs uniformly across the peak period, or by means of transmission reliability indicies or loss of load probability (LOLP). However, where the LOLP data are heavily influenced by seasonal generation availability (e.g., hydro facilities) or generation maintenance schedules, the generation LOLP factors are not a good measure of the need to add transmission capacity.

None of the generation-tied allocation methods recognize the seasonal variation in the capability of transmission facilities. Transmission facilities have a lower carrying capability when ambient temperatures are high (i.e., summer). Therefore, winter peaking utilities and summer peaking utilities with significant winter peaks need some method for adjusting seasonal assignment factors if they are going to rely on generation related costing allocators for transmission.

II. DISTRIBUTION

A. Costing Methodologies

The major issue in establishing the marginal cost of the distribution system is the determination of what portion of the costs, if any, should be classified as customer related rather than demand and energy related. The issue is a carry-over of the unresolved argument in embedded cost studies with the added query of whether the distribution costs usually identified as customer related are, in fact, marginal.

Most analysts agree that distribution equipment that is uniquely dedicated to individual customers or specific customer classes can be classified as customer rather than demand related. Customer premises equipment (meters and service drops) are generally functionalized as customer rather than distribution costs and, in reality, this is the only equipment that is directly assignable for all customers, even the smallest ones. Beyond the customers' premises, however, there are distribution costs that may be classified as customer related. For example, some jurisdictions classify line transformers as customer-related often using a proxy based on average load as the allocation factor when this equipment is not uniquely dedicated to individual customers. In addition, for very large customers, more than merely meters, services, and transformers are directly assignable. Some have entire substations dedicated to them. As noted above in "Transmission," distribution costs of equipment dedicated to individual customers can be directly assigned to them, thus reducing the common distribution costs assigned to the remainder of the class.

The major debate over the classification of the distribution system, however, concerns the jointly used equipment rather than the dedicated equipment. At the margin, there is symmetry between the cost of adding one customer and the cost avoided when losing one customer. A number of analysts have argued, and commissions have accepted, that the customer component of the distribution system should only include those features of the secondary distribution system located on the customer's own property. Portions of the distribution system that serve more than one customer cannot be avoided should one customer cancel service. Similarly, if the customer component of the marginal distribution cost is described as the cost of adding a customer, but no energy flows to the system, there is no reason to add to the distribution lines that serve customers collectively or to increase the optimal investment in the lines that are carrying the combined load of all customers. Therefore, the marginal customer cost of the jointly used distribution system is zero.

Those analysts who believe that there is a significant customer component to the marginal cost of the jointly used portion of the distribution system argue that the distribution system is causally related to increases in both the number of customers and the kilowatts of demand. (They may also note that distribution costs are influenced by the concentration of such non-demand, non-customer factors as load, geographic terrain, climatic conditions and local zoning ordinances. However, no analyst has attempted to introduce and quantify these elements in a marginal cost of service study and absent area-specific rates depending on density and distance from load centers, there is no reason to do so.) Because of the non-interconnected character of the distribution system, the relevant demand parameter is non-coincident peak, preferably measured at the individual substation or even at lower voltages, rather than the system peak used for generation and transmission. This reflects the fact that each portion of the distribution network must be planned to serve the maximum load occurring on it and the utility's investment reflects the need to provide capacity to each separate load center. As some customers receive service directly from the primary distribution system, calculations must be performed separately for the different voltage levels.

The measured relationship for each voltage level is expressed by the equation:

Total Distribution Cost = a + b x demand on distribution + c x customers

The statistical difficulty with this equation is that the demand is highly correlated with the number of customers (multicollinearity) and that therefore it is not possible to identify the separate marginal effects of changes in demand and customers on cost. The proposed estimation techniques resolve the statistical dilemma by computing the customer responsibility separately and then relating the residual cost to load growth. To the extent that the distribution system is sized in part to reduce energy losses, an energy component must also be netted out of marginal cost in order to obtain the demand component.

The two most common approaches to calculate the customer related component in marginal as well as embedded studies are the zero intercept method and the minimum grid calculation. The zero intercept method re-defines the original equation to read:

Total Distribution Cost = a + b x demand on distribution

It solves the multicollinearity problem by eliminating the customer variable under the hypothesis that the constant "a" will then represent the non-variable, non-demand related portion of the costs, or the distribution facilities required when demand is zero. The method has been accused of "solving" the problem of multicollinearity by mis-specifying the equation. Statistically, removing a correlated variable (customers) from the equation will result in transferring some of the responsibility of the omitted variable to the coefficient of the remaining variable (demand). Application of the technique does not necessarily lead to results that make economic sense: negative constant terms are not uncommon. The approach is somewhat more successful when used to analyze cross-sectional data where the correlation is weaker or when applied to individual items of distribution equipment.

The minimum grid approach re-designs the distribution system to determine the cost in current year dollars of a hypothetical system that would serve all customers with voltage but not power (or with minimum demand of 0.5 KW), yet still satisfy the minimum standards for pole height and efficient conductor and transformer size. The calculations can be based either on the system as a whole or on a sample of areas reflecting different geographical, service and customer density characteristics.

When applying this approach, it is necessary to take care that the minimum size equipment being analyzed is, in fact, the minimum-sized equipment available, and not merely the minimum size stocked by or usually installed by the company. To the degree that the equipment being costed is larger than a true minimum, the minimum grid calculation will include costs more properly allocated to demand.

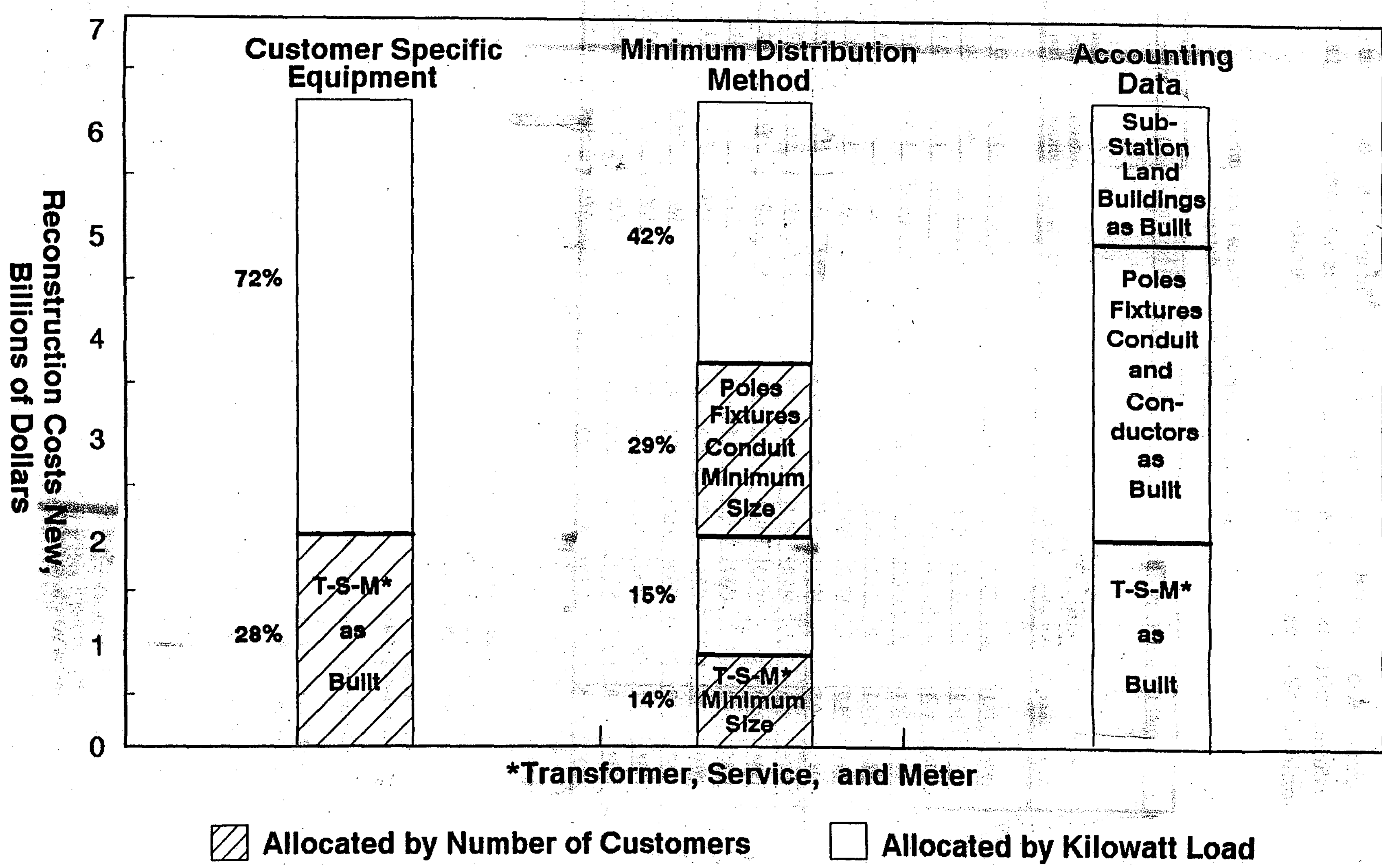
Figure 10-1 illustrates the results of the minimum grid approach for the marginal customer-related cost for a typical residential customer of the sample utility. In column 1 (Customer Specific Equipment) only line transformers, service and meters are functionalized to the customer category while all other distribution equipment is functionalized to the demand category. In column 2 (Minimum Distribution Method) all distribution equipment is first estimated at minimum size and functionalized as customer-related. The additional cost of equipment, sized to meet actual expected loads is functionalized as demand-related. For comparison, column 3 reflects the reconstruction cost for the as-built system. In the sample company, the minimum grid approach to determining the marginal customer-related cost of connecting an average customer produces a customer charge equal to 43 percent of costs of the distribution system (14 percent plus 29 percent) compared to the charge resulting from the alternative T-S-M approach, i.e., restricted to meter, service, line transformer and associated costs, which is only 28 percent of the distribution system costs.

The marginal demand related distribution costs are calculated in a manner similar to the marginal demand related transmission costs. The major differences are that, if considered appropriate, the marginal customer costs must be removed from the total costs incurred during the study period, and that the relevant load growth is non-coincident peak.

Removal of customer costs can be done in two ways. The cost of the minimum grid can be divided by the number of customers served to obtain a cost per customer to be included in the customer charge. The cost per customer at each voltage level can be multiplied by the number of customers added at each voltage level during the study period, and the sum subtracted from the total distribution investment in current year dollars. This residual is then considered the demand (or demand and energy) component of the marginal cost. Alternatively, the marginal customer costs can be removed by using a factor based on the ratio of investment in the minimum distribution grid to the investment in

Figure 10-1

DIFFERING VIEWS OF THE ELECTRIC DISTRIBUTION SYSTEM



the total distribution system, calculated over the historical period. In the example, the customer related portion of the distribution system is 43 percent leaving a demand related portion of 57 percent. See Table 10-3, Column k footnote.

Table 10-3A
Demand Related Marginal Costs of Distribution
Minmum Grid Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Year	Lines	T-M-S	Total Lines	Total Repl.	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Demand Related Portion	Cumul. Demand Related Portion	Cumul. Non-Coin. Peak Load Additions
1976	47.1	30.6	77.7	31.0	46.7	0.9	13.4	61.0	1.820	111.0	63.3	63.3	1078
1977	58.8	56.4	115.2	48.4	66.8	0.3	-13.0	54.1	1.675	90.6	51.7	114.9	1280
1978	58.5	63.6	122.1	44.8	67.3	0.6	7.3	75.2	1.696	127.5	72.7	187.6	2191
1979	68.1	69.7	137.8	55.1	82.7	0.5	12.3	95.5	1.422	135.8	77.4	265.0	2758
1980	73.5	56.0	132.5	82.1	50.4	0.3	18.8	69.5	1.319	91.7	52.3	317.3	2937
1981	94.0	73.2	167.2	103.7	63.5	2.2	22.2	87.9	1.197	105.2	60.0	377.3	3919
1982	90.5	65.2	155.7	96.5	59.2	0.4	31.1	90.7	1.101	99.9	56.9	434.2	3265
1983	76.6	71.6	148.2	99.3	48.9	0.0	31.6	80.5	1.079	86.9	49.5	483.7	3623
1984	91.0	104.3	195.3	130.9	64.4	3.5	23.0	90.9	1.071	97.4	55.5	539.2	5670
1985	138.8	114.0	252.8	169.4	83.4	4.3	17.7	105.4	1.092	115.1	65.6	604.8	4966
1986	153.1	106.5	259.6	174.0	85.6	11.8	76.4	173.8	1.071	186.1	106.1	710.9	4992
1987	158.7	108.2	266.9	178.8	88.1	2.1	70.5	160.7	1.038	166.8	95.1	806.0	5359
1988	161.1	108.9	270.0	178.2	91.8	0.0	31.5	123.3	1.000	123.3	70.3	876.3	5900
1989	159.6	107.7	267.3	173.7	93.6	0.5	19.1	113.2	0.961	108.8	62.0	938.3	6393
1990	168.3	113.6	281.9	186.1	93.8	1.9	26.3	122.0	0.925	114.7	65.4	1,003.6	6888

Regression Results: Y = A + B * X

Where Y is cumulative demand-related net additions to plant and X is cumulative additions to distribution level peak demand.

A = -134.608
B = 0.1591260869

Marginal demand costs of distribution = $159.13

(a) from study workpapers
(b) from study workpapers
(c) a + b
(d) from study workpapers: total replacements (repl.) portion of Lines and T-M-S
(e) c - d
(f) from stduy workpapers
(g) from study workpapers
(h) e + f + g
(i) Handy Whitman index
(j) h * i
(k) j * 57% (43% customer related derived from the average ratio of the mininum distribution system cost to total distribution system costs calculated in study workpapers).
(l) cumulates k
(m) cumulates peak Load additions in study workpapers

TABLE 10-3B
Demand Related Marginal Cost of Distribution
Customer Specific Equipment Methodology

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Year	Lines	Replacement Lines	New Business Lines	Land	Subs	TOTAL	Index	Reflated Additions	Cumul. Demand Portion	Cumulative Non-Coin Peak Load
1976	47.1	18.8	28.3	0.9	13.4	61.0	1.820	77.532	77.532	1078
1977	58.8	24.7	34.1	0.3	-13.0	54.1	1.675	35.845	113.377	1280
1978	58.5	23.4	35.1	0.6	7.3	75.2	1.696	72.928	186.305	2191
1979	68.1	27.2	40.9	0.5	12.3	95.5	1.422	76.361	262.666	2758
1980	73.5	47.4	29.1	0.3	18.8	69.5	1.319	63.576	326.242	2937
1981	94.0	58.3	35.7	2.2	22.2	87.9	1.197	71.940	398.182	3919
1982	90.5	56.1	34.4	0.4	31.1	90.7	1.101	72.556	470.738	3265
1983	76.6	2.0	74.6	0.0	31.6	80.5	1.079	114.590	585.328	3623
1984	91.0	61.0	30.0	3.5	23.0	90.9	1.071	60.512	645.839	5670
1985	138.8	93.0	45.8	4.3	17.7	105.4	1.092	74.038	719.877	4966
1986	153.1	102.6	50.5	11.8	76.4	173.8	1.071	148.548	868.424	4992
1987	158.7	106.3	52.4	2.1	70.5	160.7	1.038	129.750	998.174	5359
1988	161.1	106.3	54.8	0.0	31.5	123.3	1.000	86.300	1984.474	5900
1989	159.6	103.7	55.9	0.5	19.1	113.2	0.961	72.556	1157.030	6393
1990	168.3	111.1	57.2	1.9	26.3	122.0	0.925	78.995	1236.025	6888

Regrression Results: Y = A + B * X

Where Y is cumulative demand-related net additions to plant and x is cumulative additions to distribution level peak demand

A = -222.003
B = 0.203536

Marginal demand costs of distribution = $203.54

(a) from study workpapers
(b) from study workpapers
(c) a - b
(d) from study workpapers
(e) from study workpapers
(f) c + d + e
(g) Handy Whitman Index
(h) f * g
(i) cumulative h
(j) cumulative peak Load additions in study workpapers

The functional subtraction method, in which it is possible to remove all non-demand related costs including the minimum grid, provides the most straightforward calculation. An analyst who employs the engineering method would have to determine individually for each facility which portion of the facility or the investment was incurred to serve customers and what proportion was incurred to serve demand. In both cases, the capacity costs are annualized and adjusted for operation and maintenance costs and for indirect costs. Absent special operation and maintenance studies, it is reasonable to divide O&M costs between customer and demand components on the assumption that they are proportional to the split in the distribution investment. Again, as in the transmission calculation, further adjustments can also be made to account for the losses and the energy component of the distribution cost using the methods outlined above. See Table 10-4.

TABLE 10-4
Demand Related Marginal Cost of Distribution
Minimum Grid vs. Customer Specific Equipment Methodologies
(1988 $)

Description	Minimum Grid $ per KW	Customer Specific Equipment $ per KW
Distribution Investment per KW change in Load (From Tables 10-3A & 10-3B)	159.13	203.54
Annual Cost (*13.08%)	20.82	26.62
Demand Related O&M Expense	5.69	9.17
General Plant Loading	0.80	1.02
Working Capital	0.37	0.47
Total Annual Costs of Distribution/KW	27.67	37.28
Loss Adjustment (1.107%)	30.63	41.27

B. Non-Coincident Peak Demand

To calculate the marginal demand related distribution cost for a particular customer class, the analyst needs to determine, using available load data, the increase in peak demand on the distribution system due to a 1 KW increase in the maximum demand of the class. The peak demand on the distribution system is referred to as the non-coincident peak demand.

Unfortunately, most load research studies have tended to focus on the structure of class demands at the generation and at the customer levels and, therefore, very little is known about the demands on the mid-stream components of the transmission and distribution systems. Consequently, analysts have resorted to various simplifying assumptions in order to determine transmission and distribution system non-coincident peaks. For power systems which depend for the most part on their own resources, it is often assumed that the class composition of the transmission system non-coincident peak demand is identical to the composition of the coincident peak demand at the generation level. This assumption may need to be amended for power systems with important interconnections with other systems.

Unlike the transmission system, however, secondary distribution systems are designed to meet load growth in particular localities. This means, of course, that the non-coincident peak on any portion of the secondary system reflects the combined load of the customers served from it. Because of zoning and land use regulations, load on any particular portion of the secondary system will generally be dominated by either residential or commercial customers. (Industrial customers are more likely to be served directly from the primary distribution system.) This suggests that a close relationship exists between an increase in the maximum demand of the residential or commercial class and the increase in the secondary non-coincident peak (i.e., coincident factor close to unity) for any particular locality. Where customer classes served from the secondary distribution system are mixed this result needs to be amended to take account of the diversity between the classes. As the residential class far out-numbers the commercial class on most systems, the secondary distribution system as a whole will be primarily responsive to residential loads.

Logically, the class demand at the time of peak on the primary distribution system must lie between the previously determined transmission and secondary distribution class demands and it is common to take the statistical average of the two demands.

C. Allocation of Costs to Time Periods

Most analysts assume that the customer related marginal distribution costs do not vary by season or by time of day.

The method adopted to attribute marginal demand related distribution costs depends on the load characteristics of the distribution network. When distribution system components experience maximum demand during the peak costing period identified in the generation analysis, the allocation methods employed for generation (uniform allocation across peak period, probability of excess demand, loss of load probability), and sometimes simply the generation allocation factors themselves, can be used to attribute distribution costs to time periods. As noted above in the discussion on the allocation of transmission costs, if the generation allocators are used it may be necessary to adjust for the effect of the ambient temperature on line capacity and, therefore, on the seasonal allocation of costs. Load research at the distribution substation transformer level has indicated in a number of jurisdictions, however, that different segments of the distribution network peak at different times in the day and year, and are not closely related to the system peak. Those jurisdictions may find it more appropriate to adopt an equal allocation of distribution capacity costs or to allocate costs based on either the proportions of the number of substations that peak during the individual costing periods, or by relating the amount of distribution investment to the timing of the peak demand where the investment was made.

III. CUSTOMER

Marginal customer costs in the functionalization step of a marginal cost of service study are generally identified as those facilities and services that are specific to individual customers. These costs include the costs of the service drops, the costs of meters and metering and the customer accounts expenses. These costs are assumed to vary solely according to the number of customers on the utility's system, and are, therefore, classified 100 percent customer related as well. Jointly used facilities such as line transformers and interconnecting secondary conductors that have been functionalized as distribution costs and that the analyst may have classified as customer related, have been discussed above in the "Distribution" section.

A. Costing Methodologies

Most analysts assume that in current dollars there is little incremental change in the cost of customer related facilities and expenses. Since customer related facilities are added in small increments and exhibit little technological change, the effects of vintaging and technological change, which normally distinguish marginal and embedded costs, are reduced. Thus, while it would be possible to calculate over some planning horizon the change in customer related cost in constant dollars against the expected change in the number of customers, the analyst would not expect the resulting marginal cost to differ significantly from the average embedded cost. Therefore, most marginal cost studies adopt a form of embedded analysis to calculate the total investment cost which is then amortized using an economic carrying charge.

If the minimum grid methodology is used, the customer related investment cost is that calculated in the distribution portion of the study. Otherwise, the cost of meters and service drop investment is analyzed separately by the type of metering installation or by customer load class by determining the characteristics of the service required. While it would be possible to identify separate demand and customer components of meter costs assuming that the more complex metering can be identified with higher levels of demand, all metering costs are usually charged on a per customer basis and, therefore, there is no reason to distinguish between the two components. Annual costs of each type of equipment are calculated by multiplying the installed cost by an annual carrying charge, and adding a factor to reflect operation and maintenance expenses.

Customer accounts (meter reading and billing), service and informational expenses are usually analyzed over a recent historical period, with the expenses converted to current year dollars. The customers in each customer class are weighted based on an embedded study of costs per customer or on discussions with company personnel. The customer expenses are allocated to each load class based on the weighted number of customers. See Tables 10-5A and 10-5B.

B. Allocation of Costs to Time Periods

While a case could be made that there are seasonal variations to such customer accounts as meter reading and customer information, the data is typically not analyzed on a monthly basis and there is no attempt at seasonal differentiation in the cost studies.

Table 10-5A
Customer Related Marginal Costs - Minimum

	Residential		Commercial			Industrial		Agricultural
		GS-1	GS-P	GS2-S	Sub-T	Primary	Sec	
Customer Related Investment Cost	759.00	755.00	2723.00	2416.00	8290.00	8701.00	20262.00	1763.00
Annualized Cost	99.28	98.75	356.17	316.01	1084.33	1138.09	2650.27	230.60
Customer related O&M	17.00	17.00	62.00	55.00	189.00	198.00	462.00	40.00
General Plant Loading	3.82	3.80	13.71	12.17	41.75	43.82	102.04	8.88
Working Capital	1.69	1.68	6.05	5.37	18.43	19.35	45.05	3.92
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	147.79	163.23	479.93	430.55	2219.51	2285.26	4145.36	362.40
Weighted Average	147.79		224.61			3599.08		362.40

Table 10-5B
Customer Related Marginal Costs - Customer Specific

	Residential	GS-1	Commercial GS-2	GS2-S	Sub-T	Industrial Primary	Sec	Agricultural
Customer Related Investment Cost	309.09	476.37	2007.83	5209.66	8473.46	8473.46	14716.85	2861.61
Annualized Cost	40.43	962.31	262.62	681.42	1108.33	1108.33	1924.96	374.30
Customer Related O&M-Same % as MG	6.92	10.73	45.72	118.60	193.18	192.82	335.56	64.93
Customer Install Equipment	0.46	0.47	1.68	1.49	9.43	5.45	12.54	1.09
General Plant Loading	1.56	2.40	10.11	26.23	42.67	42.67	74.11	14.41
Working Capital	0.69	1.06	4.46	11.58	18.84	18.84	32.72	6.36
Customer Account Expenses	26.00	42.00	42.00	42.00	886.00	886.00	886.00	79.00
Total Customer Marginal Cost	76.05	118.97	366.60	881.33	2258.43	2254.11	3265.90	540.09
Weighted Average Class MC	76.05		285.75			2970.31		540.09

Schedule NLP-SR1

CHAPTER 11

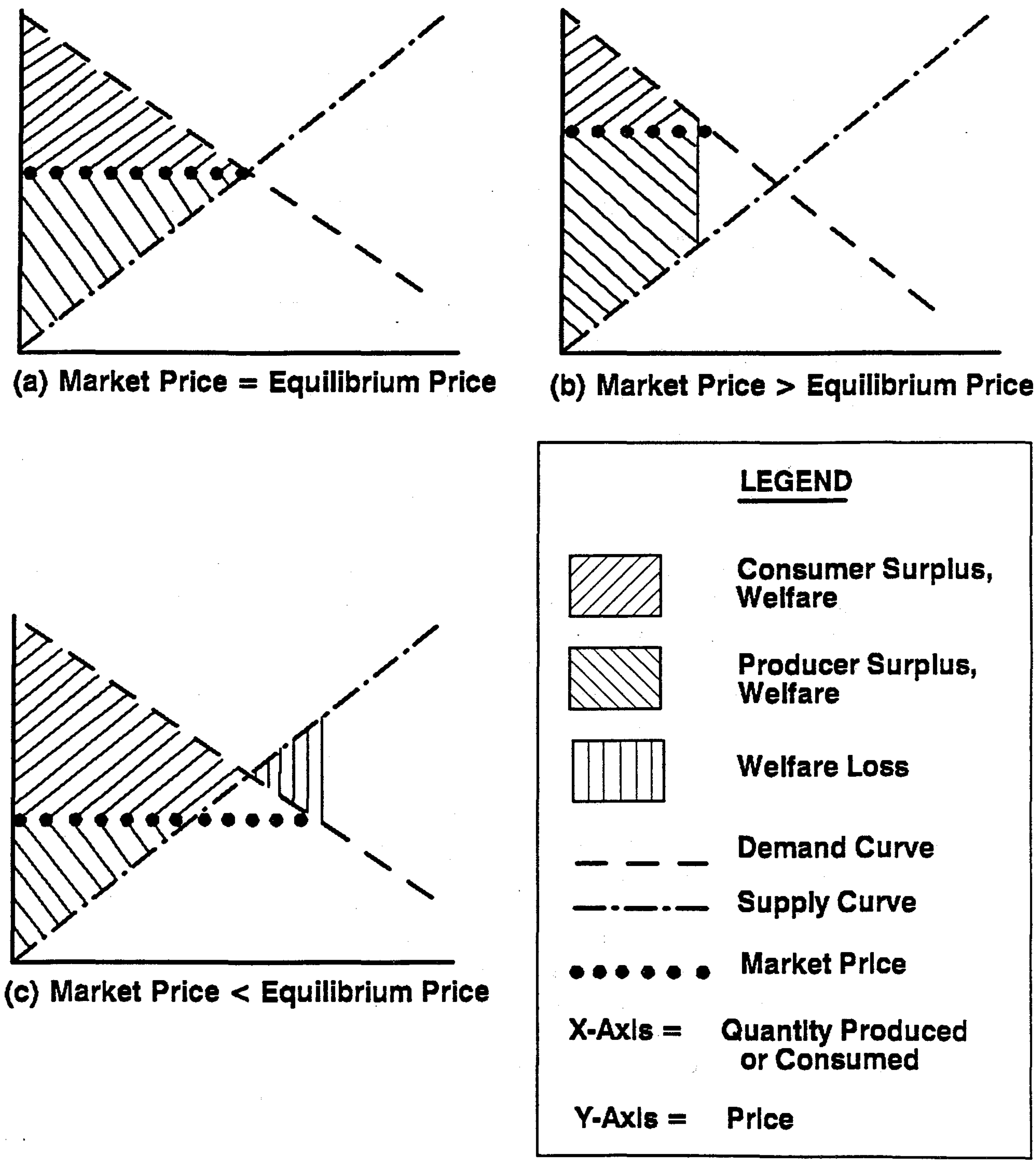
MARGINAL COST REVENUE RECONCILIATION PROCEDURES

The major reason for allocating costs using marginal cost principles is to promote economic efficiency and societal welfare by simulating the pricing structure and resulting resource allocation of a competitive market. Competition drives production and consumption to where customers are willing to pay a price for the last or marginal unit consumed equal to the lowest price producers are willing to accept for their product. This situation occurs where the supply (marginal cost) and demand curves intersect. Since this equilibrium price is charged for all units of production, consumers pay a price lower than they would be willing to pay and producers charge a price higher than they would be willing to charge for all non-marginal units, generating benefits to both called "consumer surplus" and "producer surplus," respectively (Figure 11-1).

The sum of consumer and producer surpluses, which is one measure of societal welfare, is maximized where the supply and demand curves intersect (Figure 11-1A). A price differing from that at the intersection will result in lower production and consumption, reducing the sum of consumer and producer surpluses (Figures 11-1B and 11-1C). Marginal cost pricing will tend to move production and consumption to the equilibrium level where the two curves intersect.

Pricing a utility's output at marginal cost, however, will only, by rare coincidence, recover the ratemaking revenue requirement. Marginal and ratemaking costs vary in time, and often tend to move in opposite directions. For example, when new plant is added, ratemaking costs increase while short-run marginal costs decrease. Conversely, ratemaking costs are low relative to marginal costs when older, largely depreciated plant, continue to provide service. A second cause for disparity arises for companies which have yet to exhaust economies of scale. Because the cost of the next unit will be lower than all previous units for such companies, marginal costs must be necessarily lower than average or ratemaking costs. Finally, the manner of capital amortization will act to produce a systematic difference between annual revenues under marginal cost pricing

Figure 11-1
SOCIETAL WELFARE



and conventional ratemaking treatment. In a competitive market, returns to capital assets are based more on the productive output of the asset than vintage. The simplest model assumes no changes in the supply and demand curve over time, leading to constant output and, therefore, constant real amortization of capital assets, often modeled with a real economic carrying charge. In contrast, ratemaking revenues, often based on original cost less accumulated depreciation, reflect the asset's vintage because such conventions produce real ratemaking revenue streams that start high and decline sharply over the life of the capital asset.

Since marginal and ratemaking costs seldom are equal, an allocation based on marginal cost must normally be modified to produce the revenue requirement. Some economists have argued that rates should directly equal marginal costs, with excess revenues taxed away and deficits made up through government subsidy. But this position has never been adopted by any U.S. jurisdiction. The method is also not perfectly accurate because the change in taxes from this strategy will produce an income effect that will change the consumption of all goods, including utility services.

I. REVENUE RECONCILIATION METHODS

Given the need to modify the allocation based on marginal cost to make it conform to the revenue requirement, the practical objectives have been to find modifications which minimize the distortion to the marginal cost price signal without doing any great injustice to normally held views of fairness and equity. Four major approaches, referred to by different names by different experts, have been proposed:

- Ramsey Pricing (Inverse Elasticity Method).
- Differential Adjustment of Marginal Cost Components.
- Equi-proportional Adjustment of Class Marginal Cost Assignments.
- Lump Sum Transfer Adjustment.

The four methods are somewhat interrelated. The first method produces differential adjustments to overall class cost assignments based on relative demand elasticity, while the second method makes differential adjustments to energy, demand, or customer cost components of the allocation based on their relative elasticity of demand. The third can be seen as a special case of Ramsey Pricing where all classes are assumed to have, from a practical standpoint, nearly the same demand elasticities. The fourth method involves directly charging marginal cost prices, and accomplishing revenue reconciliation with a separate rebate or surcharge on customer bills. In allocating the excess or deficit revenues to determine the rebate or surcharge, variations of the other three methods may be used.

The following sections will evaluate these four alternatives with respect to the criteria of efficiency, equity, rate stability, and administrative feasibility. The first method is generally viewed as the most efficient, but empirical problems render it administratively difficult, and it is clearly discriminatory. The second method is efficient, but it leads to rate instability over time because all the adjustments are often made in one rate component. The third method is viewed by many as most equitable. It normally produces the most stable revenue allocation over time, but some argue it is not efficient. The fourth method is the most efficient if there is no direct relationship between usage and the rebate or surcharge. However, without a linkage to usage, customer rebates and surcharges can be perceived as inequitable.

Table 11-1 develops an allocation based on marginal cost with no reconciliation to the revenue requirement. It shows marginal cost revenues, the revenues that would be collected from each class if all rates and charges were set at marginal cost. The allocation in Table 11-1 is subsequently modified in the following four tables to collect an exact ratemaking revenue requirement of $6,222,100,000. Tables 11-2 and 11-3 use inverse elasticity methods, Table 11-4 uses an adjustment to marginal customer cost revenues, and Table 11-5 uses an equi-proportional adjustment for each class.

The estimates in Table 11-1 are probably best regarded as long-run marginal costs since they encompass all elements of incremental service including demand growth and customer additions with investment cost components for capital equipment. Economists will argue that market prices will be determined by short-run marginal costs, and that these represent the most efficient pricing signals. This may be true given a fixed stock of customer electric equipment. However, given time to modify their electrical appliances, long-run cost signals may, in fact, have comparable efficiency. An allocation based on short-run costs will probably be unstable over time since short-run costs tend to be considerably more volatile than long-run costs.

Use of long-run marginal costs in the allocation offers the advantage of stability in customer bills and also sends a price signal that can guide long-term customer investments into energy using equipment. Short-run marginal costs can still be reflected in the final rate design in tailblock energy rates. This allows marginal usage to be priced directly at short-run marginal cost while still permitting bill stability and some signal to guide long-run customer investments, assuming that customers respond to both their total bill as well as their marginal rate.

TABLE 11-1

CALCULATION OF MARGINAL COST REVENUES
Marginal Energy Costs

Class	Energy Use (GWH)			Marginal Costs (Cents/KWH)			Marginal Cost Revenues
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid Peak	Off Peak	($1000)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]= ([1]*[4]+[2]*[5]+[3]*[6])
Summer Period							
Residential	1454.6	2110.7	3620	4.18	3.00	2.70	221863.2
Commercial	2185.2	2514.1	3430.9	4.17	2.99	2.69	258585.6
Industrial	1478.8	2056.6	3482.4	4.08	2.94	2.64	212734.4
Agricultural	167.9	252.5	496.3	4.18	3.00	2.70	27993.32
Street Lighting	0	26.4	100.3	4.13	2.97	2.67	3462.09
Winter							
Residential	2078.4	2981.7	7414.7	3.68	3.05	2.86	379487.3
Commercial	1832.6	5398.4	6572.9	3.68	3.05	2.85	419418.5
Industrial	2626.4	4205.1	7271	3.57	2.96	2.80	421821.4
Agricultural	119.3	301.8	652.8	3.68	3.05	2.86	32265.22
Street Lighting	49.6	0.2	257.6	3.63	3.01	2.83	9096.58
	Annual Sales By Class			**Annual Average**			
Residential	19660.1			3.058736			601350.6
Commercial	21934.1			3.091096			678004.1
Industrial	21120.3			3.004483			634555.8
Agricultural	1990.6			3.027154			60258.54
Street Lighting	434.1			2.893036			12558.67
Total	65139.2			3.049972			1986727

Marginal cost rates are shown at the level of the system at which the customer takes service. These have been calculated by multiplying marginal costs at the generation level by the appropriate line loss factors to transmission, primary, and secondary distribution levels.

TABLE 11-1 (Continued)

Marginal Demand Costs

Class	Demand (MW)	Marginal Demand Costs ($/KW Year)				Marginal Demand Cost Revenues
	Coincident	Non-Coincident	Generation	Transmission	Distribution	($1000)
	[1]	[2]	[3]	[4]	[5]	[6]= [1]*[3]+[1]*[4]+[2]*[5]
Residential	5,170	5,420	88.32	34.33	41.27	857,803
Commercial	5,735	6,900	87.96	34.19	41.10	984,133
Industrial	3,720	4,332	86.12	33.47	40.24	619,195
Agricultural	420	447	88.32	34.33	41.27	70,016
Street Lighting	6	119	87.36	33.95	40.82	5,606
System average/total	15,052	17,218				2,536,754

Demand Costs are shown for the level at which the customer takes service, reflecting line loss factors.

Generation and transmission demand marginal cost revenues are calculated using LOLP-weighted hourly loads.
The LOLP-weighted loads incorporate not only the group's load during the single hour of the system's coincident peak, but also other high usage hours which impact overall system reliability. LOLP-weighted hourly demands are used to apportion the system's coincident peak load amongst the allocation rate groups.

Distribution marginal cost revenues are based on non-coincident demand, reflecting tge loss of load diversity benefits lower down in the system.

TABLE 11-1 (Continued)

Marginal Customer Costs

Class	Marginal Cost Per Customer ($/customer year)	Number of Customers	Marginal Customer Cost Revenues ($1000)
	[1]	[2]	[3]= [1]*[2]/1000
Residential	76.05	3,209,631	244,092
Commercial	285.75	458,978	131,153
Industrial	2970.31	2,421	7,191
Agricultural	540.09	26.635	14,385
Street Lighting	1723.39	19,974	34,113
System averge/total	115.92	3,717,459	430,935

Customer related access equipment is estimated as the costs of typically sized final line transformers, service drops, and meters (T-S-M). Street Lighting investments, in addition, include poles, brackets, and luminaires.

Investment costs are annualized by a real, or economic carrying charge rate (RECC) which amortizes the investment in a level stream of constant value dollars: equivalent to a nominal value dollar stream rising at the rate of inflation.

TABLE 11-1 (Continued)

Marginal Cost Revenue Summary ($1000)

Class	Energy	Demand	Customer	Total
Residential	601,351	857,803	244,092	1,703.246
Commercial	678,004	984,133	131,153	1,793,290
Industrial	634,556	619,195	7,191	1,260.942
Agricultural	60,259	70,016	14,385	144,660
Street Lighting	12,559	5,606	34,113	52,278
System Total	1,986,728	2,536,754	430,935	4,954,417

A. Inverse Elasticity Method

Ramsey Pricing, often referred to as inverse elasticity pricing, attempts to produce an approximation of the pattern of demand that would exist under direct marginal cost pricing. It does so by distributing system excess or deficit revenues, relative to marginal cost revenues, in an inverse relationship to a customer's elasticity of demand. By selectively loading excess or deficit revenues on customers whose demands are relatively insensitive to price, the overall level and interclass pattern of demand will deviate the least from direct marginal cost pricing. Those users who are most likely to modify their usage of society's scarce resources in response to price will be charged a price closer to the opportunity cost to society of scarce resources (marginal cost). Those consumers who are least likely to respond to price changes are charged prices which deviate the most from marginal costs.

The equational form of the rule is commonly expressed in either of two ways. The exact expression of the Ramsey pricing principle is achieved by setting the difference between the average price (P_i) for an allocation class and its marginal cost (MC_i), relative to its price, inversely proportional to the price elasticity of demand (E_i):

$$\frac{P_i - MC_i}{P_i} = \frac{K_a}{E_i} \quad \text{or,} \quad P_i = \frac{MC_i}{1 - \frac{K_a}{E_i}}$$

K_a is a constant necessary to reconcile the sum of class allocated revenues to the system ratemaking revenue requirement. The equation for K_a is a polynomial expression requiring iterative successive approximations. Table 11-2 provides an example.

To avoid a problem requiring iterative approximation, a Quasi-Ramsey price formula is frequently used. The equation is specified such that the difference between price and marginal cost, relative to marginal cost, is inversely proportional to elasticity:

$$\frac{P_i - MC_i}{MC_i} = \frac{K_b}{E_i} \quad \text{or,} \quad P_i = MC_i\left(\frac{K_b}{E_i} + 1\right)$$

A direct solution can be obtained for the system constant K_b. Table 11-3 gives an example.

The Quasi-Ramsey price equation is an approximation of the theoretically correct specification of the rule. It is simpler to solve than the theoretically correct equation and the level of error introduced by this approximation is allegedly of the same order of magnitude as the errors of measurement inherent in the other parameters such as elasticity estimates. It does not appear, however, that sufficient analysis has been performed to determine whether the level of error is acceptable. Problems in applying the inverse elasticity rule are discussed in greater detail in NARUC's Electric Utility Rate Design Study #69, Appendix A.[1]

Ramsey Pricing can be said to be efficient in that it deviates the least from an allocation of resources that would be produced under pure marginal cost pricing. If it results in higher prices for customers with low elasticities, the prices still reflect the greater value they receive. This is because customers with inelastic demand curves, either because their options are fewer or they have greater need for the service, derive greater consumer surplus. Conversely, if capacity shortages cause marginal costs to exceed average cost, charging customers with more options higher prices will force them to exercise those options; thereby, relieving capacity shortages. Nevertheless, Ramsey Pricing can be considered inequitable since it charges different customers different prices for the same product, based on value of service principles.

There are also a number of practical problems in applying Ramsey Pricing. The data related to elasticities and demand functions needed to apply the method are contestable or, in some jurisdictions, unavailable. Quantitative application of the method requires solving a system of equations, the data for which are not available.[2] Furthermore, elasticities may vary greatly over a small range of demand if closely priced substitutes or alternative sources of supply (cogeneration) are available, creating instability in the allocation over time. Finally, the variance in the demand elasticities between individual customers within a class may exceed the variance in the aggregate class demand elasticities on which the allocation is based. Thus, Ramsey Pricing would not produce the desired pattern of consumption of resources at the individual customer level without charging a different price to each customer based on the customer's elasticity.

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[1]Gordian Associates, Inc., An Evaluation of Reconciliation Procedures for the Design of Marginal Cost-Based Time-of-Use Rates, Electric Rate Design Study #69 (New York, November 7, 1979).

[2] See Ibid., Appendix A.

TABLE 11-2

EXACT RAMSEY PRICE REVENUE ALLOCATION
(Marginal Cost Revenue Allocation By Inverse Elasticity Rule)

Class	Sales (GWH)	Elasticity of Demand (E)	Inverse Elasticity (1/E)	Maringal Cost Revenue ($1000)	Ramsey Price Revenue ($1000)	(Ramsey - Marginal Cost) / Ramsey	Ramsey Price To I nverse Elasticity Ratio	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] = [4] / (1-(Ka/[2]))	[6] = ([5]-[4]/[5])	[7] = [6]/[3]	[8] = [5]/([1]*10)
See Footnote								
Residential	19,660	1.12	0.89	1,703,246	2,145,964	0.20630277	0.2310591	10.92
Commercial	21,934	1.23	0.81	1,793,290	2,208,085	0.18785293	0.2310591	10.07
Industrial	21,120	1.05	0.95	1,260,942	1,616,709	0.22005629	0.2310591	7.65
Agriculatural	1,992	1.05	0.95	144,660	185,475	0.22005629	0.2310591	9.31
Street Lighting	434	1.12	0.89	52,278	65,866	0.20630277	0.2310591	15.17
System avg/total	65,140			4,954,416	6,222,100		Ka= 0.2310591	9.55

Starting with the exact Ramsey Price equation, $(P_i-MC_i)/P_i= Ka/E_i$, prices are first converted to revenues and the equation is simplied to the form; Ramsey Rev. i= MC Rev. i/(Ka/E_i). The constant Ka, which will reconciled marginal costs and the system ratemaking revenue requirement, RR can be estimated by successive approximations to the equation;

$$RR-\sum_{i=1}^{i=n} \{MC\ Rev.i/(1-Ka/E_i)\}=0$$

In the example: 6,222,100-{1,703,246/(1-Ka/1.12)+1,793,290/(1-(Ka/1.23).....+ 52,278/(1-Ka/1.12)}= 0 with Ka= 0.231059.

Note that the Ka factor is equal to the relative difference between Ramsey Price and Marginal Cost Revenues divided by the inverse of the elasticity coefficient (See column [7]). The ratio is the same for all classes idicating that exact Ramsey Pricing has been achieved.

TABLE 11-3

QUASI-RAMSEY PRICE REVENUE ALLOCATION
(Marginal Cost Revenue Allocation By Approximate Inverse Elasticity Rule)

Class	Sales (GWH)	Elasticity of Demand (E)	Inverse Elasticity (1/E)	Marginal Cost Revenue ($1000)	Quasi-Ramsey Price Revenue ($1000)	(Ramsey - Marginal Costs) / Ramsey	Ramsey Price To Inverse Elasticity Ratio	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] Kb * ([4] / [2]) + [4]	[6] [5] - [4]) / [5]	[7]= [6] / [3]	[8]= [5] / ([1] * 10)
Residential	19,660	1.12	0.89	1,703,246	2,144,999	0.20594560	0.230659074	10.91
Commercial	21,934	1.23	0.81	1,793,290	2,216,802	0.19104638	0.234987042	10.11
Industrial	21,120	1.05	0.95	1,260,942	1,609,782	0.21670008	0.227535084	7.62
Agricultural	1,992	1.05	0.95	144,660	184,680	0.21670008	0.227535084	9.27
Street Lighting	434	1.12	0.89	52,278	65,837	0.20594560	0.230659074	15.17
System avg/total	65,140			4,954,416	6,222,100		Kb= 0.290482711	9.55

Starting with the Quasi-Ramsey Price formula, $(P_i-MC_i)/MC_i=Kb/E_i$, prices are converted to revenues , and the equation is rearranged to give the class Ramsey Price Revenue expression; P_i Rev.= Kb*(MC Rev. i/E_i)+MC rev.i.

Summing later expression over the "i" rate classses, a constant Kb can be found which will reconcile the marginal cost and ratemaking revenue requirement, RR, as follows:

$$Kb = (RR - \sum_{i=1}^{i=n} \{MC\ Rev.i\}) / \sum \{MC\ Rev.i/E_i\}$$

In the example, Kb= (6,222, 100-4,954,416)/ ((1,703,246/1.12)+(1,793,290/1.23)....+(52,178/1.12)) = 0.29048

Note that in colum [7] the ratios vary amongst the rate classes, reflecting the fact that the deviations from marginal cost pricing are not exactly proportional to the inverse of the elasticity coefficients.

B. Differential Adjustment of Marginal Cost Components

This method makes differential adjustments to various marginal cost components primarily based on the elasticity of demand with respect to changes in the price of that component. It is generally alleged that the marginal customer cost component has the lowest elasticity. Sometimes, all reconciliation is made in the marginal customer cost component, and this approach has been called the "customer cost giveback" approach when marginal cost exceeds average cost.[3]

Ideally, this method offers the opportunity for the most efficient allocation by differentiating class revenue assignments by not only class elasticity of demand but also by elasticities for the individual components of energy, demand, and customer access. Since no data exist differentiating elasticities by rate component by class, this method only operates in practice by accomplishing reconciliation in what are believed to be the least elastic rate components (e.g., customer costs) without asking whether these elasticities differ by class. As such, the practical application of this method is generally only a very crude approximation of Ramsey Pricing.

In general, this method can be considered inequitable because of the varying size of the customer cost component relative to other marginal cost components for different customers. The customer cost component tends to be larger relative to the other components for small, low-use customers. Thus, small customer rates are increased when marginal costs exceed average costs and decreased when the opposite occurs. In states with lifeline or baseline requirements that set the residential first block rates below cost, this method can result in very high tailblock rates when average cost exceeds marginal cost. The cost allocation can also be very unstable over time with this method. But the method is easier to implement than Ramsey pricing if it is done without explicit elasticity data.

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[3] Gordian Associates, *op. cit.*, pp. 24-26.

Table 11-4 illustrates the method by applying all the reconciliation adjustments to the customer cost component of the allocation. Since it was necessary to increase the size of the customer cost component several times to fill the gap between marginal cost revenues (Table 11-1) and the revenue requirement ($6.22 billion), the impact of this method on smaller customers is significant.

C. Equi-proportional (Percentage) Adjustment of Class Cost Assignments

This method entails increasing or decreasing marginal cost revenues for each class by the same proportion to conform the allocation to the ratemaking revenue requirement. It has been called Equal Percentage of Marginal Cost where a simple multiplier is applied to the allocation to each class to achieve the reconciliation.

The method is arithmetically simple. It is also viewed as highly equitable by those who see equity as relating to the costs a customer imposes on the system at the margin. It is also the most stable over time because it is not sensitive to changes in elasticities, and it is only somewhat sensitive to changes in the sizes of the marginal cost components relative to each other over time.

The method can be criticized as being less efficient than Ramsey Pricing or Differential Component methods which are based on elasticities of customer groups or marginal cost components. This criticism is perhaps less valid if the Equal Percentage method is seen as a special case of Ramsey pricing used in elasticities, and it is only somewhat sensitive to changes in the sizes of the marginal cost components relative to each other over time.when class elasticity data is so poor or intra-class variations in elasticity are so high that applying existing data in the allocation would result in an even more distorted allocation than merely assuming all customer classes have equal elasticities. Whether Ramsey pricing (using differing elasticities) is the proper model for a competitive market is also debatable. Such market differentiation is only successful where sufficient competition does not exist to eliminate price discrimination. Furthermore, the Equal Percentage method may better reflect the long-run tendencies of a private market. When no surpluses or deficits exist, marginal costs will equal average cost and all customers can be charged marginal cost without market differentiation. The EPMC multiplier aims to set marginal cost revenues equal to the revenue requirement (analogous to average cost) without differentiating rates between consumer groups as Ramsey Pricing does or between products (energy, demand, customer access) as the Differential Cost Adjustment method does.

TABLE 11-4

DIFFERENTIAL ADJUSTMENT OF MARGINAL COST COMPONENT ALLOCATION
(Least Elastic Component, Marginal Customer Cost, Adjusted To Meet The Revenue Requirement)

		Marginal Cost Revenues						
Class	Sales (GWH)	Energy ($1000)	Demand ($1000)	Customer ($1000)	Total Marginal Costs ($1000)	Adjusted Customer Costs ($1000)	Final Allocation ($1000)	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5] [2]+[3]+[4]	[6]= [4]*K See Footnotes	[7] [2]+[3]+[6]	[8]= [7] / ([1]*10)
Residenital	19,660	601,351	857,803	244,092	1,703,246	962,141	2,421,295	12.32
Commercial	21,934	678,004	984,133	131,153	1,793,290	516,967	2,179,104	9.93
Industrial	21,120	634,556	619,195	7,191	1,260,942	28,345	1,282,097	6.07
Agricultural	1,992	60,259	70,016	14,385	144,660	56,703	186,977	9.39
Street Lighting	434	12,559	5,606	34,113	52,278	134,463	152,627	35.16
System avg/total	65,140	1,986,728	2,536,754	430,935	4,954,417	1,698,618	6,222,100	9.55

In this allocation the least elastic element of service, marginal customer costs, are proportionally scaled to meet the ratemaking revenue requirements. This sort of allocation can result in extreme instability particularly for rate classes where customer costs constitute a large fraction of the total cost of service. For example, see Street Lighting, where the average rate is more than double that obtained by other allocation methods. The basic reason for rate instability is due to the fact that customer costs are often more highly differentiated amongst the rate classes than either energy or demand costs. Hence, the scaling of marginal customer costs, up or down, to meet the revenue requirement, can produce disappropriate changes in class average rates.

The constant K needed to scale marginal customer to meet the rate making revenue requirement, RR, may be determined as follows:

K= 1+(RR-System Total MC Rev.)/System Marginal Customer Cost Rev.

In the example: K= 1+(6,222,100-4,954,417)/430,935 = 3.9417

Table 11-5 provides an illustration of the Equal Percentage method. The method is less severe than either of the previous two methods in the sense that it produces a lesser degree of rate spread between allocation classes.

D. Lump Sum Transfer Adjustment

The Lump Sum Transfer Adjustment method involves setting all rates to marginal cost and making up the difference between the revenue requirement and marginal cost revenues through a surcharge or rebate added to the bill. The key objective is to design this surcharge or rebate so that it will not influence usage, which would itself interfere with the marginal cost price signal.

Conceivably, there are many ways to distribute a rebate or surcharge. One proposal is to allocate an amount to each class equi-proportional to its marginal cost revenues, but to distribute within the class on an equal dollar per customer basis.[4] This will allow the rebate or surcharge to bear some resemblance to usage, but the resemblance is only approximate because of the per customer allocation within classes. The link between the rebate or surcharge and usage can be further reduced by basing the allocation of the difference between the revenue requirement and marginal cost revenues on relative class marginal cost revenues from a previous period. It is reasonable to surmise that the actual cost allocation resulting from this method, regardless of how it is collected, will be similar to what would result from the Equal Percentage method.

The main disadvantage of customer rebates and surcharges is that customers who are not familiar with the rate structure may react more to the overall bill than to the rates for incremental usage. Another disadvantage is that, as the link between usage and the rebate or surcharge is reduced, the perceived fairness of the method is decreased. Both these shortcomings can be mitigated by taxing or subsidizing the utility. This approach has never been used in any U.S. jurisdiction but is superior to accomplishing the reconciliation with utility rebates or surcharges to its customers. This method of taxing or subsidizing utilities has been used in Europe where utilities are nationalized. Theoretically, it could be implemented in municipal utilities in the U.S. which are owned and operated by local governments.

[4] Gordian Associates, *op. cit.*, pp. 31-33.

TABLE 11-5

EQUI-PROPORTIONAL ADJUSTMENT TO CLASS MARGINAL COSTS

(Equal Percentage of Marginal Cost Allocation)

		Marginal Cost Revenues					
Class	Sales (GWH)	Energy ($1000)	Demand ($1000)	Customer ($1000)	Total Marginal Costs ($1000)	Final Allocation ($1000)	Average Rate cents/KWH
	[1]	[2]	[3]	[4]	[5]= [2]+[3]+[4]	[6]= K*[5]	[7]= [6]/ ([1]*10)
Residential	19,660	601,351	857,803	244,092	1,703,246	2,139,055	10.88
Commercial	21,934	678,004	984,133	131,153	1,793,290	2,252,138	10.27
Industrial	21,120	634,556	619,195	7,191	1,260,942	1,583,579	7.50
Agricultural	1,992	60,259	70,016	14,385	144,660	181,674	9.12
Street Lighting	434	12,559	5,606	34,113	52,278	65,654	15.12
System average/total	65,140	1,986,728	2,536,754	430,935	4,954,417	6,222,100	9.55

The proportional constant K= (System Revenue Requirement/System Marginal Cost Revenues).

In the example: K= (6,222,100/4,741,996)= 1.2558693

II. CONCLUSION

All the described methods for reconciling marginal cost and ratemaking revenue requirements have strengths and weakness. No single method emerges as clearly superior in every respect and in all cases. The best choice will be controlled by the circumstances surrounding the specific utility in question. Table 11-6 provides a numerical comparison of the various reconciliation methods. Note that the Equal Percentage method results in the least degree of rate spread between the allocation classes.

TABLE 11-6

COMPARISON OF MARGINAL COST BASED REVENUE ALLOCATION RESULTS
(Class Average Rates, cents/KWH, to Collect the Ratemaking Revenue Requirement)

	Exact Ramsey Pricing	Quasi-Ramsey Pricing	Differential Adjustment-Customer Costs	Equi-Proportional Method
	[1]	[2]	[3]	[4]
Residential	10.92	10.91	12.32	10.88
Commercial	10.07	10.11	9.93	10.27
Industrial	7.65	7.62	6.07	7.50
Agricultural	9.31	9.27	9.39	9.12
Street Lighting	15.17	15.17	35.16	15.12
System Average	9.55	9.5	9.55	9.55

Where the utility's resource mix is nearly optimal without serious shortages or surpluses, improvements in efficiency may not be critical. The use of long-run marginal costs and the equal percentage of marginal cost revenue allocation method may be preferable in such situations. Short-run marginal costs would be primarily useful in designing specific rate components, particularly tail block energy rates. If equilibrium conditions result in marginal and ratemaking costs being nearly equal, use of a Ramsey Pricing method would produce results similar to an Equal Percentage method.

Conversely, where a utility's resource mix is suboptimal with significant capacity imbalances, the efficiency criteria may outweigh the problems of data acquisition, rate discrimination and sharp rate realignments associated with Ramsey Pricing or related methods using elasticity of demand. Sharp rate realignments to existing customers can be mitigated by allocating costs to existing sales using an Equal Percentage method and by limiting rate discounts or penalties based on demand elasticities only to clearly incremental sales or sales that could be lost to customer self-generation. Capacity surpluses can result in retail rates significantly higher than both the utility's marginal cost and the cost of self-generation, creating a threat of customer bypass. Extending rate discounts to customers or classes with high self-generation potential, even if it requires increasing the rates of more captive customers, can be more beneficial to captive customers than allowing potential self-generators to bypass the utility system, leaving the responsibility for covering fixed costs entirely to the remaining customers.

Though all these methods are second best solutions to direct marginal cost pricing, the system average rate can be brought closer to marginal cost in situations of substantial excess capacity through disallowances. If this is not possible, major rate realignments must be phased-in over several rate periods. Regulatory authorities, which must balance the welfare of the entire ratepayer population against that of significant individual customer groups, are often concerned with "rate shock". Rate shock can be moderated by limiting or capping class revenue assignments to produce changes in the class average rate deemed acceptable. Another method is to weight the system average rate change with the rate change suggested by the economically desired allocation, which will produce a partial approach to the latter.

Schedule NLP-SR1

APPENDIX A

DEVELOPMENT OF LOAD DATA

The allocation of demand-related costs cannot be accomplished without determining, by some means, the demands of the various rate classes and their interrelationships with a utility's total system demand. Since demand-related costs constitute a large portion, if not a majority, of a utility's fixed costs, it is important that the means of determining these demands for a utility yield accurate results. The way a utility often estimates these demands is to conduct periodic research studies of its load.

Load research studies require sampling of customers in those rate or customer classes where it is too expensive to have time-recording meters on all customers. Time-recording meters are installed on the sample of customers selected for each class. The load data collected for the sample of a class is then used to estimate statistically the demands of that class by hour or for designated hours. If the test year of the cost of service study does not coincide with the year (or period) for which the load research was collected, demands for the test period will have to be estimated using load factors estimated from the load study or perhaps by using a model that estimates weather and customer mix changes over time.

This appendix will be divided into four sections consisting of the various phases of a load research study: (1) design of study; (2) collection of data, including installation of meters; (3) estimation of historic loads by class; and (4) use of data, including the projection of class demands for future test years.

Reference will be made throughout this appendix to the term "rate class", which will mean all customers served on a particular rate by that utility. One exception to this is the possible inclusion, for load study purposes, of one or more smaller rates from the standpoint of number of customers or kilowatt-hour use with a larger rate to be considered as a single rate class. Since load studies are essential for the allocation of costs, and it is most meaningful to spread or collect costs by rate classes, the term "rate class" or "class" will be used here accordingly.

Statistical inference is not possible for data collected for judgmental or purposive samples because there is no statistical basis or theory for measuring the precision or reliability of results of judgmental sampling. Since one cannot objectively measure the precision of the demands calculated from judgmental sampling, judgmental sampling should not be used for load research studies. Therefore, this appendix will discuss only probability sampling. In probability sampling, all members of a class have a known, nonzero probability of selection into the sample. The nonzero probability of selection is a consequence of an objective, random procedure of selection.

I. DESIGN OF STUDY

A. Data to be Obtained

The first step in a load study is to determine the load data which must be obtained. The particular methodologies selected for allocating production, transmission and distribution plant will determine the specific load data needed for the cost of service study. In addition to its essential need for cost of service studies, load data is useful in (1) designing rates; (2) evaluating conservation measures; (3) forecasting system peaks; and (4) marketing research studies. Generally, the following data is of interest for cost allocation and design of rates.

1. **Coincident Demand (system peak hours).** This is the demand of a rate class at the time of a specified system peak hour(s).

2. **Class Noncoincident Demand (class peak).** This is the maximum demand of a rate class, regardless of when it occurs.

3. **Customer Noncoincident Maximum Demand (nonratcheted billing demand).** For an individual customer, this is simply the maximum demand during the month for that customer. For the rate class, it is the sum of the individual customer maximum demand regardless of when each customer's maximum demand occurs.

4. **Coincident Factor.** This is the ratio of the coincident demand of a class to either its customer summed noncoincident maximum demands or class noncoincident demand (class peak). It is the percent of class or customer maximum demand used at the time of the system peak. As defined, this can never be greater than unity.

5. **Diversity Factor.** This is the reciprocal of the coincidence factor and is not used as frequently in load study analysis as the coincidence factor. It reflects the extent to which customers or classes do not demand their maximum usage at the same time. As defined, this can never be less than one.

6. **On-peak and Off-peak Kilowatt-Hours.** These are defined as the kilowatt-hours of energy consumed by each class during the on-peak and off-peak periods. These energy values are necessary to allocate energy-related costs in a time-of-use cost of service study and to design time-of-use rates utilizing on-peak and off-peak energy prices.

7. **Load Factor.** This is the ratio of the average demand over a designated time period to the maximum demand occurring in that period. This term can refer to a customer, rate class or the total system. It is a measure of the energy consumed compared to the energy that would have been consumed if the group or customer had used power at its maximum rate established during the designated time period.

B. Selection of Design Precision

Precision expresses how closely the estimate from the sample is to the results that would have been obtained if measurements had been taken on all customers in the class. In order to assure perfect precision for each class demand determined in a load study, it would be necessary to meter individually every customer in every class. In spite of seeming far-fetched, metering every customer may be a desirable method for a class where the customers are large in size, limited in number and individually very different or highly variable. It is frequently practical, for example, to meter every customer over 800-1000 KW in maximum demand. Where large numbers of customers and smaller loads are involved, it becomes necessary to select a sample group of customers for each rate class to be studied.

Precision is the inverse of sampling error. Suppose you decide to select a sample of 275 customers from the residential class using a table of random numbers. The random numbers you use, and hence the customers you select, and the estimate you obtain will all vary with each application of the procedure. The variation this introduces into your sample-based estimate is called the sampling error of your estimate. The smaller the sampling error of your estimate, the closer the estimate is likely to be to the result that would have been obtained if measurements had been taken on the entire rate class. The size of the sampling error varies proportionately with the standard deviation of the population and inversely with the size of the sample. (The standard deviation is a measure of the variation in the population measurements on the variable under study.) Figure A-1 shows the relationships of the distribution of the customer demands (entire population) and the distribution of sample estimators of class demands.

Sampling error can be measured in standard errors. For example, if a simple random sample of 275 residential customers was taken from a population with a standard deviation of 2.23 kilowatts (KW), then the standard error of the per customer demand would be $2.23 \div \sqrt{275} = .13$. We could then say that approximately 68% of our estimates would be within one standard error, or .13 of the per customer demand of the entire class, and about 95% of our estimates would be within two standard errors.

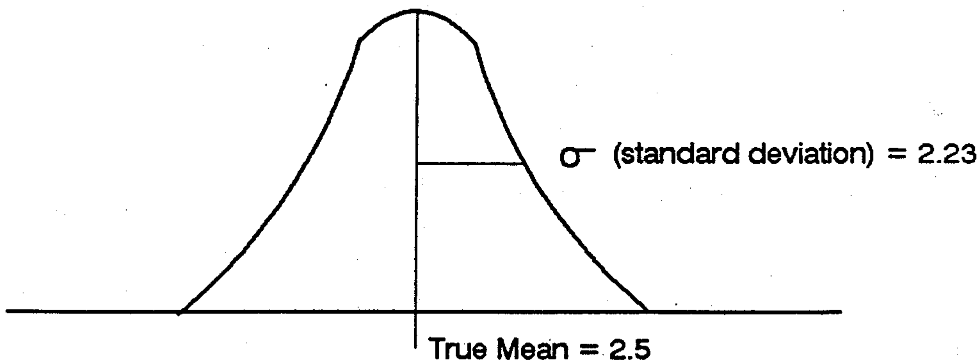
A <u>confidence interval</u> around an estimate is an interval which is designed to contain the class measured demand a specified percentage of the time. For example, an interval of two standard errors on each side of the estimated demand is approximately a 95% confidence interval. This means that if we hypothetically repeated our sampling procedure with new customers each time, about 95% of these calculated intervals around our estimates would enclose the actual class per customer demand. Thus, if our estimated demand were 2.96 KW per residential customer, we would be 95% confident that the interval 2.70 to 3.22 for our residential sample of 275 customers contains the actual class demand per customer. (Confidence interval = $\bar{x} \pm t_p$ (SE $(\bar{x})$; where t_p is a normal deviate which is set at the level of confidence one wants to use. This example is using 95% confidence or $t_p \simeq 2$. Therefore, the confidence interval is $2.96 \pm 2 \times .13$.)

The above confidence interval can be interpreted that our estimates are within ±.26 KW of the true per customer demand for 95% of all possible samples. This .26 KW might be satisfactory precision if the true demand were 2 KW but not if it were 1 KW. In the former case, the <u>relative precision</u> would be $\pm 100 \times (.26 \div 2)$ or ± 13%; in the latter case 100 $(.26 \div 1)$ or ± 26%. (Relative precision = 100 [2 x SE $(\bar{x})$/true per customer demand].) Relative precision expresses sampling error relative to the magnitude of the quantity being estimated. Load researchers generally prefer to choose their sample size on a specified relative precision rather than absolute precision because one relative precision level can be used for classes with very different demands. (Load researchers tend to use the terms accuracy or relative accuracy interchangeably when referring to relative precision of the sample design). However, accuracy refers to nonsampling errors in addition to the sampling errors that we have been discussing.) Sampling error can be reduced to zero by measuring all members of a class, but there can still be nonsampling errors such as meter malfunction, damage to meters, lost tapes and errors in tape translations. For example, if all the meters for a 100% time-recorded class measured .5 KW low, the relative precision of the mean demand estimate would be zero percent error but the accuracy would be minus .5. If the true demand were 2, the relative accuracy would be 100 [(1.5-2)/2] or -25%.

Many commissions require samples to be designed to yield estimates of peak hour demands with a relative precision of plus or minus 10% at a 90% confidence level. This is the standard established by the Federal Energy Regulatory Commission in its implementation of the Public Utility Regulatory Policies Act of 1978.

FIGURE A-1

DISTRIBUTION OF CUSTOMER DEMANDS AND AN ESTIMATOR OF CLASS DEMAND



Population of all demand measurements for the hour of interest.

Sample 1 $\bar{x}$ = 2.3

Sample 2 $\bar{x}$ = 2.7

Sample 3 $\bar{x}$ = 2.6

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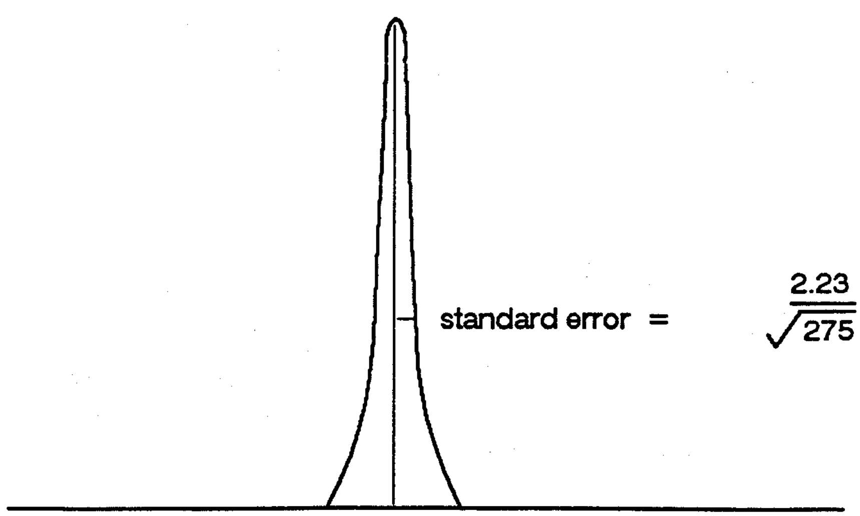

Sampling distribution of $\bar{X}$'s.

C. Design of Sample

The precision of the demands estimated from a sample depends not only on the sample size, but also on the methods used to select the sample (i.e., the sample design) and the statistical procedure used to estimate demands. The primary aim of sample design is to choose the sample design with the smallest error. Two methods of random or probability sampling are used widely to select samples of rate classes: (1) simple random design; and (2) stratified sampling design.

In simple random sampling *n* (equal to the desired sample size) random numbers are taken from a table of random numbers with equal probability. These *n* selected random numbers then identify the customers (or premises) on the frame (numbered listing of all customers in the rate class) whose listing number corresponds to the selected random numbers. These identified customers constitute the selected sample. In simple random sampling each combination of *n* elements has the same chance of being selected into the sample as every other combination.

In a stratified sampling design the rate class is divided into distinct subgroups, called strata, on the basis of kilowatt-hour use or maximum demand. Within each stratum, a separate sample is selected using either simple random sampling or systematic random sampling,[1] most often the latter method. The primary reason for using stratification is to decrease the sampling error and thus increase the precision of the estimate. The use of stratification thus reduces the sample size needed for a specified level of relative precision. The increase or reduction in sample size for a set level of precision will depend on (1) how well the selected strata breakpoints decrease variability of demand within strata relative to the entire class; and (2) the allocation of the overall sample points to individual strata. Another reason for stratification might be to establish subgroups or domains which are of special interest. For example, customers in a metropolitan area may have special interest due to a proposed conservation of marketing program.

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[1] Systematic Random Sampling is an alternative to simple random sampling where by every Kth unit after a random start is selected. This method of probability sampling is commonly used in selecting customers for load studies due to its adaptability to computer selection from the company's billing records. Furthermore, systematic sampling yields a proportionate sample with respect to any ordering in the population. For example, if customers are listed by geographic region, a systematic sample will yield the same proportion of sample customers from each region. However, if the listing of customers reflects a trend or pattern in kilowatt-hour consumption or billing demand, the listing should be shuffled in some manner or the application of systematic sampling modified. (Statistics textbooks will discuss suggested modifications.) Systematic sampling is often used in conjunction with stratified sampling.

Since stratification will almost always be used in selecting samples of rate classes for load studies, the remainder of this appendix will discuss the development of the design of a stratified sample.

1. Analysis of Old Load Data and Customer Information on the Books and Records

Since the purpose of stratification is to reduce the sampling error by making the strata as homogeneous as possible on the particular hourly demands to be used in the cost study to allocate production plant, load data from past studies should be analyzed by class to identify all possible stratification variables. The variables under consideration for the stratification variable must have measurements in the billing or accounting records for every customer in that class. Correlations should be run for a number of variables, such as average monthly energy for twelve months, winter months, summer months, a combination of winter summer months and billing demand.

2. Selection of Stratification Variable

The correlation analysis will identify those variables which are most highly correlated with the demands to be estimated. The following steps are usually employed in the selection of the stratification variable:

- Choose possible stratification variable (from those variables which have higher correlations and have measurement values for most customers)
- Select tentative strata breakpoints
- Make a rough sample size calculation
- Allocate sample points to strata using Neyman allocation
- Check sample size calculation
- Try another design

In calculating the required sample size for a stratified sample, the standard deviation of the demand to be estimated must be used. Often the standard deviation of the variable of stratification is used erroneously. This will lead to sample size estimates that may be too small by an order of magnitude. Since the standard deviation of these demands for the entire rate class is unknown, an estimate from past load research for the class should be used. If no prior load research data is available, an estimate based on load research from a neighboring or similar utility should be used. After calculating the sample size for the possible stratification variables, determine which variable(s) requires the smallest number of sample points for at least the summer peak and winter peak hours.

In two-dimensional designs, each customer has two numbers assigned to him for stratification purposes. Two-dimensional designs are recommended for rate classes with a seasonal pattern of energy and when estimated demands in more than one peak hour are important (i.e., peak winter and peak summer demands are both important). This is because the two-dimensional design is most likely to group together premises of similar load pattern rather than premises similar on a single design hour. Thus, the design can be expected to yield more precise estimates for various peak hours for a given sample size or reduce the sample size required for a given level of precision. A commonly used two-dimensional design for residential and small general service samples is winter month(s) consumption (high and low) and summer month(s) consumption (high and low).

A small but growing number of load researchers are advocating the use of model-based sampling plans to determine the best stratification structure and overall sample size. A model-based sampling plan as now advocated generally uses more strata than traditional methods and allocates equal sample points to each strata. While this approach is somewhat more complicated than traditional methods, one researcher has found a five to six percent saving in required sample size over more conventional methods now in use.

3. Selection of Strata Breakpoints

After determining the stratification variable(s), the dimension of the plan, and the number of strata to be employed, a decision must be made on how to "cut" the stratification variable(s) to form strata. In the past, most load researchers have used the Dalenius-Hodges procedure [1951, 1957] to determine costs which in theory minimize the variance (yield the most precise estimate of demands) when used in conjunction with the Neyman procedure for allocating the number of sample points to strata.

There are several problems associated with the use of this procedure. First, it assumes that a mean per unit estimator is employed in the estimation process while almost all load researchers use the ratio estimator. Second, it involves unrealistic assumptions regarding the knowledge and form of the distribution of the demands to be estimated. Third, the procedure does not produce near optimal breakpoints when, as is generally true, the within-strata correlations are made. Thus, the Dalenius-Hodges technique should be considered only a rough guide in developing stratum cuts.

When developing the stratification strategy for a rate class with a small number of very large customers, a considerable reduction in standard error may be achieved by metering all these very large customers. This is because there is no contribution to the sampling error from any stratum that is 100% metered.

4. Determination of Sample Size

The size of sample required to achieve a specified precision with a specified level of confidence for a particular sample design is calculated using statistical formulas. The statistical formulas to calculate that sample size depend on the form of the estimator (i.e., ratio, mean per unit, or regression) since each estimator calculates variances or standard deviations differently. The sample size calculated will not assure that the specified level of accuracy will in fact be attained; it is a suggested guide. As mentioned previously, in calculating the required sample size, the estimate of standard deviation for the demand allocator in the cost of service study (i.e., the variable of interest) must be used, not the standard deviation of the stratification variable. If more than one hour is of interest, the required sample size should be calculated for various hours of interest from different seasons and the largest indicated sample size should be used. Since with many meter and recorder technologies there will often be missing data, the required sample size that has been calculated should be inflated by the usual percentage of missing data so that the expected number of good measurements will approximately equate to the required number of sample measurements. If there is a pattern to meter failure which is related to demand, bias (loss of accuracy) will result.

The question arises as to whether the sample size should also be inflated to account for customer refusals and sites where a load research meter cannot be installed. It is extremely important to develop field procedures which will keep non-response as small as possible because every non-response is a contributor to bias. There are generally two approaches to selecting alternate sample units for customers who refuse or for whom the meter cannot be installed. The first approach is to increase the calculated sample size to compensate for the expected loss of prime sample points and the second is to use a model to select alternates for each prime. The first method only compensates for the loss of precision due to a reduced sample size but does not address the bias caused by failing to measure certain types of customers. In the latter approach, a list of candidates located on the same or adjoining meter reader routes and having similar usage patterns is sometimes developed for each customer that cannot be used. From the list of suitable candidates for each sample prime customer lost, an alternate is selected randomly. This approach does not, however, totally eliminate the bias caused by non-response.

In stratified designs the sample points are generally allocated to strata where most of the variability exists. This method of allocation (sometimes called optimal allocation) is used to increase the precision of the sample or minimize the cost for a fixed level of precision. Generally, load researchers employ a form of optimal allocation called Neyman allocation, which maximizes the precision of the sample. A sample allocated in proportion to the number of customers is essentially equal to a simple random sample. The preferred minimum number of observations per stratum is approximately thirty so that the normal distribution assumption involved in the statistical estimation procedure can be expected to be met approximately. If domain analysis will be done with the strata, the minimum sample size per stratum should be increased.

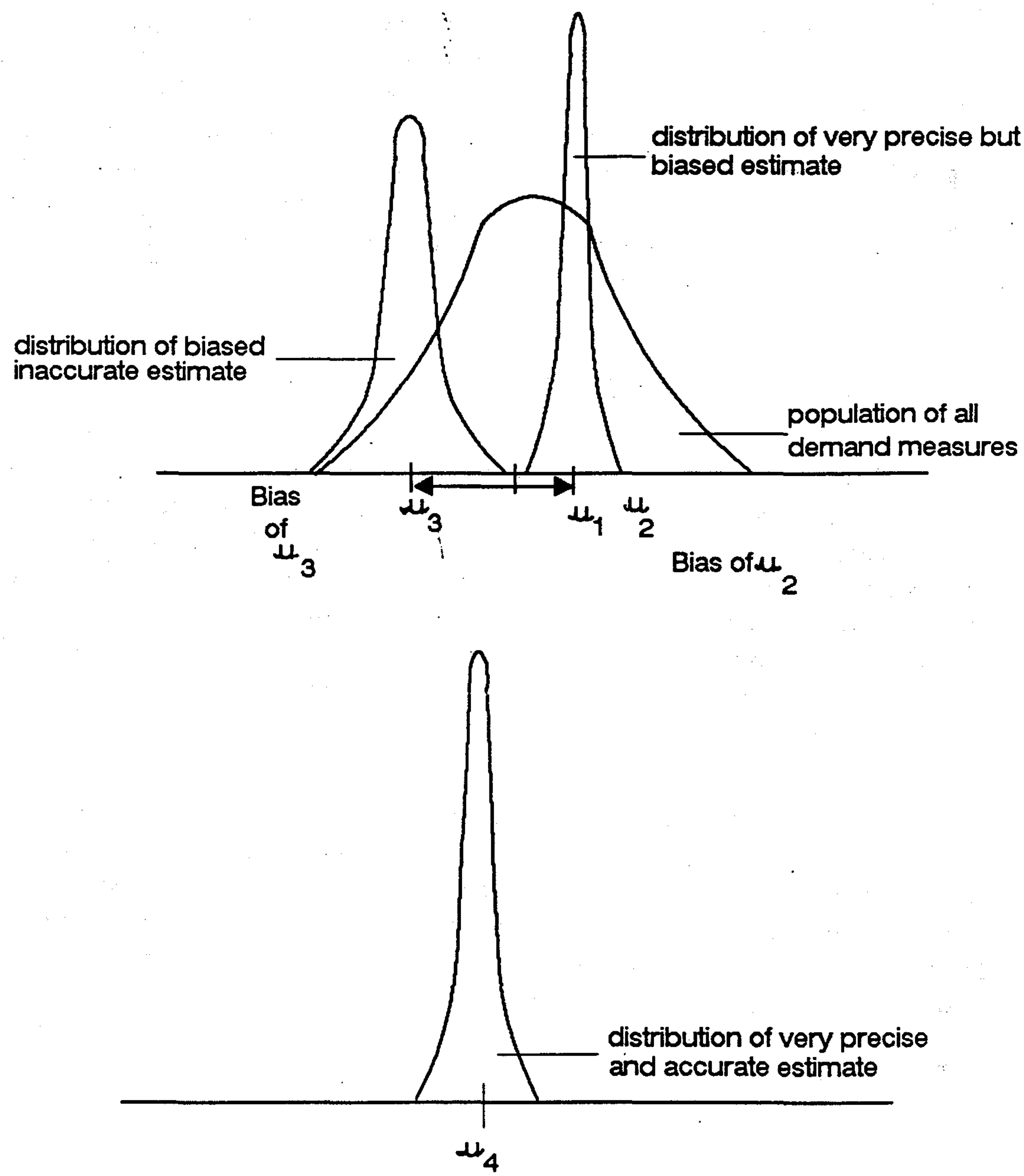
D. Form of Estimator

Prior to 1979, the mean per unit technique was used almost exclusively to estimate class demands from sample results. Since 1979 sampling statisticians familiar with the characteristics of load data and the problems of measuring it have developed applications of statistical theory to the estimation of demands at single hours and a combination of a number of hours. Due to the increased concern about the quality of load data collected through studies and the concern of reducing sampling cost, these developments were disseminated quite widely and many utilities started using the ratio and regression estimators. Recently, much research has been done demonstrating that the ratio estimator is better than the mean per unit estimator and many companies have changed to the ratio statistic.

Ratio and regression estimation use auxiliary data on the billing records for sample customers and the entire rate class to increase the precision of the estimate. When the auxiliary data is billed KWH, the estimation process resembles an application of estimating the load factor rather than the demand itself. In general, the higher the correlation between the auxiliary variable and the demand to be estimated, the greater the increase in precision. Ratio expansion uses energy in the statistical expansion from sample to rate class while mean per unit estimation employs number of customers. While the ratio estimator is technically biased, the degree of bias is extremely small for samples of even moderate size. (In statistical theory, bias refers to the difference between the expected value of the estimate and the true value being estimated.) The form of statistical estimation does not have to be the same in all rate classes. Figure A-2 is a comparison of the distribution of the population demand measures and the distributions of various estimators and shows the bias of these various estimators.

FIGURE A-2

DISTRIBUTION OF CUSTOMER DEMANDS AND OF THREE ESTIMATORS OF CLASS DEMAND



μ_1 = mean of the population of demand measures

μ_2 = mean of precise but biased estimator of μ_1

μ_3 = mean of biased and imprecise estimator of μ_1

μ_4 = mean of precise, unbiased (if $\mu_4 = \mu_1$) estimator of μ_1

E. Selection of the Sample

The sample is selected from a frame or non-duplicative listing of all members (possible sampling units) of the rate class. Unfortunately, in utility research the frame is changing constantly. The dynamic nature of the frame is a concern because the frame from which we sample and consequently collect data is not the same frame about which we will make inferences. The magnitude of this problem can be reduced somewhat by using meter location (address) for the sampling unit as opposed to the customer's name. Since the frame used for sampling will not be representative of the rate class after a period of time due to new customers entering and old customers leaving, new samples should be selected every one or two years or some method should be developed to deal with entries and exits.

F. Selection of the Equipment

The implementation of a load study involves the using of metering, recording, and translation equipment. Currently, rotating disc and solid state meters are available; both of these types of meters may be modified to transmit pulses to a storage device such as a recorder. There are two types of recorders in general use: magnetic tape and solid state. In the magnetic tape recorder the pulses are recorded on a tape which is replaced monthly; a translation machine in a central office converts the data into a form readable by a computer. In addition, the translator checks the data for errors, inconsistencies, and outages or malfunctioning of the recorder.

In the solid state recorder the pulses transmitted by the meter are stored in a memory system which retains the latest thirty or more days of data. The data stored in the solid state recorder can be retrieved by the utility through a telephone line, a power line carrier system or a portable reader which is transported to the meter site to copy the data from the memory of the solid state recorder into its memory. The data which has been retrieved by one of the three methods will also be put through a translator. Since solid state recorders can be used with rotating disc meters, a number of metering and recording equipment options are available.

II. DATA COLLECTION

The success of a load study will require good organization and sufficient training of the field personnel to minimize non-response bias, equipment failure and other measurement problems.

A. Installation of Recorders

To reduce the potential bias from non-response, the importance of installing a recorder on each selected premise should be communicated to the employees installing the meters. Studies have shown that there is a difference, often significant, between the people who refuse and those who participate. Written procedures should be developed to deal with problems, such as different meter installations and customer refusals, and the likely impact of these problems. The employees installing recorders should have to explain in detail why they can't use the selected customer. The alternate should be provided only after review determines that the original selection cannot be used. Customers should not be offered a choice regarding participation; participation should be assumed except in extreme cases. A brochure on why load research is needed with load curves illustrating how the data is used is helpful for developing good customer relations and very low refusal rates.

B. Duration of Study

Data should be collected for at least twelve consecutive months to provide the data required by cost studies in today's ratemaking and costing environment. Also, the data should be collected during the same time period for all rate classes. Because the rate class population is constantly changing, meters should be reset on a new sample of customers every one or two years or some method (such as a "birthing" strata) should be used to account for customers entering or leaving the population. Note, account number changes usually do not mean the premise left the population.

C. Demographic Data

It is often important to obtain demographic and appliance saturation data on the load research sample to enhance the use of the load data for many other applications.

III. ESTIMATION OF LOADS

In this phase of the study computer programs are used to estimate statistically the demands of interest for each rate class sampled. Even though a specific estimator (i.e., mean per unit or ratio) was used during the design phase, this earlier decision does not preclude the use of other estimators in the estimation phase. One may use any estimator provided one does not switch to another estimator after the value is calculated. Sound judgment should be used in the selection of the estimator. The particular formulas used in the estimation process must reflect the design of the sample and whether the estimate is for one hour or a combination of a number of hours. Confidence intervals and the relative precision should be calculated for a specified level of confidence.

IV. USE OF DATA

A. Historic Test Year Coincident with Load Study

Coincident and class noncoincident demands for sampled rate classes would have been estimated statistically for all hours of interest for the cost study in the load estimation phase. In addition, demands should be calculated for all 100% time-recorded classes and the lighting classes. The sum of the coincident demands for all classes for any hour adjusted for losses will not equal the demand the utility generated in that hour. This is because of sampling and nonsampling errors.

When the historic test year is coincident with the year the load data was collected, the cost analyst can use the demands as estimated and calculated but usually an adjustment is made to the demands so that they sum to the actual demand of the utility in that hour. Sampling statisticians prefer that no adjustment be made because of the uncertainty as to whether the adjusted demands by class represent more accurately the class's proportion of the total demand than the statistically estimated demands. Some cost analysts have adjusted the estimated demands proportionately of only those classes that are not 100% time-recorded. This procedure, however, ignores the size of the sampling error of the various estimates and the measurement errors present in 100% time-recorded classes.

B. Projected Test Year or Historic Test Year Not Coincident with the Load Study

When the test year is not coincident with a time period when load research data was collected, the most recent load data must be used to develop projected demands for the test year. The preferred method for projecting coincident demands is to calculate monthly ratios of each class's estimated or calculated coincident demand to its actual KWH sales from the load data. These ratios are then applied to the class's projected test period KWH sales to derive the projected monthly coincident demands.

Similarly, it is recommended that class annual noncoincident demand should be derived by applying the annual class load factor calculated from the most recent load study to the projected annual KWH sales. The use of an annual load factor in contrast to a monthly load factor in the derivation of the class noncoincident class peak demand may, however, result in a larger deviation between the historic and projected coincidence factors. Thus, it is advisable to check the relationship of the projected class noncoincident demands and the projected coincident demands for the same month to that for the same demands estimated in the most recent load studies. The cost analyst may want to explore whether the use of other load relationships will yield projected noncoincident demands whose coincidence with system peak in the same month is more similar. If indicated, different load relationships can be used for different classes.

An example of data collected in a load study is shown in Table A-1.

TABLE A-1
LOAD STUDY DEMAND DATA[1]

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
								Load Factor	
Rate Class	Average Number of Customers	MWH (Output to Line)	Average Demand MW (2) ÷ 8784[2]	Coincident Demand MW Winter	Coincident Demand MW Summer	Class Noncoincid. Demand (MW)	Coincidence Factor [4] ÷ [6]	Coincident Demand [3] ÷ [4]	Non-coincid. Demand [Class] [3] ÷ [6]
Residential	328,480	4,234,145	482	1208	938	1208	1.00	39.9%	39.9%
General Service Non Demand	37,975	642,751	73	119	149	166	.72	61.3	44.0
General Service Demand	5,517	2,368,914	270	338	399	469	.72	80.0	57.6
General Service Large Demand	121	2,696,647	307	322	357	382	.84	95.3	80.4
Street and Outdoor Lighting	142	103,928	12	3	0	22	.14	400.0	54.5
Total Company	372,235	10,046,386	1144	1990	1843			57.5	

[1] At generation level

[2] 8784 hours in a leap year

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company, d/b/a	)	**File No. ER-2014-0258**
Ameren Missouri's Tariff to Increase Its	)	Tariff No. YE-2015-0003
Revenues for Electric Service	)	

REPORT AND ORDER

Issue Date: April 29, 2015

Effective Date: May 12, 2015

BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF MISSOURI

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** Tariff No. YE-2015-0003

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For United for Missouri, Inc.

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For Wal-Mart Stores East, L.P. and Sam's East, Inc.

CHIEF REGULATORY LAW JUDGE: **Morris L. Woodruff**

REPORT AND ORDER

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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.

Summary

This order allows Ameren Missouri to increase the revenue it may collect from its Missouri customers by approximately $108 million, based on the data contained in the Revised True-up Reconciliation filed by the Missouri Public Service Commission Staff on March 28, 2015.[1] Approximately $103 million of that increase is related to Ameren Missouri's increased net fuel costs and would otherwise be recovered by the company through its fuel adjustment clause.

Procedural History

On July 3, 2014, Union Electric Company, d/b/a Ameren Missouri filed a tariff designed to implement a general rate increase for electric service. The tariff would have increased Ameren Missouri's annual electric revenues by approximately $264 million. The tariff revisions carried an effective date of August 2.

By order issued on July 11, the Commission suspended Ameren Missouri's general rate increase tariff until May 30, 2015, the maximum amount of time allowed by the controlling statute.[2] In the same order, the Commission directed that notice of Ameren Missouri's tariff filing be provided to interested parties and the public. The Commission also established July 31 as the deadline for submission of applications to intervene. The following parties filed applications and were allowed to intervene: The International Brotherhood of Electrical Workers Local 1439; The Missouri Industrial Energy Consumers (MIEC);[3] The Midwest Energy Consumers Group (MECG);[4] The Missouri Department of

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[1] This number is only an estimate of the overall impact of the decisions described later in this report and order. This estimate does not in any way control or modify those decisions.

[2] Section 393.150, RSMo 2000.

[3] The members of MIEC are as follows: Anheuser-Busch Companies, Inc.; Ardagh Glass;

Economic Development – Division of Energy; The Consumers Council of Missouri; The Missouri Retailers Association; Sierra Club; The City of O'Fallon and the City of Ballwin; Earth Island Institute d/b/a Renew Missouri; the Natural Resources Defense Council; United for Missouri, Inc.; Wal-Mart Stores East, L.P. and Sam's East, Inc.; and United Steelworkers Union. On August 20, the Commission established the test year for this case as the 12-month period ending March 31, 2014, trued-up as of December 31, 2014. In its August 20 order, the Commission also established a procedural schedule leading to an evidentiary hearing.

In January 2015, the Commission conducted twelve local public hearings at various sites around Ameren Missouri's service area. At those hearings, the Commission heard comments from Ameren Missouri's customers and the public regarding Ameren Missouri's request for a rate increase.

In compliance with the established procedural schedule, the parties prefiled direct, rebuttal, and surrebuttal testimony. The evidentiary hearing began on February 23 and continued through March 12. The parties indicated they had no contested true-up issues and the Commission cancelled the scheduled true-up hearing. The parties filed post-hearing briefs on March 31, with reply briefs following on April 10.

The Partial Stipulations and Agreements

During the course of the evidentiary hearing, various parties filed nine non-unanimous partial stipulations and agreements resolving issues that would otherwise have

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BioKyowa, Inc.; The Boeing Company; Doe Run; Enbridge Energy; General Motors Corporation; GKN Aerospace; Hussmann Corporation; JW Aluminum; Mallinckrodt; Monsanto; Nestlé Purina PetCare; Noranda Aluminum; and SunEdison Semiconductors.

[4] The members of MECG are Continental Cement Company, LLC; Buzzi Unicem USA; Missouri Ethanol LLC, d/b/a POET Biorefining – Laddonia; Cargill; Tyson Foods; Explorer Pipeline Company, Maritz Holdings, Inc.; and Wal-Mart Stores, Inc. Wal-Mart subsequently was granted intervention on its own behalf.

been the subject of testimony at the hearing. No party opposed seven of those partial stipulations and agreements. As permitted by its regulations, the Commission treated the unopposed partial stipulations and agreements as unanimous.[5] After considering the stipulations and agreements, the Commission approved them as a reasonable resolution of the issues addressed in those agreements. The issues resolved in those stipulations and agreements will not be further addressed in this report and order, except as they may relate to any unresolved issues.

The other two non-unanimous stipulations and agreements were objected to by one or more parties. As provided in the Commission's rules, the Commission will treat those stipulations and agreements as merely a position of the signatory parties to which no party is bound.[6] The issues that were the subject of those stipulations and agreements will be determined in this report and order.

Pending Motion

On April 7, the Department of Economic Development (DED) filed an *amicus curiae* brief, accompanied by a petition seeking leave to file the brief. DED is not a party to this case, although the Division of Energy within the Department is a party and filed its own brief. On April 10, two parties, MECG and United for Missouri, filed pleadings opposing DED's petition.

The filing of *amicus* briefs at the Commission is governed by Commission Rule 4 CSR 240-2.075(11), which, among other things, requires that the *amicus* brief be filed no later than the initial briefs of the parties. The initial briefs were filed in this case on March 31. DED delayed filing its amicus brief until April 7; only three days before reply briefs were

[5] Commission Rule 4 CSR 240-2.115(C).

[6] Commission Rule 4 CSR 240-2.115(2)(D).

filed, severely limiting the other parties' opportunity to respond to the *amicus* brief. DED's motion for leave to file *amicus* brief does not comply with the Commission's rule and will be denied.

Admission of True-Up Testimony

A true-up hearing to deal with issues arising from the true-up of Ameren Missouri's costs as of the end of the true-up period on December 31, 2014, was scheduled for March 25. Laura Moore filed Revised True-Up Direct testimony on behalf of Ameren Missouri, Matthew Barnes filed Second Corrected True-Up Direct testimony on behalf of Staff, and Ted Robertson filed True-Up Direct testimony on behalf of Public Counsel.

No party asked to cross-examine any witness, and the true-up hearing was canceled by order issued on March 24. The true-up testimony is assigned the following exhibit numbers and is admitted into evidence.

Moore Revised True-Up Direct	Exhibit 74
Barnes Second Corrected True-Up Direct	Exhibit 247
Robertson True-Up Direct	Exhibit 413

Overview

Ameren Missouri is an investor-owned integrated electric utility providing retail electric service to large portions of Missouri, including the St. Louis Metropolitan area. Ameren Missouri has approximately 1.2 million retail electric customers in Missouri, more than 1 million of whom are residential customers.[7] Ameren Missouri also operates a natural gas utility in Missouri, but the rates it charges for natural gas are not at issue in this case.

[7] Moehn Direct, Ex. 28, Page 4, Lines 5-6.

Ameren Missouri began the rate case process when it filed its tariff on July 3, 2014. In doing so, Ameren Missouri asserted it was entitled to increase its retail rates by approximately $264 million per year, an increase of approximately 9.7 percent.[8] Ameren Missouri claimed a rate increase was necessary due to (a) increases in net fuel costs, largely driven by decreases in off-system sales due to lower power prices; (b) significant investments in infrastructure; (c) increases in income taxes and other taxes; (d) amortizations of solar rebate payments; and (e) changes in depreciation rates to reflect the retirement of the Meramec Energy Center by 2022.[9] The company attributed $103 million of that increase to the rebasing of fuel costs that would otherwise be passed through to customers by operation of the company's existing fuel adjustment clause.[10]

Ameren Missouri set out its rationale for increasing its rates in the direct testimony it filed along with its tariff on July 3, 2014. In addition to its filed testimony, Ameren Missouri provided work papers and other detailed information and records to the Staff of the Commission, Public Counsel, and to the intervening parties. Those parties then had the opportunity to review Ameren Missouri's testimony and records to determine whether the requested rate increase was justified.

Where the parties disagreed, they prefiled written testimony to raise those issues to the attention of the Commission. All parties were given an opportunity to prefile three rounds of testimony – direct, rebuttal, and surrebuttal. The process of filing testimony and responding to the testimony filed by other parties revealed areas of agreement that resolved some issues and areas of disagreement that revealed new issues. On February

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[8] Moehn Direct, Ex. 28, Page 5, Lines 8-9.

[9] Moehn Direct, Ex. 28, Page 5, Lines 10-20.

[10] Ameren Missouri Initial Post Hearing Brief, Page 2, Footnote 2.

18, the parties filed a list of the issues they asked the Commission to resolve. Some of the issues identified at that time were later resolved by unanimous stipulation and agreement. The unresolved issues will be addressed in this report and order.

Conclusions of Law Regarding Jurisdiction

A. Ameren Missouri is a public utility, and an electrical corporation, as those terms are defined in Section 386.020(43) and (15), RSMo (Cum. Supp. 2013). As such, Ameren Missouri is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo 2000.

B. Section 393.140(11), RSMo 2000, gives the Commission authority to regulate the rates Ameren Missouri may charge its customers for electricity. When Ameren Missouri filed a tariff designed to increase its rates, the Commission exercised its authority under Section 393.150, RSMo 2000, to suspend the effective date of that tariff for 120 days beyond the effective date of the tariff, plus an additional six months.

Conclusions of Law Regarding the Determination of Just and Reasonable Rates

A. In determining the rates Ameren Missouri may charge its customers, the Commission is required to determine that the proposed rates are just and reasonable.[11] Ameren Missouri has the burden of proving its proposed rates are just and reasonable.[12]

B. In determining whether the rates proposed by Ameren Missouri are just and reasonable, the Commission must balance the interests of the investor and the

[11] Section 393.150.2, RSMo 2000.

[12] Section 393.150.2, RSMo 2000.

consumer.[13] In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[14]

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[15]

The Supreme Court has further indicated:

> '[R]egulation does not insure that the business shall produce net revenues.' But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure

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[13] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603, (1944).

[14] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 690 (1923).

[15] *Bluefield,* at 692-93.

> confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[16]

C. In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

> Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.[17]

D. Furthermore, in quoting the United States Supreme Court in *Hope Natural Gas*, the Missouri Court of Appeals said:

> [T]he Commission [is] not bound to the use of any single formula or combination of formulae in determining rates. Its rate-making function, moreover, involves the making of 'pragmatic adjustments.' … Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling. It is not theory but the impact of the rate order which counts.[18]

The Rate Making Process

The rates Ameren Missouri will be allowed to charge its customers are based on a determination of the company's revenue requirement. Ameren Missouri's revenue requirement is calculated by adding the company's operating expenses, its depreciation on plant in rate base, taxes, and its rate of return multiplied by its rate base. The revenue requirement can be expressed as the following formula:

Revenue Requirement = E + D + T + R(V-AD+A)
Where: E = Operating expense requirement
D = Depreciation on plant in rate base
T = Taxes including income tax related to return

[16] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944) (citations omitted).

[17] *Federal Power Commission v. Natural Gas Pipeline Co*. 315 U.S. 575, 586 (1942).

[18] *State ex rel. Associated Natural Gas Co. v. Pub. Serv. Comm'n*, 706 S.W. 2d 870, 873 (Mo. App. W.D. 1985).

R = Return requirement
(V-AD+A) = Rate base

For the rate base calculation:

V = Gross Plant
AD = Accumulated depreciation
A = Other rate base items

All parties accept the basic formula. Disagreements arise over the amounts that should be included in the formula.

The Issues

1. Regulatory Policy and Economic Considerations.

This is not a true issue in that the parties do not ask the Commission to resolve any questions regarding the particulars of Ameren Missouri's request for a rate increase. Instead, the parties presented testimony regarding general policy matters that affect the Commission's decision making regarding the detailed issues that will be addressed later in this report and order. Because this is only a general policy discussion, the Commission will not make findings of fact or conclusions of law about these policy matters.

Testimony was offered by the parties regarding the difficult economic situation that is currently facing individuals and businesses in Missouri in general and in Ameren Missouri's service territory in particular. Aside from the testimony offered at the evidentiary hearing, the Commission also heard that message from Ameren Missouri's customers during the twelve, well-attended, local public hearings the Commission conducted throughout Ameren Missouri's service territory.

The Commission was created to serve the public interest, and it takes that responsibility very seriously. The Commission serves the public interest by establishing just and reasonable rates, and the Commission has endeavored to do so in this report and order.

Many customers are already having a hard time paying their electric bills. Increasing Ameren Missouri's rates may make it even harder for some customers to pay their bills. However, a just and reasonable rate does not necessarily mean a lower rate.

2. Weather Normalization (SPS and LGS Classes)

What level of sales to Noranda should be assumed for the test year for purposes of establishing billing units?

Findings of Fact:

1. Although this issue is described as weather normalization, it has little to do with the weather. Rather it concerns the amount of electricity that Ameren Missouri sells to Noranda for its New Madrid smelter. Noranda is Ameren Missouri's largest customer, representing over ten percent of Ameren Missouri's retail sales. Historically, it has a very stable and consistent load that varies very little while the aluminum smelter is in full production.[19] Given its unique characteristics, Noranda has its own rate as the only member of the Large Transmission Service (LTS) rate class.

2. During the test year for this case, which was the twelve months ending March 31, 2014, Ameren Missouri sold Noranda approximately 4.2 million mega-watt hours (MWhs) of electricity. Staff proposes to use that figure to set Ameren Missouri's rate.[20]

3. Beginning in July 2014, Noranda began to experience a production slow-down due to an unusually high number of "pot" failures. The lower production means Noranda bought less electricity from Ameren Missouri during that period. However, Noranda anticipated returning to full production by the end of March 2015.[21]

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[19] Wills Amended Rebuttal, Ex. 53, Pages 17-18, Lines 22-23, 1-2.

[20] Staff Report – Revenue Requirement, Ex. 202, Page 66, Lines 14-17.

[21] Phillips Surrebuttal, Ex. 516, Page 4, Lines 1-11.

4. Ameren Missouri is concerned about the drop in production and the corresponding drop in sales. In its rebuttal testimony, Ameren Missouri proposed to set the measure of sales to Noranda based on the actual sales in November and December of 2014, the last two months of the true-up period. That would result in an annual level of approximately 3.8 million MWhs.[22]

5. At the hearing, Ameren Missouri amended its position to propose the use of a three-year average to determine the level of sales. The three-year average would include the most recent year in which Noranda saw decreased production due to the pot failures. That would result in an annual level of approximately 4.1 million MWhs.[23]

6. As an alternative for the Commission's consideration, Ameren Missouri also offered a ten-year average calculation that results in an annual level of approximately 4.0 million MWhs.[24] However, that ten year average would include 2009 when Noranda's production was cut nearly in half by a power outage resulting from a severe ice storm.[25] Ameren Missouri suggested the ten-year average including the reduced production due to the ice storm would be appropriate if the Commission denies the company's request to recover costs deferred under an AAO related to that ice storm.[26]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

In setting Ameren Missouri's volumetric rates to allow it to recover its costs to serve

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[22] Wills Amended Rebuttal, Ex. 53, Page 20, Lines 1-11.

[23] Wills Surrebuttal, Ex. 54, Page 8, Table SMW-2.

[24] Wills Surrebuttal, Ex. 54, Page 8, Table SMW-2.

[25] Wills Surrebuttal, Ex. 54, Page 6, Table SMW-1.

[26] Wills Surrebuttal, Ex. 54, Page 7, Lines 11-16.

Noranda, the Commission must determine how many billing units the company is likely to sell to Noranda in a year. The costs are then divided over the billing units to set the rate. If Ameren Missouri is able to sell more billing units than were factored into the rate, it collects more money than its cost to serve. Conversely, if it sells fewer units than were factored into its rate, it will not cover its full cost.

The Commission anticipates that Noranda will return to full production while the rates set in this case remain in effect, which is also the production level experienced in the test year. Setting its rate based on the test year experience will allow Ameren Missouri a fair opportunity to recover its cost to serve Noranda. If the Commission were to set those rates based on an average number that includes the unusually reduced production resulting from the ice storm in 2009, or the elevated level of pot failures in 2014, Ameren Missouri would be in a position to collect a windfall if, as anticipated, Noranda returns to full production in 2015.

Of course, there is a possibility that Noranda will not return to full production as anticipated, but Ameren Missouri's shareholders should bear the business risk of reduced sales, not its ratepayers. The Commission will set the level of annual billing units at 4.2 million Mega-Watt hours (MWh) of electricity as recommended by Staff.

3. Income Tax

A. Should Ameren Missouri's Net Operating Loss Carryforward Related to ADIT be included in Ameren Missouri's rate base?

Findings of Fact:

1. This issue concerns Ameren Missouri's test year Net Operating Loss Carryforward (NOLC) associated with its Accumulated Deferred Income Tax (ADIT)

balance.

2. ADIT represents assets or liabilities for cumulative amounts of deferred income taxes resulting from differences between book accounting and income-tax accounting.[27] For example, tax law sometimes allows a company to claim accelerated depreciation in calculating its taxes.[28]

3. Since in the short term it pays less in taxes, the company is able to keep more cash. But, because the company can only depreciate its assets once, the accelerated depreciation will reduce the depreciation expense the company would otherwise use to reduce its taxes in future years. Essentially the ADIT allows the company to have the use of "free" cash between the time the ADIT is acquired and the time the increased taxes will come due.[29] Because the ADIT represents "free" cash to the company, ratepayers should not be required to pay for it and the company should not be allowed to earn a return on it. Thus ADIT is removed from the company's ratebase.[30]

4. However, when bonus depreciation and other tax deductions grow so large as to push the company's taxable income into the negative, the available tax deduction cannot offset any tax liability and no "free" cash is generated. In that circumstance, the company must record an offsetting deferred tax asset for Net Operating Loss Carryforward (NOLC). The NOLC offsets the ADIT, which would decrease the company's rate base, and therefore, the NOLC has the effect of increasing the rate base.[31]

5. For many years, Ameren Corporation, of which Ameren Missouri is an

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[27] Brosch Direct, Ex. 501, Page 13, Lines 4-14.

[28] Brosch Direct, Ex. 501, Page 13, Lines 15-21.

[29] Warren Rebuttal, Ex. 48, Pages 11-12.

[30] Brosch Direct, Ex. 501, Page 15, Lines 1-17.

[31] Brosch Surrebuttal, Ex. 502, Page 5, Lines 18-23.

affiliate, has filed a consolidated tax return on behalf of itself and all its subsidiary corporations, including Ameren Missouri. Filing a consolidated return means that all tax losses of the group are used to offset the taxable income of the entire group.[32] Filing a consolidated tax return benefits Ameren Corporation and in most years benefits Ameren Missouri as well. Furthermore, once a company chooses to file a consolidated tax return, it cannot switch to filing separate returns for its affiliates except by special permission from the IRS.[33]

6. For tax years 2008 through 2012, the calculation of NOLC allocated to Ameren Missouri through the filing of a consolidated return had the effect of substantially increasing the NOLC allocated to Ameren Missouri, and thus decreasing the company's rate base.[34] In 2013 and 2014, Ameren Missouri produced a large amount of taxable income but could not use that accumulated NOLC because the Ameren group as a whole had a tax loss.[35] As a result, the NOLC is larger than it would otherwise be and rate base is approximately $51.1 million larger at the end of 2014 than it would be if Ameren Missouri had filed a separate tax return.[36] However, in future years, the balance could switch back, and Ameren Missouri's ratepayers would once again benefit from the use of the consolidated return.[37]

7. Rather than use Ameren Missouri's actual NOLC that was determined using the consolidated tax return actually filed, MIEC's witness, Michael Brosch, urges the

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[32] Warren Rebuttal, Ex. 48, Page 18, Lines 12-17.

[33] Warren Rebuttal, Ex. 48, Page 23, Lines 14-18.

[34] Warren Rebuttal, Ex. 48, Page 26, Table VII.

[35] Brosch Direct, Ex. 501, Page 25, Lines 16-21.

[36] Brosch Surrebuttal, Ex. 502, Schedule MLB-10, page 2.

[37] Transcript, Page 360, Lines 4-10.

Commission to recalculate NOLC as if Ameren Missouri had filed a separate tax return.[38] However, he does not argue that the separate tax return, stand-alone, calculation should necessarily be used in future rate cases. Rather he argues the Commission should calculate NOLC in each future case by the method that creates the lowest NOLC rate base addition, to the benefit of ratepayers and the detriment of the company.[39]

8. Ameren Corporation and its affiliated companies have entered into a Tax Allocation Agreement that governs the allocation of consolidated annual income tax responsibility among the members of the consolidated tax group and defines the amounts recorded on the utility's books.[40]

9. There is no evidence in this case to show that Ameren's Tax Allocation Agreement is structured in a way that would be detrimental to Ameren Missouri and its ratepayers. Instead, for several years, Ameren Missouri's ratepayers benefited from a lower rate base because of the Tax Allocation Agreement. The Tax Allocation Agreement has not changed, but in more recent years ratepayers have not benefitted from that agreement, although that may change again in the future. That fluctuation does not mean the agreement is unreasonable, and there is no evidence the fluctuation was intentionally created in order to change who benefits from the Tax Allocation Agreement.

Conclusions of Law:

A. MIEC points to the Commission's affiliate transaction rule as support for its proposal to calculate NOLC in whichever manner results in the lower rate base for the company. Commission Rule 4 CSR 240-20.015(2) says:

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[38] Brosch Direct, Ex. 501, Page 26, lines 14-18.

[39] Brosch Surrebuttal, Ex. 502, Page 6, Lines 19-25.

[40] Brosch Surrebuttal, Ex. 502, Page 6, Lines 8-12.

(2) Standards.

(A) A regulated electrical corporation shall not provide a financial advantage to an affiliated entity. For the purposes of this rule, a regulated electrical corporation shall be deemed to provide a financial advantage to an affiliated entity if –

1. It compensates an affiliated entity for good or services above the lesser of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation to provide the goods or services for itself; or

2. It transfers information, assets, goods or services of any kind to an affiliated entity below the greater of –

A. The fair market price; or

B. The fully distributed cost to the regulated electrical corporation.

B. Section 4 CSR 240-20.015(1)(B) defines affiliate transaction as:

Affiliate transaction means any transaction for the provision, purchase or sale of any information, asset, product or service, or portion of any product or service, between a regulated electrical corporation and an affiliated entity, …

C. The Commission's affiliate transaction rules do not apply in this situation because there is no transaction involved. The affiliate transaction rules are intended to control transfers of goods or services between regulated utilities and their affiliates. So for example, if Ameren Missouri wants to purchase legal services from an affiliate such as Ameren Services Company, it cannot pay more than the lesser of market cost or its cost to provide the services for itself. In that context that is a reasonable restriction to ensure the regulated utility is not giving a sweetheart contract to an affiliate at the ratepayers' expense.

D. But here, where there is no transaction, the restrictions of the rule have no meaning. How could the fair market price or the fully distributed cost even be calculated? MIEC can only fall back to the basic policy behind the affiliate transaction rule, which reasonably states that regulated utilities should not be allowed to structure corporate arrangements in a way that disadvantages regulated utilities and thereby disadvantages ratepayers.

Decision:

Ameren Missouri proposes to use the NOLC it has actually accumulated rather than a hypothetical NOLC proposed by MIEC and supported by Staff, MIEC advocates a policy that arrangements between affiliates should always be interpreted in a manner that benefits ratepayers, even if that results in a detriment to the utility. There is no basis in law or fact for such a policy. The Commission must balance the interests of ratepayers and shareholders to set just and reasonable rates. Ameren Missouri's position is fair and will be adopted.

B. Should the Company's IRC Section 199 Deduction be computed without regard to Net Operating Loss Carryovers from prior years in determining the Company's income tax expense?

Findings of Fact:

1. The Internal Revenue Code Section 199 deduction is also referred to as the domestic production deduction or DPD. The DPD is a tax incentive provided to manufacturers, including producers of electricity. It allows the tax payer to take a tax deduction equal to 9% of the lesser of certain qualified net income or the taxpayer's taxable income. Under the tax law, the DPD is calculated on a consolidated basis.[41] Recognition of a DPD would reduce Ameren Missouri's tax expense and would therefore reduce rates for ratepayers.

2. In its initial filing for this case, Ameren Missouri calculated a DPD of $30.8 million.[42] MIEC's witness, Michael Brosch recalculated that deduction at $36.9 million in

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[41] Warren Rebuttal, Ex. 48, Page 31, Lines 6-12.

[42] Brosch Direct, Ex. 501, Page 9, Lines 21-23.

his direct testimony.[43]

3. In his rebuttal testimony, Ameren Missouri's witness, James Warren, testified that both Mr. Brosch and Ameren Missouri's initial calculation of the DPD are incorrect. Both calculations assumed that Net Operating Loss Carryforward (NOLC) was not includable. In fact, Mr. Warren explained that Treasury Regulations applicable to the DPD do allow for the consideration of NOLC in calculating DPD.[44] Including the NOLC in the calculations would reduce Ameren Missouri's taxable income and thereby reduce the DPD.[45]

4. Ameren Missouri has not utilized NOLC in its calculation of its DPD in past rate cases and only proposed to do so in rebuttal testimony offered in this case. Both MIEC[46] and Staff[47] contend the use of NOLC should not be allowed because it has not been used in the past. MIEC's witness, Michael Brosch, also expressed concern that the NOLC should not be used because of the uncertainty that Ameren Missouri will even have an NOLC in future years.[48]

5. As an alternative to totally eliminating consideration of NOLC in calculating the DPD, MIEC proposed a DPD calculation that uses only the NOLC that would be calculated assuming that Ameren Missouri had filed a separate tax return rather than the

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[43] Brosch Direct, Ex. 501, Schedule MLB-4, Page 2.

[44] Warren Rebuttal, Ex. 48, Pages 32-33, Lines 11-25, 1-2.

[45] Hanneken Surrebuttal, Ex. 218, Page 14, Lines 11-13. The testimony calculates an amount of the deduction that is listed as highly confidential so will not be stated in this order.

[46] Brosch Surrebuttal, Ex. 502, Page 22, lines 5-8. See also, Transcript, Pages 410-411, Lines 17-25, 1.

[47] Hanneken Surrebuttal, Ex. 218, Page 15, Lines 1-6. *See also*, Transcript, Page 375, Lines 17-22.

[48] Transcript, Page 411, Lines 2-14.

consolidated return it actually files with Ameren Corporation and its affiliates. That calculation supported a DPD estimate of $7.9 million.[49]

6. The use of a hypothetical stand-alone tax return in place of the actual consolidated return is the same issue as was addressed in the previous income tax issue. All parties agree the question should be resolved in the same way for both sub-issues.

Conclusions of Law:

The Commission makes no additional conclusions of law for this sub-issue.

Decision:

Ameren Missouri demonstrated that the Internal Revenue Code allows for the use of NOLC in calculating Ameren Missouri's DPD. The Internal Revenue Code does not require the Commission to allow its use for regulatory purposes, but the fact that NOLC has not been included in that calculation in past rate cases is not a persuasive reason to forbid its inclusion in this case. MIEC's suggestion that inclusion of NOLC makes the DPD uncertain because Ameren Missouri may not have NOLC in the future is based only on speculation and on MIEC's failed effort to require NOLC to be calculated on a hypothetical stand-alone basis. The Commission concludes, consistent with its decision in the previous income tax issue, that Ameren Missouri's method for calculation of its DPD is appropriate.

4. Amortizations

A. Should the amount of solar rebates paid by Ameren Missouri and recorded to a solar rebate regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement using a 3-year amortization period?

Findings of Fact:

1. In a non-unanimous stipulation and agreement filed in Commission File No. ET-2014-0085, Ameren Missouri, Staff, Public Counsel, MIEC, and numerous other parties

[49] Brosch Surrebuttal, Ex. 502, Page 22-23, and Schedule MLB-4 Revised.

agreed that Ameren Missouri would continue to make the solar rebate payments required by Missouri's Renewable Energy Standard, Section 393.1030 RSMo (Cum. Supp. 2013), until a specified level of $91.9 million in rebates was incurred by the company. That agreement also provides for creation of a regulatory asset to be considered for recovery in rates after December 31, 2013, in a general rate case. Ameren Missouri was required to record to that asset the actual amount of solar rebates paid, not to exceed $91.9 million, plus 10 percent.[50] No one objected to that stipulation and agreement, and the Commission approved it in an order issued on November 13, 2013.[51]

2. Ameren Missouri has deferred and accumulated approximately $88.1 million of solar rebates through December 31, 2014. Coupled with a 10 percent added cost of $8.8 million as provided in the stipulation and agreement, Ameren Missouri is seeking to recover approximately $96.9 million. By terms of the stipulation and agreement, that amount is to be amortized over three years, so $32.3 million would be included in Ameren Missouri's rates to be established in this case.[52]

3. MIEC and Consumers Council contend Ameren Missouri should not be allowed to recover any additional revenues to recover any of the solar rebate expense deferred under the stipulation and agreement. They assert that Ameren Missouri's earnings from retail rates during the period when the rebate costs were incurred already covered those costs.[53] Essentially, they argue that Ameren Missouri over-earned during the period the costs were incurred, so it should not be allowed to again recover those costs

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[50] Ex. 55.

[51] *In the Matter of Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates*, Order Approving Stipulation and Agreement, File No. ET-2014-0085, November 13, 2013.

[52] Cassidy Surrebuttal, Ex. 211, Page 4, Lines 3-11.

[53] Meyer Direct, Ex. 513, Pages 11-12, Lines 18-21, 1-2.

in the rates to be established in this case.

4. As proof that Ameren Missouri has over-earned, MIEC and Consumers Council point to Ameren Missouri's raw, unadjusted surveillance reports to claim that for most of the period from August 2012 through September 2014, Ameren Missouri collected enough revenue above its authorized revenue level to fully recover its solar rebate payments.[54]

5. However, unadjusted, per-book surveillance reports have only a limited value.[55] In the recent rate complaint case, the complainants attempted to use the same, slightly adjusted surveillance reports as the basis for setting new rates. In rejecting that attempt, the Commission found:

> It is important to understand that the earnings levels reported in the surveillance reports are actual per book earnings of the utility and cannot be compared directly to an authorized return on equity to determine whether a utility is overearning. Actual per book earnings are often computed differently than earnings used for the purpose of establishing rates. When setting rates, the Commission looks at "normal" levels of ongoing revenues and expenses, while book earnings can be affected by abnormal, non-recurring and extraordinary events. A good example of this is the weather.[56]

In this case, MIEC's witness, Greg Meyer simply pointed to the surveillance reports, without making any adjustments, to claim that Ameren Missouri has been over-earning. The Commission finds that the unadjusted per-book surveillance reports are not sufficient to establish that Ameren Missouri over-earned during the period of deferral.

6. Even if the unadjusted per-book surveillance reports were accepted as the basis for a claim of over-earning, the over-earning they purport to show is not significant.

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[54] Meyer Direct, Ex. 513, Page 13 and Schedule GRM-3.

[55] Transcript, Page 536, Lines 9-10.

[56] *Noranda Aluminum, Inc., et al. v. Union Electric Company*, File No. EC-2014-0223, Report and Order, October 1, 2014, Finding of Fact No. 13, Page 8.

For calendar year 2013, the per-book surveillance report showed that Ameren Missouri's actual earned return on equity was 10.34 percent, compared to an authorized return on equity of 9.8 percent.[57] For calendar year 2014, the per-book surveillance report showed that Ameren Missouri actual earned return on equity was 9.71 percent, again compared to an authorized return on equity of 9.8 percent.[58] Over the entire 2013 and 2014 period the per-book over-earning would amount to less than 0.50 percent.[59]

Conclusions of Law:

A. In 2008, Missouri voter adopted by initiative Proposition C, which creates a Renewable Energy Standard. That standard, which is codified in Sections 393.1025 and 393.1030 RSMo (Cum. Supp. 2013), requires investor-owned electric utilities, such as Ameren Missouri, to obtain a specified percentage of their electric generation from renewable energy resources, provided that the cost to do so does not raise retail rates by more than one percent. More specifically, Section 393.1030.3 requires investor-owned electric utilities to pay solar rebates to their customers who choose to install new or expanded solar energy generating facilities on their property.

B. Section 393.1030.2(4), RSMo (Cum. Supp. 2013), provides that the electric utility may seek to recover the costs of complying with the Renewable Energy Standard, including solar rebate payments, outside a regular rate case by means of a Renewable Energy Standard Rate Adjustment Mechanism (RESRAM). Ameren Missouri does not have a RESRAM, as will be explained later, but the inclusion of that possibility illustrates that the policy of the Renewable Energy Standard statute supports the recovery of those

[57] Ex. 524.

[58] Ex. 528.

[59] Transcript, Page 585, Lines 9-14.

costs by the utility.

C. Section 393.1030.3 of the statute allows the utility to petition the Commission to cease payment of the solar rebates if paying additional rebates will cause the utility to exceed the allowable one percent increase in retail rates. Ameren Missouri filed such a petition in the fall of 2013. That petition was assigned File No. ET-2014-0085 by the Commission.

D. File No. ET-2014-0085 was ultimately resolved by a stipulation and agreement[60] that was approved by the Commission in an order issued on November 13, 2013.[61]

E. The stipulation and agreement allowed Ameren Missouri to discontinue paying solar rebates after it had paid a total of $91.9 million for rebates incurred after July 31, 2012. It provides that such solar rebate payments, with an additional ten percent carrying charge, are to be included in a regulatory asset to be considered for recovery in rates after December 31, 2013 in a general rate case. The stipulation and agreement also provides that the costs are to be amortized over three years when they are recovered in rates.

F. In the stipulation and agreement, the signatories agree "not to object to Ameren Missouri's recovery in retail rates of prudently paid solar rebates." There is a footnote to that statement which says:

> Given the Signatories' agreement that the specified amount should be paid, the only questions in future general rate proceedings regarding the recovery of solar rebate payments is whether the claimed solar rebate payments have been made and whether they were prudently paid under the Commission's

[60] Ex. 55.

[61] *In the Matter of Ameren Missouri's Application for Authorization to Suspend Payment of Solar Rebates*, Order Approving Stipulation and Agreement, File No. ET-2014-0085, November 13, 2013.

> RES rules and Ameren Missouri's tariff. 'Prudently paid' relates only to whether Ameren Missouri paid the proper amount due to an applicant for a rebate, paid it to the proper person or entity, and paid it in accordance with the Commission's RES rules and Ameren Missouri's tariffs.

In return, as part of the stipulation and agreement, Ameren Missouri gave up its right under the statute to seek recovery of the solar rebate costs outside a rate case through a RESRAM.

G. MIEC signed the stipulation and agreement, Consumers Council did not. Ameren Missouri contends MIEC has violated the terms of the stipulation and agreement by challenging Ameren Missouri's recovery of the solar rebate payments in this case on a basis other than prudent payment. As a remedy, it asks the Commission to strike all the testimony and argument offered by MIEC on this issue. Consumers Council did not sign the stipulation and agreement, and Ameren Missouri concedes that it can argue against recovery of the solar rebates on any basis that it wishes. However, Ameren Missouri asserts that MIEC procured the services of Consumers Council's witness, James Dittmer, on behalf of Consumers Council and, on that basis, asks the Commission to strike his testimony as well.

H. Commission rule 4 CSR 240-20.090(10) requires each electric utility with a fuel adjustment clause (a rate adjustment mechanism or RAM within the words of the regulation) to submit a quarterly Surveillance Monitoring Report. The required contents of the quarterly report are described by Commission rule 4 CSR 240-3.161(6). That regulation also requires that such reports be treated as highly confidential.

I. Rate making is designed to be forward looking. The goal is to choose a representative test year to estimate what costs will be when rates are in effect, not to make adjustments for past earning levels.[62] The practice of setting future rates to adjust for past earning levels is condemned as retroactive ratemaking that would deprive either the utility or its customers of their property without due process.[63]

J. The Commission only sets the rates that Ameren Missouri, or any other utility, may charge its customers. It does not determine a maximum or minimum return the utility may earn from those rates. Sometimes, the established rate will allow the utility to earn more than was anticipated when the rate was established. Sometimes, the utility will earn less than anticipated. But the rate remains in effect until it is changed by the Commission, and so long as the utility has charged the authorized rate, it cannot be made to refund any "over-earnings," nor can it be allowed to collect any "under-earnings" from its customers.[64]

Decision:

The Commission will fully address this issue on its merits and will not strike any testimony. This is not the proper forum to determine whether MIEC violated the terms of the stipulation and agreement or the order of the Commission that directed the signatories to comply with that agreement. If Ameren Missouri wishes to further pursue a remedy for what it believes to be a breach of the stipulation and agreement it may do so in a new proceeding of its choosing.

This issue is about the deferral of Ameren Missouri's solar rebate costs for consideration for recovery in this rate case. Generally, the Commission uses a test year to determine which of a utility's expenses will be considered when setting just and reasonable

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[62] *State ex rel. Southwestern Bell Tele. Co. v. Pub. Serv. Comm'n*, 645 S.W.2d 44, 48 (Mo. App. W.D. 1982).

[63] *State ex rel. Util. Consumers Council of Mo, Inc. v. Pub. Serv. Comm'n*, 585 S.W.2d 41, 58 (Mo. banc 1979).

[64] *Straube v. Bowling Green Gas Co.,* 227 S.W.2d 666 (Mo. 1950).

rates for the future. But sometimes the utility incurs an expense that the Commission believes should be deferred for consideration for recovery in a future rate case. The classic example is a severe storm that causes the electric utility to incur unexpectedly large costs. If that storm occurs outside the test year for the next rate case, the company would never be able to recover those unexpected costs.

But storms are not the only reason a deferral may be allowed. There may be other public or regulatory policy reasons why a utility should be allowed to defer a cost for consideration for recovery in a future rate case. For this issue, the costs that have been deferred are the costs Ameren Missouri paid to give rebates to its customers who installed home solar power generating units. The people of Missouri imposed the solar rebate requirement by voting for Proposition C because they believe that renewable energy in general, and solar energy in particular, is important to the well-being of our state. That legislation required Ameren Missouri and Missouri's other investor-owned electric utilities to be the conduit to encourage individuals to invest in solar energy. Therefore, it is entirely appropriate to allow Ameren Missouri to defer those costs for recovery in its next rate case.

As has been said many times, the deferral of a cost is not ratemaking treatment. That is, the deferral of a cost does not guarantee recovery of that cost in future rates. The Commission must determine within the context of a rate case whether recovery of the deferred cost is appropriate. But, usually the policy reason that justified the deferral still applies when it comes time to decide whether the deferred costs should be included when determining a future rate.

MIEC and the Consumers Council argue for what is in essence an earnings test to be applied to all deferrals. Under such a test, the Commission would have to determine by how many dollars a utility over-earned during the deferral and then, dollar for dollar, the Commission would have to deny recovery of every dollar deferred above the return authorized in the last rate case. Such an earnings test fundamentally misunderstands the ratemaking process and would be completely unworkable in practice.

The Commission sets rates in a forward looking process using a test year to evaluate the amount of revenue the utility needs to earn to recover its costs and to have a reasonable opportunity to earn a profit. The utility is not guaranteed a profit, just an opportunity to earn that profit. Sometimes, circumstances make it difficult for the utility to earn that profit. Perhaps the summer is cooler than normal and people do not use their air conditioners so the utility does not sell as much electricity as anticipated. Or, perhaps, a generating plant goes down, resulting in unanticipated capital expenditures for the utility. Sometimes, circumstances favor the utility and it is able to earn more revenue than was anticipated when its rates were set. Whether the utility earns more or less revenue than was anticipated when the Commission set its rates does not necessarily indicate over- or under-earnings such that the utility's rate are no longer just and reasonable, though that can be one relevant factor of many to consider when setting new rates. Thus, in most cases, mention of over- or under-earnings is just a shorthand way of discussing whether the Commission should examine a utility's existing rates to determine if they are still just and reasonable. If Staff or some other party looks at the utility's earnings and finds that the utility is consistently earning above the benchmark return on equity established in the last rate case, they may, by filing a complaint, petition the Commission to again undertake the process of re-determining the utility's just and reasonable rates. If the utility looks at its earnings and finds it is not earning what it believes it should, it can begin the rate review process by filing a tariff to start the rate case process.

The surveillance reports that have been discussed extensively in this case were established to make that information about Ameren Missouri's earnings available to all interested stakeholders so that they could decide whether the process to establish a new rate should be undertaken. But those surveillance reports do not themselves determine what an appropriate rate should be, nor do they establish either a ceiling or a floor on the earnings of the utility. Most fundamentally, in isolation, surveillance reports do not establish that a utility has under or over earned for purposes of setting rates.

Ameren Missouri's solar rebate costs were appropriately deferred pursuant to the Commission order approving those costs and their deferral, and now may be recovered through the rates set in this rate case, amortized over three years. No offset for over-earnings is appropriate.

B. Should the amount of pre-MEEIA energy efficiency expenditures incurred by Ameren Missouri and recorded to a regulatory asset through the end of the true-up period be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. In previous rate cases, the Commission allowed Ameren Missouri to defer certain pre-MEEIA energy efficiency expenditures for subsequent recovery, amortized over several years. For this case, Ameren Missouri would defer and recover an additional $3.3 million in expenditures incurred between the July 31, 2012 true-up cutoff date and January 2, 2013 effective date of the report and order in Ameren Missouri's last rate case, ER-2012-0166, amortized over six years. Staff would also make certain adjustments to the

previously allowed deferrals.[65]

2. Ameren Missouri does not contest the treatment of these costs proposed by Staff.[66] MIEC once again opposes recovery of these deferrals because of the alleged over-earnings by Ameren Missouri.

Conclusions of Law:

A. The Missouri Energy Efficiency Investment Act,[67] generally known as MEEIA, is a statute designed to encourage electric utilities to invest in energy efficiency measures that will reduce the need to invest in energy production infrastructure. The goal of the statute is to make such investments profitable, and to that end, Section 393.1075.3 establishes the policy of the state to allow electric utilities to recover "all reasonable and prudent costs of delivering cost-effective demand-side programs."

Decision:

Public policy in Missouri, as indicated by MEEIA, favors allowing electric utilities to fully recover their expenditures on energy efficiency programs. As explained with regard to the Solar Rebate Payment Deferral issue, no offset for over-earnings is appropriate here. Deferral and recovery of the pre-MEEIA energy efficiency expenditures incurred by Ameren Missouri shall be made in the manner described by Staff.

C. Should the amount of Fukushima flood study costs incurred by Ameren Missouri and recorded to a regulatory asset be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

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[65] Staff Report Revenue Requirement, Ex. 202, Page 58, Lines 17-20, and Pages 120-121, Lines 27-31, 1-6.

[66] Transcript, Page 543, Lines 1-7.

[67] Section 393.1075, RSMo (Cum. Supp. 2013).

Findings of Fact:

1. After the Fukushima Tsunami, the Nuclear Regulatory Agency required all U.S. utilities that operate nuclear power plants to perform a study of the threat of flooding at those facilities.[68] Staff and Ameren Missouri agree the $926,561 cost of the study should be deferred for recovery over a ten-year amortization period.[69] MIEC once again opposes recovery of these deferrals because of the alleged "over-earnings" by Ameren Missouri.

2. The deferral of the cost of the study is consistent with applicable accounting standards.[70]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The deferral and recovery of the Fukushima study costs is consistent with good public and regulatory policy. Ameren Missouri may recover those costs, amortized over a ten-year period.

5. Noranda AAO

Should the sums authorized for deferral in Case No. EU-2012-0027 be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. On January 27-28, 2009, a major ice storm disrupted the power supply to Noranda's aluminum smelter. The molten aluminum hardened in two of the three

[68] Transcript, Page 509, Lines 5-13.

[69] Staff Report Revenue Requirement, Ex. 202, Page 122, Lines 4-6.

[70] Transcript, Page 543, Lines 8-16.

production lines, and Noranda's output was reduced for most of that year. As a result, Noranda bought much less electricity from Ameren Missouri than had been anticipated when Ameren Missouri's rates were set. Because Noranda purchased less power from Ameren Missouri, the company was unable to recover a portion of the revenue it would otherwise have recovered through the sale of electricity to Noranda.[71]

2. On the same day as the start of the ice storm, January 27, 2009, the Commission issued a report and order in Ameren Missouri's (then AmerenUE's) rate case. In that report and order, the Commission for the first time granted the company's request for a fuel adjustment clause.[72]

3. The existence of the fuel adjustment clause exacerbated the problem Ameren Missouri faced because of the Noranda outage. Ameren Missouri could resell at least part of the power it would otherwise have sold to Noranda on the off-system sales market. But as an off-system sale, 95 percent of the revenue derived from that sale would flow through the FAC to be netted against fuel costs, and would therefore benefit ratepayers rather than Ameren Missouri's shareholders.[73]

4. Ameren Missouri tried to rectify that problem by filing an application for rehearing in the rate case seeking to have the newly minted Fuel Adjustment Clause modified. That motion was opposed by the other parties, and on February 19, 2009, the Commission denied the motion for rehearing, pointing out that it was not possible to reopen the record to take additional evidence and still conclude the case before the March 1, 2009

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[71] Cassidy Rebuttal, Ex. 210, Pages 2-3, Lines 15-23, 1-2.

[72] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo.P.S.C.3d 306 (2009).

[73] Cassidy Rebuttal, Ex. 210, Page 3, Lines 2-9.

operation of law date.[74]

5. In an attempt to get around the effect of the Fuel Adjustment Clause it had just obtained, Ameren Missouri sold part of the power it would otherwise have sold to Noranda under long-term supply contracts to American Electric Power Operating Companies (AEP) and Wabash Valley Power Association, Inc. In making those sales, Ameren Missouri believed it could avoid having to run the replacement sales through its fuel adjustment clause (FAC). But in a subsequent prudence review of the Fuel Adjustment Clause the Commission disagreed, finding that the sales to AEP and Wabash were off-system sales that had to be run through the FAC. Thus, 95 percent of the benefit of those sales was allotted to Ameren Missouri's ratepayers by operation of the FAC, and was not available to allow Ameren Missouri to cover its fixed costs that would otherwise have been recovered through sales to Noranda.[75]

6. Ameren Missouri appealed the Commission's order in the prudence review cases, but the Western District Court of Appeals affirmed the Commission's decision.[76] After the Commission issued its decision in the first prudence review, and while the appeal of that decision was pending, Ameren Missouri applied to the Commission for an Accounting Authority Order (AAO) seeking to defer fixed costs to serve Noranda that were

[74] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Order Denying AmerenUE's Application for Rehearing, Case No. ER-2008-0318, 18 Mo.P.S.C.3d 441 (2009).

[75] Cassidy Rebuttal, Ex. 210, Pages 3-4, Lines 19-23, 1-8. The two prudence reviews cases in which the Commission made those rulings are: *In the Matter of the First Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, Report and Order, File No. EO-2010-0255, April 27, 2011; and *In the Matter of the Second Prudence Review of Costs Subject to the Commission-Approved Fuel Adjustment Clause of Union Electric Company, d/b/a Ameren Missouri*, Report and Order, File No. EO-2012-0074, July 31, 2013.

[76] *State ex rel. Union Elec. Co. v. Public Service Com'n*, 399 S.W.3d 467 (Mo. App. W.D.2013).

not recovered because of the reduced sales to Noranda resulting from the ice storm.[77]

7. On November 26, 2013, the Commission issued a Report and Order granting Ameren Missouri the AAO it sought.[78] Public Counsel and MIEC appealed that decision to the Western District Court of Appeals. On January 13, 2015, the court issued a *per curium* order that affirmed the Commission.[79] An application for transfer to the Missouri Supreme Court was denied on April 28, 2015.

8. In its Report and Order granting the requested AAO, the Commission found that revenue not collected by a utility to recover its fixed costs could be an item to be deferred and considered for later ratemaking treatment. It also determined that Ameren Missouri's loss of $35,561,503, which constitutes 8.5 percent of its net income in that year, is extraordinary and material. However, the report and order merely grants the AAO to permit Ameren Missouri to defer the costs for consideration in a future rate case. It does not make any finding or decision that would indicate the costs will ultimately be recovered in rates. Indeed, the report and order specifically says that "deferred recording does not guarantee recovery in any later rate action; recovery may be granted in whole, partially, or not at all."[80]

9. Between the time the deferred costs were incurred by Ameren Missouri and

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[77] Barnes Rebuttal, Ex. 3, Page 61, Lines 12-15.

[78] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

[79] The Court's Order is attached to Barnes Rebuttal, Ex. 3, Schedule LMB-R9.

[80] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

the present, the Commission has adjusted Ameren Missouri's rates in several rate cases.[81]

10. For the period between June 2007, through September 2014, Ameren Missouri has reported positive earnings.[82]

Conclusions of Law:

A. The fact that an AAO has been granted to defer these costs for consideration in this rate case does not mean Ameren Missouri is entitled to recover those costs. The granting of an AAO is not ratemaking and creates no expectation of recovery.[83] In discussing that expectation of recovery, the Missouri Court of Appeals has said:

> The whole idea of AAOs is to defer a final decision on current extraordinary costs until a rate case is in order. At the rate case, the utility is allowed to make a case that the deferred costs should be included, but again there is no authority for the proposition put forth here that the PSC is bound by the AAO terms.[84]

B. The Commission's decision to grant the AAO is not based on the same standard it now must use to determine whether those costs should be recovered. In granting the AAO, the Commission only determined that uncollected revenue was an item that could be deferred under accounting standards and that Ameren Missouri's loss was extraordinary and material.[85] But now, in this rate case, the Commission must consider "all relevant factors," otherwise it would be engaging in impermissible single-issue

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[81] File Nos. ER-2010-0036 and ER-2012-0166

[82] Meyer Direct, Ex. 513, Page 16, Lines 12-13.

[83] *State ex rel. Missouri Gas Energy v. Public Serv. Com'n*, 210 S.W.3d 330 (Mo. App. W.D. 2006)

[84] *Missouri Gas Energy v. Public Serv. Com'n*, 978 S.W.2d 434, 438 (Mo. App. W.D. 1998).

[85] *In the Matter of the Application of Union Electric Company d/b/a Ameren Missouri for the Issuance of an Accounting Authority Order Relating to its Electrical Operations*, Report and Order, File No. EU-2012-0027, November 26, 2013.

ratemaking.[86]

C. Staff, Public Counsel, and MIEC argue that Ameren Missouri's attempt to recover what it calls unrecovered fixed costs and what the opposing parties call unrecovered revenues or lost profit, constitutes an attempt at forbidden retroactive ratemaking. In arguing that recovery should not be allowed, the opposing parties point to a decision of the Missouri Supreme Court in *State ex rel. Utility Consumers Council of Missouri, Inc.,*[87] a decision that is frequently referred to as simply "*UCCM*" .

D. In *UCCM*, the Supreme Court struck down a Commission decision that allowed electric utilities to implement a fuel adjustment clause without supporting statutory authority. Having declared that the fuel adjustment clause was impermissible, the Supreme Court considered the legality allowing the electric utilities to collect a surcharge from customers to recover fuel costs from ratepayers for a period between the time an earlier fuel adjustment clause expired and before the challenged FAC went into effect. In refusing to allow the utilities to keep the money collected under the surcharge, the Court said:

> The utilities take the risk that rates filed by them will be inadequate or excessive, each time they seek rate approval. To permit them to collect additional amounts simply because they had additional past expenses not covered by either clause is retroactive rate making, i.e. the setting of rates which permit a utility to recover past losses or which require it to refund past excess profits collected under a rate that did not perfectly match expenses plus rate-of-return with the rate actually established.[88]

The Court then went on to find that the surcharge allowed the utilities to collect monies not collectible under the rate filed at the time the expenses were incurred, and the utilities had

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[86] *State ex rel. Missouri Gas Energy v. Public Serv. Com'n*, 210 S.W.3d 330 (Mo. App. W.D. 2006)

[87] 585 S.W.2d 41 (Mo banc 1979).

[88] *State ex rel. Utility Consumers Council of Missouri, Inc. v. Pub. Serv. Com'n*, 585 S.W.2d 41, 59, (Mo banc 1979).

no vested right to keep the money.

E. Although the quoted language from *UCCM* is quite broad, the Court's actual holding is more narrow. In fact, earlier in its discussion of those costs, the Supreme Court hints that if the expenses in question had been "'current' expenses reasonably anticipated and intended under the old clause, to be recovered at some point and were simply uncollected 'revenues'", they might have been recoverable.[89]

F. Certainly, in subsequent appellate decisions, the Court of Appeals has been open to the idea of allowing deferred costs to be recovered through a subsequent rate case. For example, in a 1998 case concerning legality of the Purchase Gas Adjustment (PGA) established in the tariffs of Missouri's natural gas distribution companies, the Court of Appeals held that the PGA was not improper retroactive ratemaking of the sort disapproved by the Supreme Court in *UCCM* because the rate adjustments made under the PGA are applied only to future customers on future bills.[90]

G. Similarly, in considering an appeal of an earlier Ameren Missouri rate case, the Court of Appeals held that the future amortized recovery of costs deferred under the vegetation management tracker did not constitute retroactive rate making.[91]

Decision:

As explained in its Conclusions of Law, the Commission must now evaluate all relevant factors to determine whether it is appropriate to allow Ameren Missouri to

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[89] *State ex rel. Utility Consumers Council of Missouri, Inc. v. Pub. Serv. Com'n*, 585 S.W.2d 41, 59, (Mo banc 1979).

[90] *State ex rel. Midwest Gas Users' Ass'n v. Pub. Serv. Com'n*, 976 S.W.2d 470, 481 (Mo. App. W.D. 1998).

[91] *State ex rel. Noranda Aluminum, Inc. v. Pub. Serv. Com'n* 356 S.W.3d 293, 319 (Mo. App. S.D. 2011).

recover the deferred unrecovered fixed costs in the rates that will be established in this case.

Ameren Missouri faced this problem of uncollected revenues because of the fuel adjustment clause through which it sought to reduce its risk from increasing net energy costs. If the fuel adjustment clause had not been in place following the 2009 ice storm and the resulting disruption to Noranda's production, Ameren Missouri could have recovered its fixed costs by the means it originally attempted, by selling the additional available power off-system. Unfortunately for the company, the fuel adjustment clause operated, as intended, and swept up 95 percent of those sales to be netted against rising energy costs, thereby reducing any cost recovery that would have occurred through the fuel adjustment clause. Thus, the fuel adjustment clause, from which the company expected to benefit, instead worked to the benefit of ratepayers.

Ameren Missouri did not foresee that result when the fuel adjustment clause was approved, but it is neither unjust nor unreasonable. When Ameren Missouri chose to provide service to a customer the size of Noranda, it understood that the profits it could earn from the business relationship came with a substantial risk. The risk that Noranda's production would fall and that it would be unable to sell as much electricity as it anticipated was a risk the company's shareholders, who benefit from the profits earned by serving Noranda, should bear. Ratepayers are not the insurers of Ameren Missouri's profits and should not have to bear the risk that those profits are not as great as anticipated because of a drop in production at Noranda. To now alter the consequences of that drop in production would be to retroactively change the allocation of risk approved by the Commission for the fuel adjustment clause that was in effect at the time.

In addition to this concern, the AAO granting deferral of these costs is unique in that Ameren Missouri has pursued and been granted a rate increase between this case and the losses at issue in this AAO. In that rate case, all relevant factors were considered, and rates for the future were set based on a period of time. It is not preferable to set rates in this case based on losses that are separated from the current test year by a number of years and by an intervening rate case.

Finally, Ameren Missouri experienced more than sufficient earnings to cover its fixed costs during all time periods between the ice storm and this rate case. While not a determinative factor alone in deciding whether to grant recovery of any AAO, this is one of the relevant factors the Commission must consider in setting just and reasonable rates in this case.

After considering all relevant factors, the Commission decides that recovery of the amounts deferred under the previously established accounting authority order is not appropriate.

6. Storm Expense and Two-Way Storm Costs Tracker

A. Should the Commission continue a two-way storm restoration cost tracker whereby storm-related non-labor operations and maintenance ("O&M") expenses for major storms would be tracked against the base amount with expenditures below the base creating a regulatory liability and expenditures above the base creating a regulatory asset, in each case along with interest at the Company's AFUDC rate?

Findings of Fact:

1. In Ameren Missouri's last rate case, the Commission established a two-way tracker for recovery of major storm related non-labor operations and maintenance expenses that would be tracked around a base level. If costs exceeded the base level, Ameren Missouri would be allowed to defer them for future recovery. If costs fell below the base level, Ameren Missouri would return the difference to ratepayers in a future rate case.[92]

2. In establishing the major storm cost tracker in the last rate case, the Commission expressed general skepticism of proposed tracking mechanisms, and noted there is a legitimate concern that a tracker can reduce a company's incentive to aggressively control costs. At that time, the Commission believed that those concerns were outweighed by the benefits of the two-way tracker.[93]

3. Ameren Missouri contends the tracker has worked as anticipated and asks that it be continued in this case.[94] Staff, Public Counsel, and MIEC all oppose continuation of the tracker.

4. Standard ratemaking methods already exist apart from the tracker to address these non-labor operations and maintenance major storm costs without the need for a tracker. The standard practice is to establish an average amount of storm costs to be included in rates to cover the company's costs. If the actually incurred costs are less than that amount, the company gets to keep the difference. If the actually incurred costs are

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[92] Boateng Rebuttal, Ex. 205, Page 3, Lines 17-26.

[93] *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* File No. ER-2012-0166, Report and Order, December 12, 2012, Page 96, Finding of Fact 11.

[94] Wakeman Rebuttal, Ex. 46, Page 4, Lines 7-17.

more than that amount, the company is at risk of suffering a shortfall. But if an extraordinary storm event occurs between rate cases, the company can request an accounting authority order to defer those extraordinary costs for possible inclusion in rates in a subsequent rate case.[95]

5. Using this combination of methods, before the tracker was implemented, Ameren Missouri was able to recover every dollar of expenses incurred for storm restorations between April 1, 2007, and September 30, 2014.[96]

6. Major storm costs are only a small part of Ameren Missouri's overall costs. During the test year, Ameren Missouri experienced approximately $6.8 million of non-labor storm restoration costs in comparison to approximately $2.6 billion of total operating expenses. That means the storm restoration costs are only 0.0026 percent of the company's total operating expenses.[97]

7. None of the other investor-owned electric utilities in Missouri have a storm restoration cost tracker.[98]

8. By their nature, cost trackers tend to reduce a utility's incentive to aggressively control costs by ensuring that all costs will be recovered.[99] Under a tracker, such costs would be subject to a prudence review, but a prudence review cannot control costs as efficiently as a strong economic incentive. Ameren Missouri obviously cannot control when its service area may be hit by a major storm, but it has at least some control

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[95] Boateng Rebuttal, Ex. 205, Pages 4-5, Lines 12-22, 1-2.

[96] Boateng Rebuttal, Ex. 205, Page 8, Lines 11-13.

[97] Boateng Rebuttal, Ex. 205, Page 9, Lines 4-14.

[98] Boateng Rebuttal, Ex. 205, Page 10, Lines 19-23.

[99] Transcript, Page 853, Lines 9-12.

over how it spends money in response to such storms.[100]

9. Ameren Missouri indicates it will continue to provide prompt and efficient storm restoration services with or without a tracker,[101] and there have been no allegations that it has not provided good storm restoration services in the past. Nevertheless, good public policy still requires the extra incentive a utility faces without the protection of a tracker.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

Storm costs have been shown to be relatively small and predictable. An exception to traditional ratemaking is not necessary to recover those costs. The Commission finds that eliminating the major storms cost tracker is good public policy.

B. If the storm cost tracker is not continued, what annualized level of major storm costs should the Commission approve in this case?

Findings of Fact:

1. With the major storm cost tracker having been eliminated, the Commission must now determine the amount of anticipated costs to be included in Ameren Missouri's rates. All parties agree the amount of major storm costs to be included in rates is $4.6 million, which is based on a 60-month normalization of such costs.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

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[100] Robertson Surrebuttal, Ex. 408, Page 9, Lines 2-14. See also, Boateng Surrebuttal, Ex. 206, Page 5, Lines 6-23. .

[101] Transcript, Page 843, Lines 13-23.

Decision:

The Commission accepts the recommendation of the parties and will set the amount of major storm costs to be included in rates at $4.6 million.

C. Should an amount of major storm cost over-recovery by Ameren Missouri be included in Ameren Missouri's revenue requirement and, if so, over what period should it be amortized?

Findings of Fact:

1. During the test year, Ameren Missouri spent less on major storm restoration costs than the base amount that was included in the tracker. All parties agree the amount of over-recovery should be returned to ratepayers.

2. Public Counsel recommends the over-recovery be returned to ratepayers amortized over two years. Staff and Ameren Missouri recommend the over-recovery be amortized and returned over five years, which is the length of time generally used for such amortizations.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission finds that a five year amortization is appropriate as that is the length of time that has generally been used for storm expense amortizations.

7. Vegetation Management and Infrastructure Inspection Trackers

B. Should the vegetation management and infrastructure inspection trackers be continued?[102]

[102] For the sake of clarity, the Commission is addressing sub-issue B before sub-issue A.

Findings of Fact:

1. Ameren Missouri's vegetation management and infrastructure inspection expense is closely associated with two Commission rules. Following extensive storm related service outages in 2006, the Commission promulgated new rules designed to compel Missouri's electric utilities to do a better job of maintaining their electric distribution systems. Those rules, entitled Electrical Corporation Infrastructure Standards[103] and Electrical Corporation Vegetation Management Standards and Reporting Requirements,[104] became effective on June 30, 2008.

2. The rules establish specific standards requiring electric utilities to inspect and replace old and damaged infrastructure, such as poles and transformers. In addition, electric utilities are required to more aggressively trim tree branches and other vegetation that encroaches on transmission lines. In promulgating the stricter standards, the Commission anticipated utilities would have to spend more money to comply. Therefore, both rules include provisions that allow a utility the means to recover the extra costs it incurs to comply with the requirements of the rule.

3. In an earlier rate case, ER-2008-0318,[105] the Commission allowed Ameren Missouri to recover a set amount in its base rates for vegetation management and infrastructure inspection costs. However, since the rules were new, the Commission found that Ameren Missouri had too little experience to know how much it would need to spend to comply with the vegetation management and infrastructure inspection rules. Because of

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[103] Commission Rule 4 CSR 240-23.020.

[104] Commission Rule 4 CSR 240-23.030.

[105] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306 (2009).

that uncertainty, the Commission established a two-way tracking mechanism to allow Ameren Missouri to track its vegetation management and infrastructure costs.

4. The order required Ameren Missouri to track actual expenditures over and under the base level. In any year in which Ameren Missouri spent below that base level, a regulatory liability would be created. In any year in which Ameren Missouri's spending exceeded the base level, a regulatory asset would be created. The regulatory assets and liabilities would be netted against each other and would be considered in a future rate case. The tracking mechanism contained a 10 percent cap so if Ameren Missouri's expenditures exceeded the base level by more than 10 percent it could not defer those costs under the tracking mechanism, but would need to apply for an additional accounting authority order. The Commission's order indicated the tracking mechanism would operate until new rates were established in Ameren Missouri's next rate case.[106]

5. The Commission renewed the tracking mechanism in Ameren Missouri's next three rate cases, ER-2010-0036, ER-2011-0028, and ER-2012-0166, finding that Ameren Missouri's costs to comply with the vegetation management and infrastructure inspection rules were still uncertain, as the company had not yet completed a full four/six year vegetation management cycle on its entire system. But in each case, the Commission indicated it did not intend to make the tracker permanent.[107]

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[106] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 339 (2009).

[107] *In the Matter of Union Electric Company, d/b/a Ameren UE's Tariffs to Increase its Annual Revenues for Electric Service, Report and Order*, File No. ER-2010-0036, 19 Mo. P.S.C. 3d 376 (2010); *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* Report and Order, File No. ER-2011-0028, July 13, 2011; and *In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* Report and Order, File No. ER-2012-0166, December 12, 2012.

6. Ameren Missouri asks that the tracker be continued. Staff, Public Counsel, MIEC, and MECG contend the tracker is no longer necessary and urge the Commission to end it.

7. Ameren Missouri has been operating under the Commission's vegetation management and infrastructure inspection rules for over seven years and has completed its first four-year cycle for vegetation management work on urban circuits and its first six-year cycle of work on rural circuits under the requirements of the rules.[108]

8. Tracker mechanisms can be a useful regulatory tool in the correct circumstances, but they should be used sparingly because they can reduce the incentive of the utility to closely control its costs.[109]

Conclusions of Law:

A. Commission Rule 4 CSR 240-23.020 establishes standards requiring electrical corporations, including Ameren Missouri, to inspect its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.020(3)(A) establishes a four-year cycle for inspection of urban infrastructure and a six-year cycle for inspection of rural infrastructure.

B. Commission Rule 4 CSR 240-23.020(4) establishes a procedure by which an electric utility may recover expenses it incurs because of the rule. Specifically, that section states as follows:

> In the event an electrical corporation incurs expenses as a result of this rule in excess of the costs included in current rates, the corporation may submit a request to the commission for accounting authorization to defer recognition and possible recovery of these excess expenses until the effective date of rates resulting from its next general rate case, filed after the

[108] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 15-18.

[109] Robertson Direct, Ex. 406, Pages 20-21, Lines 22-18, 1-10.

> effective date of this rule, using a tracking mechanism to record the difference between the actually incurred expenses as a result of this rule and the amount included in the corporation's rates … In the event that such authorization is granted, the next general rate case must be filed no later than five (5) years after the effective date of this rule. …

Ameren Missouri points to the mention of a tracking mechanism in this regulation to argue that the regulation recognizes the appropriateness of a tracker for the recovery of these costs. However, when read in context, it is clear that the tracker mentioned in the rule is intended to deal with the uncertainty of the cost of compliance with the new rule. The Commission established a tracker for just that purpose, but now the costs are well known and the tracker is no longer needed.

C. Commission Rule 4 CSR 240-23.030 establishes standards requiring electrical corporations, including Ameren Missouri, to trim trees and otherwise manage the growth of vegetation around its transmission and distribution facilities as necessary to provide safe and adequate service to its customers. Specifically, 4 CSR 240-23.030(9) establishes a four-year cycle for vegetation management of urban infrastructure and a six-year cycle for vegetation management of rural infrastructure. The vegetation management rule also includes a provision that allows Ameren Missouri to ask the Commission for authority to accumulate and recover its cost of compliance in its next rate case.[110]

Decision:

From the time this tracker was created, the Commission has said that it would only be a temporary expedient, needed only until a sufficient cost history could develop to allow for the accurate determination of normalized costs. A sufficient cost history now exists and the need for the tracker is at an end. The Commission finds that the vegetation

[110] Commission Rule 4 CSR 240-23.030(10).

management and the infrastructure inspection tracker are discontinued.

A. What amount should be included in the revenue requirement for Vegetation Management and Infrastructure Inspection?

C. If the vegetation management and infrastructure inspection trackers are not continued, what annualized level of vegetation management and infrastructure inspection costs should the Commission approve in this case?

Findings of Fact:

1. With the tracker having been eliminated, the Commission now must carefully establish the amount that Ameren Missouri may recover in its base rates for its vegetation management and infrastructure inspection costs.

2. Ameren Missouri proposes that the base rate level for vegetation management costs be set at approximately $56 million, with the base rate level for infrastructure inspections costs set at approximately $6.4 million. Those numbers are the actual incurred amount of costs through the true-up period.[111]

3. Staff proposes to use a three-year average of expenses to set the base rate cost level for vegetation management at $54,504,662 and $5,827,267 for infrastructure inspections.[112]

4. MIEC proposed a vegetation management cost level of $54 million, with $5.8 million allowed for infrastructure inspections.[113]

5. Public Counsel proposes to use a 62-months average covering the period of February 2009, through March 2014, adjusted for the true-up figures through December 31, 2014, to set the base level at $53,114,501 for vegetation management. Public Counsel

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[111] Moore Surrebuttal, Ex. 32, Page 9, Lines 5-11.

[112] Hanneken Surrebuttal, Ex. 218, Page 9, Lines 8-12.

[113] Meyer Surrebuttal, Ex. 514, Page 20, Lines 8-11.

used a two-year average, adjusted for true-up figures to set the base level at $6,149,077 for infrastructure inspections.[114]

6. This is a chart of Ameren Missouri's annual vegetation management costs since 2008:

2008	$49.2 million
2009	$50.9 million
2010	$50.4 million
2011	$52.9 million
2012	$52.3 million
2013	$55.2 million[115]
2014	$56.0 million[116]

The chart shows some up and down variation from year to year, but it also shows a definite upward trend. An average of all years of cost as proposed by Public Counsel and MIEC would not be a good representation of future costs since it would not recognize the upward trend. On the other hand, Ameren Missouri's proposal to just use the updated test year amounts is also not reasonable because it fails to recognize that the costs do not increase in a straight line. Staff's three-year average recognizes both aspects of the cost trend and is the most reasonable.

7. In the first year that Ameren Missouri incurred infrastructure inspection costs, 2008, the Company incurred annual infrastructure inspection costs of $8,165,926. By the fourth year, 2011, those annual costs had dropped to $5,373,259. For the test year ending March 31, 2014, the costs were $5,924, 356. On that basis, Public Counsel recommended that the base cost be set at the average of the last two twelve-month periods ending March

[114] Robertson True-Up Direct, Ex. 413, Page 2, Lines 5-18.

[115] Meyer Direct Ex. 513, Page 18, Table 3.

[116] Moore Surrebuttal, Ex. 32, Page 9, Lines 5-11.

2013 and 2014.[117] In the update period those costs had risen to approximately $6.4 million.[118] In True-Up Direct testimony, Public Counsel updated its proposed amount to include the update period ending December 31, 2014. The two-year average, utilizing the twelve months ended December 2013 and 2014 is $6,149,077. Public Counsel recommends the infrastructure inspection amount included in base rates be set at that amount.[119]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

Decision:

The Commission establishes the base rate cost level for vegetation management at $54,504,662, which is the number recommended by Staff. The base rate cost level for infrastructure inspections is established at $6,149,077, the number recommended by Public Counsel. The Commission finds that the two-year average number recommended by Public Counsel appropriately captures the recent increases in costs while assuring that the increased expense numbers from the true-up period are not just an anomaly.

D. Should an amount of vegetation management and infrastructure inspection cost over-recovery by Ameren Missouri be included in Ameren Missouri's revenue requirement and, if so, over what period should they be amortized?

Findings of Fact:

1. Since the last rate case, the vegetation management half of the tracker resulted in a regulatory asset, meaning Ameren Missouri spent more for vegetation management than the base level established in the tracker. The infrastructure inspection

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[117] Robertson Surrebuttal, Ex. 408, Page 14, Lines 4-17.

[118] Moore Surrebuttal, Ex. 32, Page 9, Lines 8-11.

[119] Robertson True-Up Direct, Ex. 413, Page 2, Line 5-18.

half of the tracker resulted in a regulatory liability, meaning Ameren Missouri spent less than the base amount established in the tracker. Under the terms of the tracker the two items are to be netted against each other and the resulting amount recovered from or returned to ratepayers. In addition, some amounts from the tracker ordered to be amortized in previous rate cases remain uncollected.[120] Staff, Public Counsel, and Ameren Missouri propose to combine all three figures and amortize that amount to be collected from ratepayers.

2. According to Staff's calculations, including true-up data, the revised total amount to be amortized and collected from ratepayers is $1,539,810. Amortized over three years as Staff and Ameren Missouri propose, that amounts to an annual figure of $513,270.[121]

3. Public Counsel proposed that the net over/under recovery amount be amortized over two years.[122]

4. The Commission has used a three-year amortization for tracked vegetation management and infrastructure inspection expenses in all previous Ameren Missouri rate cases in which the tracker was in place.[123]

5. MIEC opposes any collection of the regulatory asset resulting from under collections under the tracker because of its contention that Ameren Missouri over-earned during the period covered by the tracker.[124]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

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[120] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 4-31.

[121] Hanneken Surrebuttal, Ex. 218, Page 10, Lines 5-8.

[122] Robertson Direct, Ex. 406, Page 27, Lines 19-23.

[123] Staff Report Revenue Requirement, Ex. 202, Page 110, Lines 9-10.

[124] Meyer Direct, Ex. 513, Page 20, Lines 8-13.

Decision:

Staff has established the appropriate amount of the under-recovery in the existing tracker and the Commission finds that Staff's recommended amount shall be recovered from ratepayers amortized over three years.

8. Union Proposals

A. Can the Commission mandate or require that the Company address its workforce needs in a particular manner and, if so, should it do so?

Findings of Fact:

1. This issue is raised by the International Brotherhood of Electrical Workers Local 1439, AFL-CIO. That local represents 703 members who work for Ameren Missouri. Local 1439 does not represent all unionized Ameren Missouri employees; some are represented by other locals or other unions.[125] For convenience, this report and order will refer to Local 1439 simply as the "Union."

2. The Union affirms that Ameren Missouri has been providing its customers with "consistently reliable and inexpensive power for decades."[126] But it is concerned about what it describes as an aging workforce and an aging infrastructure.

3. To address the aging workforce problem, to replace current employees who are moving toward retirement, the Union asks the Commission to allocate an extra $11.1 million to Ameren Missouri and require the company to use that extra money to induct a class of at least 37 apprentices in various job categories in 2015 and for the next two successive years. Further, the Union asks the Commission to demand that Ameren Missouri fill all jobs, internal or outsourced, first within its service territory, second in

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[125] Walter Direct, Ex. 800, Page 2, Lines 1-17.

[126] Walter Direct, Ex. 800, Page 3, Lines 29-30.

Missouri, and never offshore[127]

4. The Union also expresses concern that Ameren Missouri is using too much contract labor rather than hiring additional internal workers because it believes the quality of the work provided by its members is superior to that provided by contract employees.[128] The Union's witness conceded there was no way to quantify that belief.[129]

5. Ameren Missouri has decreased the number of internal employees in recent years to improve efficiency and reduce costs.[130] But the company has completed all mandatory and scheduled maintenance work.[131] There is no evidence to suggest these reductions have prevented the company from offering safe and adequate service to its customers.

6. Ameren Missouri uses some contract labor to ensure efficient and effective completion of its work, particularly to meet short-term needs.[132] The company uses contract labor to do special projects that temporarily require a larger workforce. It would not be cost-effective to hire permanent employees to do that work if they would have to be laid-off when the special project was finished.[133]

7. Ameren Missouri is already planning to hire all the internal apprentices it believes it needs, and it does not want a special allocation for that purpose.[134]

8. The Union asks the Commission to address the aging infrastructure problem

[127] Walter Direct, Ex. 800, Page 9, Lines 16-23.

[128] Transcript, Pages 1040-1041, Lines 6-25, 1-11, and Ex. 801.

[129] Transcript, Page 1041, Lines 12-15.

[130] Wakeman Rebuttal, Ex. 46, Page 12, Lines 8-22.

[131] Wakeman Rebuttal, Ex. 46, Page 13, Lines 5-9.

[132] Wakeman Rebuttal, Ex. 46, Page 13, Lines 11-15.

[133] Transcript Pages 987-988, Lines 25, 1-23.

[134] Transcript, Pages 1015-1016, Lines 16-25, 1-10.

by giving the company an undefined special annual rate allocation in an undefined amount to allow the company to address its infrastructure needs.[135]

9. The Union's witness did not suggest any particular way the Commission might help Ameren Missouri meet its infrastructure needs, but in its brief, the Union suggested the Commission create a pool of money to allow the company to quickly be reimbursed for infrastructure expenditures or create an infrastructure system replacement surcharge such as authorized for other Missouri utilities.[136]

Conclusions of Law:

A. Section 393.130.1, RSMo (Cum. Supp. 2013), requires every electrical corporation, including Ameren Missouri, to "furnish and provide such service instrumentalities and facilities as shall be safe and adequate and in all respects just and reasonable."

B. Section 393.140.(1) gives this Commission general supervisory authority over all electrical corporations, again including Ameren Missouri. Subsection (2) of that statute authorizes the Commission to examine or investigate the operations of such utilities and to:

> order such reasonable improvements as will promote the public interest, preserve the public health and protect those using such … electricity …., and those employed in the manufacture and distribution thereof, and have power to order reasonable improvements and extensions of the works, wires, poles, pipes, lines, conduits, ducts and other reasonable devices, apparatus and property of … electrical corporations … .

Based on the authority given by that statute, the Commission may exercise a great deal of control over Ameren Missouri's operations.

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[135] Walter Direct, Ex. 800, Pages 9-10, Lines 31, 1-3.

[136] IBEW 1439's Post-Hearing Brief, Page 3, Fn. 1

C. But, while the Commission has authority to regulate Ameren Missouri to ensure the utility provides safe and adequate service, the Commission does not have authority to manage the company. In the words of the Missouri Court of Appeals;

> The powers of regulation delegated to the Commission are comprehensive and extend to every conceivable source of corporate malfeasance. Those powers do not, however, clothe the Commission with the general power of management incident to ownership. The utility retains the lawful right to manage its own affairs and conduct its business as it may choose, as long as it performs its legal duty, complies with lawful regulation, and does no harm to public welfare.[137]

Therefore, except as necessary to ensure the provision of safe and adequate service, the Commission does not have the authority to dictate to the company how many employees it must hire or whether it must use internal workforce rather than outside contractors to perform the work of the company.

D. The Commission's authority to assist Ameren Missouri in its efforts to direct capital expenditures toward aging infrastructure is also limited by statute. Section 393.135, RSMo 2000, prohibits the recovery in electric rates of the cost of construction work in progress or CWIP. That means Ameren Missouri cannot charge its customers to develop a fund to allow for quick recovery of the cost of unfinished capital projects. Similarly, the infrastructure system replacement surcharges that the Commission has established for water and gas utilities in Missouri are authorized by statute. No similar statutory authority exists for the creation of an ISRS for electric utilities.

Decision:

The evidence presented by the Union does not demonstrate that Ameren Missouri has failed to provide safe and adequate service. Therefore, the Commission will not

[137] *State ex rel. Harline v. Public Serv. Com'n*, 343 S.W.2d 177, 182 (Mo. App. 1960)

dictate to the company how many new employees it must hire, nor will it determine whether it must use its internal workforce or outside contractors to perform the company's work. Furthermore, there is no need for the Commission to direct Ameren Missouri to undertake any particular infrastructure replacement projects at this time.

B. Should the Commission require the additional reporting requested by Mr. Walters?

Findings of Fact:

1. The Union proposes that Ameren Missouri be required to provide additional quarterly reports to the Commission's Staff regarding its spending for infrastructure replacement and related to the special allocations proposed in the previous sub-issue.[138]

2. Ameren Missouri is ready to provide any information that Staff may request from it and believes that no additional reporting requirement is needed.[139]

Conclusions of Law:

The Commission makes no additional conclusions of law on this issue.

Decision:

The Commission finds there is no need to impose a new reporting requirement on Ameren Missouri as Staff can already obtain whatever information it needs from Ameren Missouri. Further, additional reporting requirements would ultimately increase costs for Ameren Missouri's ratepayers.

9. Return on Common Equity ("ROE")

In consideration of all relevant factors, what is the appropriate value for Return on Equity ("ROE") that the Commission should use in setting Ameren Missouri's Rate of Return?

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[138] Walter Direct, Ex. 800, Page 9, Lines 25-31.

[139] Transcript, Page 1015, Lines 7-15.

Findings of Fact:

1. This issue concerns the rate of return Ameren Missouri will be authorized to earn on its rate base. Rate base is the value of the utility's assets such as generating plants, electric meters, wires and poles, and the trucks driven by Ameren Missouri's repair crews. In order to determine a rate of return, the Commission must determine Ameren Missouri's cost of obtaining the capital it needs.

2. The relative mixture of sources Ameren Missouri uses to obtain the capital it needs is its capital structure. Ameren Missouri's actual capital structure as of the true-up date, December 31, 2014 is:

Long-Term Debt	47.18%
Short-Term Debt	00.00%
Preferred Stock	01.07%
Common Equity	51.76%[140]

No party has raised an issue regarding capital structure, so the Commission will not further address this matter.

3. Similarly, no party has raised an issue regarding Ameren Missouri's calculation of the cost of its long-term debt and preferred stock.

4. Determining an appropriate return on equity is the most difficult part of determining a rate of return. The cost of long-term debt and the cost of preferred stock are relatively easy to determine because their rate of return is specified within the instruments that create them. In contrast, to determine a return on equity, the Commission must consider the expectations and requirements of investors when they choose to invest their money in Ameren Missouri rather than in some other investment opportunity. As a result, the Commission cannot simply find a rate of return on equity that is unassailably

[140] Murray Surrebuttal, Ex. 228, Page 4, Line 12.

scientifically, mathematically, or legally correct. Such a "correct" rate does not exist. Instead, the Commission must use its judgment to establish a rate of return on equity attractive enough to investors to allow the utility to fairly compete for the investors' dollar in the capital market without permitting an excessive rate of return on equity that would drive up rates for Ameren Missouri's ratepayers. To obtain guidance about the appropriate rate of return on equity, the Commission considers the testimony of expert witnesses.

5. Four financial analysts offered recommendations regarding an appropriate return on equity in this case. Robert B. Hevert testified on behalf of Ameren Missouri. Hevert is Managing Partner of Sussex Economic Advisors, LLC. He holds a Bachelor of Science degree in Finance from the University of Delaware and a Master of Business Administration with a concentration in finance from the University of Massachusetts.[141] He recommends the Commission allow Ameren Missouri a return on equity of 10.4 percent, within a range of 10.2 percent to 10.6 percent.[142]

6. Michael Gorman testified on behalf of MIEC. Gorman is a consultant in the field of public utility regulation and is a managing principal of Brubaker & Associates.[143] He holds a Bachelor of Science degree in Electrical Engineering from Southern Illinois University and a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield.[144] Gorman recommends the

[141] Hevert Direct, Ex. 16, Page 1, Lines 5-16.

[142] Hevert Direct, Ex. 16, Page 2, Lines 16-21.

[143] Gorman Direct, Ex. 510, Page 1, Lines 4-6.

[144] Gorman Direct, Ex. 510, Appendix A, Page 1, Lines 9-12.

Commission allow Ameren Missouri a return on equity of 9.30 percent, within a recommended range of 9.00 percent to 9.60 percent.[145]

7. Lance Schafer testified on behalf of the Public Counsel. Schafer is employed by the Office of the Public Counsel as a Public Utility Financial Analyst. He holds a Bachelor of Arts in English from the University of Missouri, Columbia; a Master of Arts in French from the University of California, Irvine; and a Master of Business Administration with a specialization in Finance from the University of Missouri, Columbia.[146]

8. Finally, David Murray testified on behalf of Staff. Murray is the Utility Regulatory Manager of the Financial Analysis Unit for the Commission. He holds a Bachelor of Science degree in Business Administration from the University of Missouri – Columbia, and a Masters degree in Business Administration from Lincoln University. Murray has been employed by the Commission since 2000 and has offered testimony in many cases before the Commission.[147] Murray recommends a return on equity of 9.25 percent, within a range of 9.00 percent to 9.50 percent.[148]

9. A utility's cost of common equity is the return investors require on an investment in that company. Investors expect to achieve their return by receiving dividends and through stock price appreciation.[149] To comply with standards established by the United States Supreme Court, the Commission must authorize a return on equity sufficient

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[145] Gorman Direct, Ex. 510, Page 2, Lines 4-9.

[146] Schafer Direct, Ex. 409, Page 1, Lines 11-15.

[147] Staff Report Revenue Requirement Cost of Service, Ex. 202, Appendix 1, Page 61.

[148] Staff Report Revenue Requirement Cost of Service, Ex. 202, Page 11, Lines 1-11.

[149] Gorman Direct, Ex. 510, Page 11, Lines 17-19.

to maintain financial integrity, attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk.[150]

10. Financial analysts use variations on three generally accepted methods to estimate a company's fair rate of return on equity. The Discounted Cash Flow (DCF) method is based on a theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows.[151] The analysts also use variations of the DCF model including the multi-stage growth DCF[152] and the sustainable growth DCF[153] The Risk Premium method assumes that the investor's required return on an equity investment is equal to the interest rate on a long-term bond plus an additional equity risk premium needed to compensate the investor for the additional risk of investing in equities compared to bonds.[154] The Capital Asset Pricing Method (CAPM) assumes the investor's required rate of return on equity is equal to a risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.[155] No one method is any more "correct" than any other method in all circumstances. Analysts balance their use of all three methods to reach a recommended return on equity.

11. Before examining the analyst's use of these various methods to arrive at a recommended return on equity, it is important to look at some other numbers. For 2014,

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[150] Gorman Direct, Ex. 510, Page 12, Lines 1-11.

[151] Hevert Direct, Ex. 16, Page 14, Lines 5-8.

[152] Hevert Direct, Ex. 16, Page 19, Lines 7-14.

[153] Gorman Direct, Ex. 510, Pages 19-20

[154] Hevert Direct, Ex. 16, Page 28, Lines 4-14.

[155] Gorman Direct, Ex. 510, Pages 32-33, Lines 13-24, 1-13.

the average return on equity awarded to all electric utilities by state commissions in this country was 9.76 percent. For fully litigated rate cases, the average number dropped to 9.63 percent. But those numbers include distribution only companies in deregulated states. Excluding those companies and looking only at vertically integrated electric companies like Ameren Missouri, the average return on equity award in 2014 was 9.94 percent. Looking only at returns established in fully litigated rate cases, that average was 9.86 percent.[156]

12. The Commission mentions the average allowed return on equity because Ameren Missouri must compete with other utilities all over the country for the same capital. Therefore, the average allowed return on equity provides a reasonableness test for the recommendations offered by the return on equity experts.

13. In its decision regarding Ameren Missouri's last rate case, the Commission established an ROE of 9.8 percent.[157] Since 2012, when that case was decided, interest rates have declined by approximately 37 basis points.[158] Furthermore, utility stock prices have increased and their dividend yields have gone down. This indicates that utilities' cost of capital has decreased because they need to sell fewer shares to generate the capital they need to support their investments.[159] As MIEC's witness, Michael Gorman, explained: "Because the price of stock has gone up and the other parameters of the stock have not significantly changed, that's a clear indication that investors have reduced their required

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[156] Gorman Surrebuttal, Ex. 512, Schedule MPG-SR-1.

[157] *In the Matter of Union Electric Company, d/b/a/ Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service,* File No. ER-2012-0166, Report and Order, December 12, 2012.

[158] Gorman Surrebuttal, Ex. 512, Page 7, Lines 1-2.

[159] Gorman Surrebuttal, Ex. 512, Page 7, Lines 7-10.

cost of capital which has bid up the stock price."[160] This suggests the ROE allowed to Ameren Missouri should also be decreased.

14. Similarly, Staff's witness, David Murray, believes that investor expectations for ROE have declined so that today investors would reasonably expect an ROE of 9.5 percent.[161]

15. Ameren Missouri's expert witness, Robert Hevert, supports an increased ROE at 10.4 percent. The Commission finds that such an ROE would be excessive. In large part, Hevert's ROE estimate is high because he based his multi-stage DCF analysis calculations on an optimistic nominal long-term GDP growth rate outlook of 5.71 percent.[162] As Gorman explains, that growth rate is substantially higher than consensus economists' forward-looking real GDP growth outlooks.[163] Adjusting Hevert's optimistic growth rate outlook to the consensus economist level reduces his multi-stage growth DCF return from 10.02 percent to 8.80 percent for his proxy group.[164]

16. Similarly, if Hevert's CAPM analysis is adjusted to use more reasonable projected returns on the market, that analysis would result in a range of 8.80 percent to 9.52 percent.[165]

17. Gorman, a reliable rate of return expert, recommends the Commission set ROE in a range between 9.0 percent and 9.6 percent. He recommended that the rate be set at the mid-point of that range, which is 9.3 percent, but he indicated that any rate within

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[160] Transcript, Page 1269, Lines 6-10.

[161] Transcript, Page 1358, Lines 9-14.

[162] Hevert, Direct, Ex. 16, Pages 22-23, Lines 3-9, 1-10.

[163] Gorman Rebuttal, Ex. 511, Page 8, Lines 1-7.

[164] Gorman Rebuttal, Ex. 511, Page 10, Lines 10-13.

[165] Gorman Rebuttal, Ex. 511, Page 13, Lines 8-14.

his range would be reasonable and would be adequate to attract capital at reasonable terms, would be sufficient to ensure the company's financial integrity, and is commensurate with returns on investment in enterprises having corresponding risks.[166]

18. Public Counsel's witness, Lance Schafer, recommended an ROE of 9.01 percent, within a range of 8.74 percent to 9.22 percent. Aside from any technical criticism about Schafer's methodology, an ROE of 9.01 is too low because it is substantially below the average ROE awarded by other state commissions to similarly situated utilities. Obviously, this Commission is not bound to follow the lead of other commissions in setting an appropriate ROE. In fact, the ROE the Commission has found to be reasonable in this case is below the average. But the capital market in which Ameren Missouri must compete is competitive. An ROE set 80 to 100 basis point below the ROE set for similar electric utilities could limit the company's ability to attract capital and could violate the *Hope* and *Bluefield* standard described earlier in this order, which requires that rates be set at a level that will allow the utility a return on its investment comparable to that earned by other companies with "corresponding risks and uncertainties."[167]

Conclusions of Law:

A. In assessing the Commission's ability to use different methodologies to determine just and reasonable rates, the Missouri Court of Appeals has said:

> Because ratemaking is not an exact science, the utilization of different formulas is sometimes necessary. … The Supreme Court of Arkansas, in dealing with this issue, stated that there is no 'judicial mandate requiring the Commission to take the same approach to every rate application or even to consecutive applications by the same utility, when the commission in its expertise, determines that its previous methods are unsound or inappropriate

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[166] Transcript, Page 1197, Lines 9-23.

[167] *Bluefield Water Works & Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 692 (1923).

> to the particular application' (quoting Southwestern Bell Telephone Company v. Arkansas Public Service Commission, 593 S.W. 2d 434 (Ark 1980).[168]

Furthermore,

> Not only can the Commission select its methodology in determining rates and make pragmatic adjustments called for by particular circumstances, but it also may adopt or reject any or all of any witnesses' testimony.[169]

B. In another case, the Court of Appeals recognized that the establishment of an appropriate rate of return is not a "precise science":

> While rate of return is the result of a straight forward mathematic calculation, the inputs, particularly regarding the cost of common equity, are not a matter of 'precise science,' because inferences must be made about the cost of equity, which involves an estimation of investor expectations. In other words, some amount of speculation is inherent in any ratemaking decision to the extent that it is based on capital structure, because such decisions are forward-looking and rely, in part, on the accuracy of financial and market forecasts.[170]

Decision:

Based on the competent and substantial evidence in the record, on its analysis of the expert testimony offered by the parties, and on its balancing of the interests of the company's ratepayers and shareholders, as fully explained in its findings of fact and conclusions of law, the Commission finds that 9.53 percent is a fair and reasonable return on equity for Ameren Missouri. That rate is within expert witness Gorman's range, and only slightly above expert witness Murray's recommended range. The Commission finds that

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[168] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[169] *State ex rel. Assoc. Natural Gas Co. v. Public Service Commission,* 706 S.W. 2d 870, 880 (Mo. App. W.D. 1985).

[170] *State ex rel. Missouri Gas Energy v. Public Service Commission*, 186 S.W.3d 376, 383 (Mo App. W.D. 2005).

this rate of return will allow Ameren Missouri to compete in the capital market for the funds needed to maintain its financial health.

10. Class Cost of Service, Revenue Allocation and Rate Design

A. What methodology should the Commission use to allocate generation fixed costs among customer classes?

B. How should the non-fuel, non-labor components of production, operation and maintenance expense be classified and allocated?

G. What methodology should the Commission use to allocate off-system sales revenues among customer classes?

I. *What methodology should the Commission use to allocate fuel and purchased power costs among customer classes?*

H. What methodology should the Commission use to allocate income tax expense among customer classes?

Findings of Fact:

1. After the Commission determines the amount of rate increase that is necessary, it must decide how that rate increase will be spread among Ameren Missouri's customer classes. The basic principle guiding that decision is that the customer class that causes a cost should pay that cost.

2. The Class Cost of Service and Rate Design issue is similar to the ROE issue in that the method used to arrive at a number is less important than the reasonableness of the final number. Ameren Missouri, Staff, MIEC, and Public Counsel performed class cost of service studies using different methods with some different inputs. Each study is designed to measure how much each of the different rate classes contributes to Ameren Missouri's total cost of service. Rates should then be set so that each rate class contributes enough revenue to pay its fair share of those costs. But the class cost of service studies should not be taken as a precise mathematical calculation of correct

rates.[171] Rather, the Commission must use its judgment to set just and reasonable rates for the various rate classes.

3. Ameren Missouri's and MIEC's experts use an Average and Excess (A&E) four non-coincident peak production allocator methodology. That methodology conceptually splits the electric system into an average component and an excess component. The average component is the amount of capacity needed to produce the required energy if it were taken at the same demand rate each hour. The excess component measures the difference between average demand and peak demand at four non-coincident peaks.[172] The Commission has accepted the reasonableness of this methodology in past Ameren Missouri rate cases.

4. Staff's expert relied on several Base, Intermediate and Peak (BIP) class cost of service studies. As the name implies, the BIP studies attempt to divide class contributions to costs into three categories rather than the two used in the A&E methods. Despite the conceptual differences, Staff's BIP studies reach the same general conclusions as the A&E methods used by Ameren Missouri's and MIEC's experts.[173]

5. The one outlier method is the Peak and Average (P&A) methodology used as an alternative method by Public Counsel. The Commission has rejected the P&A methodology in past rate cases and Public Counsel offered an alternative A&E study in recognition of that previous rejection.[174]

6. The weakness with the P&A methodology is that after dividing the average

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[171] Transcript, Page 3022, Lines 2-25.

[172] Brubaker Direct, Ex. 503, Pages 25-26, Lines 16-22, 1-7. See also, Davis Direct, Ex. 7.

[173] Staff Report Rate Design, Ex. 201, Page 8, Lines 3-9.

[174] Marke Direct, Ex. 403, Page 26, Lines 7-13.

and excess components, instead of allocating just the excess average demand to the cost-causing classes, it allocates the entire peak demand to the various classes. That has the effect of double counting the average demand and allocates more costs to large industrials that have a steady but high average demand that does not contribute as much to the system peaks. That method works to the benefit of the residential class whose usage varies more by time of day and time of year.[175]

7. Public Counsel does not propose to adjust rates for the classes based specifically on its P&A study, instead supporting the joint position described in the objected-to non-unanimous stipulation and agreement that all rate classes should be given the same percentage increase.[176]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission will once again reject Public Counsel's P&A study because it has the effect of double counting average demand. Also, because the results of the A&E and BIP studies are similar, the Commission does not need to decide which particular study is most appropriate. Therefore, all the specific sub-issues involving the difference between those studies are moot and do not need to be addressed in this case. The Commission will need to decide whether inter-class rates should be adjusted based on those studies.

C. How should any rate increase be collected from the several customer classes?

Findings of Fact:

1. All of the A&E and BIP class cost of service studies indicate the residential

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[175] Brubaker Rebuttal, Ex. 504, Page 6, Lines 1-21.

[176] Post-Hearing Brief of the Office of the Public Counsel, Page 39.

and large transmission service (Noranda) classes are currently providing below average returns. That means those classes should contribute a greater share of Ameren Missouri's revenues than they currently are if they are to match their class cost of service. All studies also show that the small general service, large general service and small primary service are providing above average returns. That means they are currently contributing a greater share of revenue than would be indicated by their class cost of service. The other rate classes contribute revenues close to their cost of service.[177]

2. Ameren Missouri, Public Counsel, MIEC, and all other signatories to the objected-to Noranda special rate stipulation and agreement suggest that no adjustments be made to the class contributions. Instead, they would apply any increases ordered in this case "across the board", in other words, equally to all the customer classes.

3. Staff, MECG, and Wal-Mart would make some adjustments to bring the classes closer to their cost of service. Staff proposes a six-step process to bring the rate classes closer to their cost of service: 1) the Residential and LTS classes would receive a positive .50% revenue neutral adjustment, meaning their rates would increase 0.50% even before any rate increase that would result from this case. The small general service, large general service and small primary service would receive a negative 0.63% revenue neutral adjustment. 2) The portion of the revenue increase or decrease that is attributable to the amortization of the energy efficiency programs from the pre-MEEIA program costs would be assigned directly to the applicable customer classes. 3) The amount of revenue increase awarded to Ameren Missouri that is not associated with step 2 would be determined. 4) Ameren Missouri's rate schedules would be made uniform for certain interrelationships

[177] For example, *see*, Warwick Direct, Ex. 49, Sch. WMW-1.

among the non-residential rate schedules that are integral to Ameren Missouri's rate design. 5) The residential customer charge would remain at $8.00. 6) After steps 1-5 are accomplished, any additional rate increase would apply across the board to all rate classes.[178]

4. MECG and Wal-Mart are particularly concerned about the large general service and small primary service classes. They presented evidence to show that the over-recovery from those classes has been long-standing, going back to the 2007 rate case.[179] To move toward actual cost of service, they ask the Commission to apply a 25% revenue neutral movement toward cost of service, while ensuring that no class receive a rate increase greater than 9.65%.[180]

5. Ameren Missouri has indicated that, aside from leaving the customer charge at $8.00, Staff's proposal is reasonable and would be acceptable. It also indicates that Wal-Mart's rate design proposal is reasonable.[181]

6. The small general service, large general service and small primary service rate classes have received negative rate adjustments in past Ameren Missouri rate cases, meaning the Commission has acted to move those classes closer to their cost of service. In ER-2010-0036, that negative adjustment was 0.61 percent, in ER-2011-0028 it was 1.78 percent, and in ER-2013-0166, it was 0.18 percent.[182]

7. The contribution collected from the various classes can change because of

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[178] Scheperle Direct, Ex. 232, Pages 3-4, Lines 17-21, 1-32.

[179] Chriss Cost of Service Direct, Ex. 751, Page 6, Tables 2 and 3.

[180] Chriss Cost of Service Direct, Ex. 751, Pages 9-10, Lines 18-22, 1-6.

[181] Transcript, Page 1494, Lines 2-11.

[182] Fortson Rebuttal, Ex. 215, Schedule BJF-R1.

factors other than Commission action to adjust rates.[183] For example, even though the residential rate class is currently above its cost of service, over time, because of energy savings and the way the allocations work, they will move closer to their cost of service without any rate adjustments by the Commission.[184]

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) states:

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

Decision:

The Commission agrees with Staff, MECG, and Wal-Mart that the existing class contributions to rates are out of balance. The only question is how much of an adjustment should be made to move the rate classes toward their cost of service as shown in the class cost of service studies. The Wal-Mart proposal would move the large general service and small primary service classes to their cost of service more quickly than Staff's proposal, but it would also have a greater impact on the classes that would see larger than average increases, notably the residential class. To minimize rate shock for the classes that will see larger than system average increases, while still moving closer toward actual cost of service, the Commission will adopt Staff's six step proposal.

D. What should the Residential Class customer charge be?

Findings of Fact:

1. The customer charge is the set amount on every customer's bill that must be

[183] Transcript, Page 3022, Lines 2-25.

[184] Transcript, Page 1497, Lines 1-7.

paid even if the customer uses no electricity.

2. Customer-related costs are the minimum costs necessary to make electric service available to the customer, regardless of how much electricity the customer uses. Examples include meter reading, billing, postage, customer account service, and a portion of the costs associated with required investment in a meter, the service line drop, and other billing costs.[185] Customer-related costs are generally recovered through the customer charge while other costs are recovered through volumetric rates that vary with the amount of electricity used.

3. It is important to remember that determining an appropriate customer charge is a question of rate design, not a question of the company's revenue requirement. That means any increase in the company's customer charge would be accompanied by a decrease in volumetric rates so that, in theory, the company recovers the same amount of revenue.

4. In actual practice, because the amount collected from volumetric rates varies with the amount of electricity used, the company will collect less money from volumetric rates when customers use less electricity. Thus, for example, in a cool summer, when customers are using less air conditioning, the company runs the risk of collecting less revenue. For that reason, electric utilities prefer to lessen risk by collecting more of their charges through the fixed customer charge.

5. Ameren Missouri's current customer charge for residential customers is set at $8.00 per month. Staff's class cost of service study would support recovery of a customer

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[185] Staff Report Rate Design, Ex. 201, Pages 43-44, Lines 29-31, 1-2.

charge of $8.11 but Staff recommends that the charge remain at $8.00.[186]

6. Ameren Missouri contends a customer charge of over $20 would be supported by the class cost of service studies,[187] but it only proposes to increase the residential customer charge by the same percentage as the overall rate increase that results from this case.[188] At Ameren Missouri's original rate increase that would have increased the customer charge to $8.77.[189] Since Ameren Missouri's requested increase is now lower, the customer charge increase request would be around $8.50. Since the Commission will not give Ameren Missouri the entire increase it has requested, the residential customer charge would be something less than $8.50 under Ameren Missouri's proposal.

7. Because no party is arguing that the customer charge should be based on the results of a particular class cost of service report, the Commission will not address the details of those reports. In any event, the Commission is not bound to set the customer charges based solely on the details of the cost of service studies. The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges.

8. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the

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[186] Staff Report Rate Design, Ex. 201, Page 43, Lines 26-28.

[187] Davis Rebuttal, Ex.9, Page 13, Line 1.

[188] Transcript, Page 1498, Lines 16-25.

[189] Davis Rebuttal, Ex. 9, Page 11, Lines 4-5.

monthly charge where it is gives the customer more control.

9. Since Ameren Missouri has not shown a strong reason to increase the customer charge and is seeking only a small, largely token increase, the Commission finds that the existing customer charges for the residential class should not be increased.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission finds that Ameren Missouri's customer charges for residential customers shall remain at $8.00.

E. Should the Commission approve Wal-Mart's proposed shift to increase the demand component of the hours-use rate design for Large General Service and Small Primary Service?

Findings of Fact:

1. This sub-issue concerns rate design only within the large general service and small primary service class. Wal-Mart looked at Ameren Missouri's class cost of service study and noted that approximately 66.1% of non-energy efficiency base revenues for that class are demand-related, while 31.7% are energy related. However, under the "hours-use" intra-class rate design structure used by Ameren Missouri, a large portion of the class' demand-related costs are collected through energy charges.[190]

2. The large general service and small primary service class currently uses a declining three-block "hours-use" rate structure. As usage moves up to the next block, the rate declines. The "hours-use" rate structure has the effect of shifting demand cost

[190] Chriss Cost of Service Direct, Ex. 751, Page 11, Lines 15-22.

responsibility from lower load factor customers to those with higher load factors.[191] Wal-Mart is a higher load factor customer and does not want to subsidize other customers within its rate class.[192]

3. Ameren Missouri would spread the increase resulting from this rate case equally among the three blocks. Wal-Mart proposes that the second and third block energy rates remain at their current levels and that the customer charge for the class be increased by the percentage of overall revenue increase. Half of the remaining overall increase would be applied to the first block energy charge and the other half to the demand charge.[193]

4. Wal-Mart's proposal would have a large and unfavorable impact on lower load factor customers, possibly resulting in double digit percentage increases for those customers, in addition to whatever rate increase results from this case. Meanwhile, the proposal would reduce rates for higher load customers by only a few percentage points.[194]

5. The "hours-use" rate design has been in use in Missouri since 1990 when the Commission approved its use as part of a settlement of a revenue complaint case and a rate design case.[195]

6. All the other investor-owned electric utilities in Missouri use an "hours-use"

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[191] Chriss Cost of Service Direct, Ex. 751, Page 12, Lines 1-14.

[192] Chriss Cost of Service Direct, Ex. 751, Page 13, Lines 1-7.

[193] Chriss Cost of Service Direct, Ex. 751, Page 17, Lines 14-20.

[194] Davis Rebuttal, Ex. 9, Page 9. Lines 4-15. *In the Matter of the Investigation of Union Electric Company's Class Allocation and Rate Design,* Report and Order, Case No. EO-87-175, 30 Mo. P.S.C. (N.S.) 406 (1990).

[195] Davis Rebuttal, Ex. 9, Pages 7-8, Lines 21-22, 1-10.

rate design for the non-residential customers.[196]

7. Staff recommends against accepting Wal-Mart's proposal because it believes more study is needed to assess the rate impact of the proposed changes on the 11,000 other customers in those rate classes.[197]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

Wal-Mart is proposing a change in a long-standing rate structure that could have significant rate impact on 11,000 customers. There is not enough evidence in the record for this case to justify making that change at this time. The Commission is willing to examine this question in more detail in Ameren Missouri's next rate case and expects the parties to more fully develop the evidence at that time. The Commission will not adopt Wal-Mart's proposal at this time.

F. Should the Commission approve Wal-Mart's recommendation to require the Company to present analyses of alternatives to the hours-use rate design in its next rate case?

Findings of Fact:

1. As discussed in the previous sub-issue, Wal-Mart is generally dissatisfied with the "hours-use" rate design used by Ameren Missouri and all other electric utilities in Missouri. It asks the Commission to order Ameren Missouri to develop alternative rate designs for the large general service and small primary class that more closely reflect the company's cost of service and do not use the hours-use rate design for the energy charge. It asks that Ameren Missouri be ordered to present those alternatives in

[196] Fortson Rebuttal, Ex. 215, Pages 7-8, Lines 16-17, 1-2.

[197] Fortson Rebuttal, Ex. 215, Page 7, Lines 12-15.

its next base rate case.[198]

2. Ameren Missouri indicates it is satisfied with the current “hours-use” rate design and asserts that if Wal-Mart wants to see a change it has the ability to perform and pay for its own cost study.[199]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

While the Commission is willing to look at this issue in the next rate case, it agrees that Wal-Mart has the resources to perform its own study and will not order Ameren Missouri to undertake the study proposed by Wal-Mart. Each party may perform its own study if it wishes to do so.

11. Economic Development Rate Design Mechanisms

A. Should the Commission expand the application of Ameren Missouri’s existing Economic Development Riders?

Findings of Fact:

1. On October 20, 2014, the Commission issued an order in this case that directed the parties to address questions about rate design mechanisms that could be used to promote stability or growth of customer levels in geographic locations where existing infrastructure is underutilized. That order directed Staff to file testimony on that question and invited other parties to also address the issue.[200]

2. The responses from the parties to that question raised questions about the

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[198] Chriss Cost of Service Direct, Ex. 751, Pages 17-18, Lines 20-21, 1-2.

[199] Initial Post-Hearing Brief of Ameren Missouri, Page 150.

[200] Order Directing Consideration of a Certain Rate Design Question, File No. ER-2014-0258, October 20, 2014

scope and effectiveness of Ameren Missouri's existing Economic Development Riders.

3. Staff's response to the Commission's questions described Ameren Missouri's existing economic development riders and provided additional ideas for new or expanded programs. Staff did not recommend the Commission take any action at this time but recommended the Commission form a collaborative to collect ideas for future action from all interested stakeholders.[201]

4. Public Counsel also filed testimony discussing Ameren Missouri's existing Economic Development Riders and suggesting ideas for new or expanded programs. In particular, Public Counsel compared Ameren Missouri's existing Riders to those currently offered by Kansas City Power & Light Company and The Empire District Electric Company.[202]

5. Ameren Missouri filed the supplemental direct testimony of William Davis in response to the Commission's order. Davis' testimony describes the company's existing Economic Re-Development Rider (ERR). That Rider has been in place since 2007 and is designed to encourage re-development of certain sites in the City of St. Louis. Eligibility for participation in the Rider is limited to industrial and large commercial rate classes.[203]

6. Staff and Public Counsel also describe a more general Ameren Missouri Rider known as the Economic Development and Retention Rider (EDRR).[204]

7. On March 9, several parties signed and filed a non-unanimous stipulation and agreement regarding class cost of service and rate design. The primary focus of the

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[201] Staff Report Rate Design, Ex. 201, Page 45, Lines 18-20.

[202] Marke Direct, Ex. 403, Pages 3-23.

[203] Davis Supplemental Direct, Ex. 8.

[204] Marke Direct, Ex. 403, Page 18, and Staff Report Rate Design, Ex. 201, Page 48.

stipulation and agreement was the provision of a reduced rate for Noranda. But it also included an exemplar economic development tariff for Ameren Missouri. That proposed tariff was never discussed when evidence was presented at the hearing, as it was filed five days after the issue was heard. As a result, there is no evidentiary support for it in the record.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission does not believe any action regarding Ameren Missouri's economic development riders is appropriate at this time. As will be noted subsequently in this order, the Commission will establish a collaborative to look at this issue more closely.

B. Should the Commission modify Ameren Missouri's existing Economic Development Riders to require recipients to participate in the Company's energy efficiency programs?

Findings of Fact:

1. The Division of Energy proposed that Ameren Missouri be directed to modify its existing economic development riders to require active participation in Ameren Missouri's MEEIA programs as a condition for participation in the riders.[205]

2. Ameren Missouri currently has two economic development riders in its tariffs. The Economic Re-Development Rider (ERR), which is designed to encourage re-development of certain sites in the City of St. Louis, and a more general Ameren Missouri Rider known as the Economic Development and Retention Rider (EDRR). Thus far only one customer has taken advantage of the EDRR.[206] No customers currently take service

[205] Lohraff Direct, Ex. 702, Page 2, Lines 10-13.

[206] Staff Report Rate Design, Ex. 201, Page 53, Lines 22-26.

under the ERR.[207]

3. MIEC, the party that represents many of the industrial-type customers who would be eligible to participate in the economic development riders opposed the idea of requiring participation in MEEIA as unnecessary and illegal.[208]

4. The other parties that responded to the request that participation in MEEIA be made a requirement to take service under an economic development rider raised questions and concerns about that proposal that can best be addressed through a collaborative process.[209]

Conclusions of Law:

A. The MEEIA statute, specifically section 393.1075.7, RSMo (Cum. Supp. 2013), allows certain large users of electricity to opt out of participation in MEEIA programs.

Decision:

Participation in Ameren Missouri's economic development riders is not robust at this time and adding criteria for participation will not encourage greater participation. The Commission will not make participation in MEEIA a requirement for receiving service through Ameren Missouri's economic development riders. As will be noted subsequently in this order, the Commission will establish a collaborative to look at this issue more closely.

C. Should the Commission open a docket to explore the role economic development riders have across regulated industries (i.e. water, electric, natural gas) and/or to further explore issues raised by parties in this case and issues the Commission

[207] Staff Report Rate Design, Ex. 201, Page 54, Lines 11-12.

[208] Brubaker Rebuttal, Ex. 504, Pages 25-26.

[209] *See,* Davis Rebuttal, Ex. 9, Pages 35-37.

inquired about at the beginning of the case?

Findings of Fact:

1. Staff suggested the Commission open a collaborative to allow all interested stakeholders to discuss possible changes to Ameren Missouri's existing economic development riders.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The Commission will establish a collaborative process to more closely examine the use of economic development riders. The Commission will open a new working case for that purpose, and the parameters of that collaborative will be established in an order that will be issued in that new case.

12. Street Lighting

A. Can the Commission mandate or require that the Company sell its streetlights to the Cities?

Findings of Fact:

1. Ameren Missouri offers electricity to power municipal streetlights under two different provisions of its tariff. Under rate schedule 5(M), the municipal customer pays for the electricity needed to power the lights, but Ameren Missouri installs, owns and maintains the light fixtures, poles, wires, and other connections needed to provide street lighting. Ameren Missouri recovers those costs through the rate it charges the customer. Under the alternative 6(M) rate schedule, the municipal customer installs, owns, and maintains the light fixtures, poles, wires, and other connections, and pays a rate sufficient to recover the

cost of the electricity needed to power the lights.[210]

2. The Cities of O'Fallon and Ballwin note that the 6(M) rate for municipally-owned streetlight fixtures is lower than the corresponding 5(M) rate for streetlight fixtures owned by the company. They would like to explore the possibility of moving from the 5(M) rate to the lower 6(M) rate, believing that by doing so they could save a substantial amount of money.[211]

3. Steve Bender, Director of Public Works for the City of O'Fallon testified that his city pays over a million dollars per year under the 5(M) rate, but would pay only $180,000 per year under the 6(M) rate.[212] Robert Kuntz, City Administrator for the City of Ballwin, testified that his city would also pay less under the 6(M) rate.[213] Neither witness testified as to any additional costs the Cities would incur if they took responsibility for maintenance of the street lighting facilities under the 6(M) rate.

4. To qualify for service under the 6(M) tariff, the Cities must own their own streetlight fixtures. To that end, they have asked Ameren Missouri to negotiate to sell the fixtures at a fair market price.[214] Ameren Missouri has refused to enter into such negotiations.[215] The Cities ask the Commission to force Ameren Missouri to negotiate for the sale of the streetlights and have proposed a tariff modification to make that happen.[216]

5. Ameren Missouri explains that it is not interested in selling the streetlight

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[210] Davis Rebuttal, Ex. 9, Page 40, Lines 3-13.

[211] Bender Direct, Ex. 850, Page 3, Lines 6-12.

[212] Bender Direct, Ex. 850, Page 3, Lines 6-12.

[213] Kuntz Surrebuttal, Ex. 853, Page 4, Lines 8-12.

[214] Bender Direct, Ex. 850, Page 5, Lines 27-30.

[215] Wakeman Rebuttal, Ex. 46, Page 15, Lines 13-19.

[216] Bender Direct, Ex. 850, Attachment D.

fixtures to the Cities for two reasons. First, the company says it is in business to construct, own, and operate electrical distribution systems, including streetlights, not to build such systems for sale to other entities. Second, the company does not want to sell the streetlight fixtures because they are an integrated part of its electrical distribution system. [217]

6. David Wakeman, Ameren Missouri's Senior Vice President of Operations and Technical Services,[218] testified, and the Commission finds, that the component parts of the streetlight facilities are much more than just the light fixtures and poles visible from the street. As Wakeman explained, those components include: "streetlight fixtures, streetlight poles, cables supplying power to those streetlights and the supply to the cable, which can include transformers or secondary pedestals."[219]

7. The mere existence of these other components is not the only complicating factor. The real problem is that the other components are also used by Ameren Missouri to supply electric service to its other customers. The cables supplying power to the streetlights often share an underground trench with other distribution cables. The street light fixtures may be attached to poles that support other components of the overhead electric distribution system.[220]

8. For example, the electrical cable that feeds a streetlight might be fed out of a transformer that contains 12,000 volts of electricity and also serves the homes and businesses in the area.[221] Ameren Missouri's own technicians are trained to deal with that amount of electricity, but allowing other parties to have access to its electrical system would

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[217] Wakeman Rebuttal, Ex. 46, Page 17, Lines 10-14.

[218] Wakeman Rebuttal, Ex. 46, Page 1, Lines 11-13.

[219] Wakeman Rebuttal, Ex. 46, Page 16, Lines 15-17.

[220] Wakeman Rebuttal, Ex. 46, Page 16, Lines 17-22.

[221] Transcript, Page 1809, Lines 18-25.

put them, as well as the system, at risk.[222]

9. To avoid that problem, if the Cities were to take ownership of the streetlights, Ameren Missouri would have to reconstruct the system to separate the streetlights from the electric system and install a disconnect switch so that the Cities could shut off power to the streetlights if they needed to perform maintenance work on them.[223]

10. Some cities do own street lights that are served under the 6(M) rates. Generally, such systems are installed by the developer of a new subdivision and are separated from the rest of the electric distribution system by a disconnecting device.[224] In fact, the City of O'Fallon has an ordinance that requires developers of new subdivisions to construct streetlights that would conform to Ameren Missouri's 6(M) lighting requirements.[225]

11. The Cities want to be able to move to the 6(M) rate because they contend the 5(M) rate for company owned facilities is clearly excessive. They believe the rate is excessive because the amount by which the 5(M) rate exceeds the 6(M) rate amounts to approximately $185.00 per fixture, per year. Over the 33-year life span for such fixtures established in the company's depreciation schedules, the Cities believe they would pay more than three times the value of each fixture.[226] The Cities imply that Ameren Missouri is refusing to sell the streetlights to them to keep them captive to what they believe to be an unreasonably high 5(M) rate.

12. The Cities misunderstand how the Commission sets rates for the street

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[222] Wakeman Rebuttal, Ex. 46, Page 17, Lines 18-23.

[223] Transcript Page 1811, Lines 8-13.

[224] Transcript, Page 1822, Lines 19-24.

[225] Transcript, Page 1860, Lines 12-22.

[226] Bender Direct, Ex. 850, Page 3, Lines 13-28.

lighting class of customers. As is explained in more detail later in this order, Ameren Missouri and other parties to this case perform class cost of service analysis to determine the cost to serve each of the various rate classes. For purposes of those studies, the company-owned 5(M) service classification is combined with the customer-owned 6(M) classification into a single lighting class.[227] The class cost of service studies prepared by Ameren Missouri, Staff and MIEC all show that the lighting class as a whole currently pays rates that are close to Ameren Missouri's cost to serve that class.[228] That means that, in the long term, Ameren Missouri's overall income from the lighting class will be the same whether the Cities take service under the 5(M) or the 6(M) classification. If the Cities switch from the 5(M) classification to the 6(M) classification, rates will be adjusted between those classifications in a future rate case to account for that change to allow Ameren Missouri to recover its costs to serve the lighting class. Thus, Ameren Missouri does not have a financial incentive to "trap" its customers in the 5(M) classification.

13. Ameren Missouri's 5(M) tariff contains a provision that allows a street lighting customer to give notice to the company of its desire to discontinue receiving 5(M) service. Neither City has thus far given such notice to Ameren Missouri.[229] Much of the Cities' concern about Ameren Missouri's action is based on a fear that if they gave such notice, Ameren Missouri would scrap the existing streetlight fixtures rather than sell them to the Cities in place. They contend that such action by the company would be economically

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[227] Warwick Direct, Ex. 49, Page 5, Lines 7-10. Warwick's testimony indicates the company has three lighting classes, including "Municipal Lighting – Incandescent 7(M). The 7(M) classification has no customers and is to be eliminated in the revised tariffs that will result from this case. *See*. Davis Rebuttal, Ex. 9, Page 52, Lines 1-13.

[228] Davis Rebuttal, Ex. 9, Page 39, Lines 16-19.

[229] Transcript, Page 1864, Lines 3-6, as to the City of Ballwin. There is no indication in the record that the City of O'Fallon has issued such a notice.

wasteful and should be prevented by the Commission.

14. Because neither City has actually given notice of its intent to discontinue receiving 5(M) service, its concerns about economic waste from the scrapping of still useful streetlight fixtures is largely hypothetical. Ameren Missouri's witness, David Wakeman, testified several times that he did not know what the company would actually do with the existing street lighting fixtures if the Cities chose to discontinue 5(M) service.[230]

15. This is not the first time the Cities have brought this matter to the Commission's attention. In April 2014, the Cities filed a complaint before the Commission seeking to force Ameren Missouri to negotiate the sale of its street lighting facilities. The Commission handled that complaint in File No. EC-2014-0316. In August 2014, the Commission dismissed that complaint for failure to state a claim upon which relief can be granted, finding that it has no authority to order Ameren Missouri to sell property that it does not wish to sell. The Cities' appeal of the dismissal of their complaint is currently pending before Missouri's Western District Court of Appeals.[231]

Conclusions of Law:

A. The Cities claim that Section 393.140(5), RSMo 2000, gives the Commission authority to order Ameren Missouri to negotiate the sale of its street lighting fixtures to the Cities. The relevant portion of that statute says:

> Whenever the commission shall be of the opinion, after a hearing had upon its own motion or upon complaint, that … the acts or regulations of any such persons or corporations are unjust, unreasonable, unjustly discriminatory or unduly preferential or in any wise in violation of any provision of law, the commission shall determine and prescribe … the just and reasonable acts and regulations to be done and observed.

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[230] Transcript, Page 1797, Lines 13-24. *See also*, Page 1834, Lines 13-19.

[231] The pending appeal's file number at the Court of Appeals is WD78067.

On that basis, the Cities assert the Commission has authority to find that Ameren Missouri's refusal to negotiate the sale of the street lighting fixtures, and particularly its threat to scrap the fixtures rather than sell them to the Cities, is unjust and unreasonable and should be prohibited.

B. The specific statute that governs the transfer of utility property, Section 393.190.1, RSMo (Cum. Supp. 2013), in relevant part, says:

> No … electrical corporation … shall hereafter sell, assign, lease, transfer, mortgage or otherwise dispose of or encumber the whole or any part of its franchise, works or system, necessary or useful in the performance of its duties to the public, … without having first secured from the commission an order authorizing it so to do.

While that statute declares what the utility must do if it wants to sell used and useful property, it does not declare that the Commission can order a utility to sell such property. The Commission has only the authority given it explicitly by statute or reasonably incidental to such authority.[232] Thus, from negative implication, the Commission has no such authority.

C. Further, Section 71.525, RSMo 2000, restricts the ability of a municipality to condemn the used and useful property of a public utility if the municipality will use the property for the same or substantially similar purpose as the public utility. Subsection 71.525.3 goes on to make it clear that the limitations on condemnation apply "no matter whether any other … provision of law appears to convey the power of condemnation of such property by implication." Essentially, the Cities are asking the Commission to condemn Ameren Missouri's property to allow them to operate a street lighting system in

[232] *State ex rel. Praxair v. Pub. Serv. Com'n*, 344 S.W.3d 178, 192 (Mo 2011).

the company's place. Such action is forbidden by the statute.[233]

D. The Cities cite a 1987 telephone case as an example of a Commission finding that it does have authority to force a utility to sell its property.[234] In that case, the Commission found that it had sufficient authority to require independent telephone companies to essentially sell the company-owned telephone equipment inside customer homes to the customers. The companies had been paid for that equipment through accelerate depreciation. However, the basis for the Commission's finding of authority was a mandate from the Federal Communications Commission to take such action to enable the development of competition in the telephone industry. There is no such federal mandate in this case, and the *Detariffing* case does not justify a finding of Commission authority to order the sale of the street lighting fixtures.

E. The Commission will take administrative notice of its decision in in File No. EC-2014-0316.

Decision:

There has been a great deal of confusion, misunderstanding, and frustration surrounding this issue. But the actual issue before the Commission is quite narrow. The Cities ask the Commission to order Ameren Missouri to implement a tariff that would compel the Company to negotiate the sale of its street lighting fixtures when demanded by its customers. After considering the evidence and the arguments presented by the parties, the Commission decides that the tariff proposed by the Cities is not appropriate.

Previously, when the Cities filed a complaint to bring this question before the

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[233] *See also*, *City of Kirkwood v. Union Electric. Co.*, 896 S.W.2d 946 (Mo. App. E.D. 1995).

[234] *Investigation of the Detariffing of Embedded Customer Premises Equipment (CPE) Owned by Independent Telephone Companies*, 29 Mo. P.S.C. (N.S.) 299 (1987).

Commission, the Commission concluded that the complaint should be dismissed without a hearing because the Commission does not have authority to force Ameren Missouri to sell its property. The Commission will not contradict that earlier conclusion.

Further, having now heard evidence about the factual basis for the Cities' claim to Ameren Missouri's property, the Commission also concludes that the Cities' claim must fail on its facts. Even if it is assumed that Section 393.140(5), RSMo 2000, gives the Commission authority to compel Ameren Missouri to negotiate to sell its street lighting fixtures to correct an unjust or unreasonable act or regulation of the company, the Cities have not shown that Ameren Missouri has done anything unjust or unreasonable.

The cornerstone of the Cities' argument is that Ameren Missouri would be acting unreasonably and would be wasting ratepayer money if it were to actually choose to scrap the street lighting fixtures rather than allow the Cities an opportunity to buy them. Certainly, the Commission would closely examine the prudence of that decision in any future rate case where the company sought to recover such costs in rates. But at this time that is purely a hypothetical concern rather than a basis for granting relief to the Cities. The Commission will not require Ameren Missouri to implement a tariff requiring it to negotiate to sell its property to the Cities.

B. Should the Commission approve a revenue-neutral adjustment between customer-owned and Company-owned lighting rates?

Findings of Fact:

1. As previously discussed, the class cost of service studies prepared by all the parties to this case showed that the revenue Ameren Missouri collects from the overall

lighting class closely matches the company's cost to serve that class of customers.[235] But in response to the Cities' claim that the 5(M) rate was unreasonable, Ameren Missouri's witness, William Davis, took a closer look at the intra-class balance of the 5(M) and 6(M) rates. In his rebuttal testimony, Davis reports that the 5(M) rates are currently above their costs of service, and the 6(M) rates are correspondingly below their cost of service.[236]

2. To adjust the 5(M) and 6(M) rate to make them match their actual cost of service would require a $3.9 million increase to the 6(M) rate schedule, with a corresponding $3.9 million decrease to the 5(M) rate. Because the 6(M) rate class is much smaller than the 5(M) rate class, the $3.9 million shift would roughly double the rates for the 6(M) rate class while reducing the rates for the 5(M) rate class by about 11 percent.[237] The shift would be revenue neutral for Ameren Missouri.

3. William Davis suggested the Commission might want to take steps in this rate case to move the 5(M) and 6(M) rate classifications closer to their actual costs of service. He proposes a gradual shifting of those costs to avoid a rate shock for the 6(M) customers, but did not actually propose such a shift in this case. Since he did not raise the possible rate shift until he filed his rebuttal testimony, the other parties did not have an opportunity to verify Davis' intra-class cost of service findings.

Conclusions of Law:

The Commission makes no additional conclusions of law for this sub-issue.

Decision:

The Commission is concerned that Ameren Missouri's cost recovery from the 5(M)

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[235] Davis Rebuttal, Ex. 9, Page 39, Lines 16-19.

[236] Davis Rebuttal, Ex. 9, Page 40, Lines 16-21.

[237] Davis Rebuttal, Ex. 9, Pages 40-41, Lines 21-23, 1-2.

and 6(M) classification within the overall lighting class be balanced to match the company's cost to serve those classifications. However, the Commission is not willing to make such rate shifts until all parties have an opportunity to review the basis for such a shift.

The Commission will not order a rate shift between the 5(M) and 6(M) rate classifications at this time, but will direct Ameren Missouri to further study the appropriateness of the 5(M) rate compared to the 6(M) and to present the results of that study in its direct case for its next rate case.

C. Should the Commission eliminate the termination fees from the Ameren Missouri-owned lighting rate?

Findings of Fact:

1. The Cities challenge a provision in Ameren Missouri's current lighting tariffs that creates a $100 per lamp early termination fee applicable if a street lighting customer in the 5(M) classification asks the company to remove the fixtures within either three or ten years of the installation of the fixture, depending upon the type of fixture to be removed. The Cities denounced that early termination fee as an unreasonable barrier to their goal of migrating from the 5(M) classification to the 6(M) classification.[238]

2. The early termination fees would apply to about ten percent of the total streetlights in the two cities.[239]

3. The fee is not designed to recover the full cost of the street lighting fixtures that would be removed. Rather, the early termination fee is intended to give a customer pause before requesting a change in a lighting service. For example, it is designed to discourage a customer from initially requesting a mercury vapor light and three months

[238] Bender Direct, Ex. 850, Page 4, Lines 16-27.

[239] Transcript, Page 1861, Lines 20-24, and Page 1864, lines 15-18.

later asking to change to a high pressure sodium light.[240]

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The early termination fee is a reasonable provision in Ameren Missouri's lighting tariff designed to ensure the costs incurred by the company are paid by the customers that cause that cost. The Commission will not order Ameren Missouri to remove that fee from its tariff.

13. Labadie ESPs

A. Should the Company's investment in electrostatic precipitators installed at the Labadie Energy Center be included in the Company's rate base?

Findings of Fact:

1. Ameren Missouri has installed electrostatic precipitators (ESPs)[241] at Units 1 and 2 of its coal-fired Labadie Energy Center to comply with the U.S. Environmental Protection Agency's (EPA's) Mercury and Air Toxics Standards (MATS) rule.[242] It now seeks to add the installation costs to its rate base.

2. Staff determined that the construction and testing requirements for the ESP's for Unit 2 were completed in August 2014 and for Unit 1 in December 2014. The ESPs for both units were fully operational and in-service before the December 31, 2014 end of the

[240] Davis Rebuttal, Ex. 9, Page 43, Lines 7-18.

[241] Staff describes the ESPs as "highly efficient filtration devices consisting of several chambers that contain numerous electro-statically charged steel plates that collect and remove fine particulate matter from flowing emission gases." Staff Revenue Requirement Report, Ex. 202, Page 49, Lines 14-16.

[242] Michels, Amended Rebuttal, Ex. 26, Page 2, Lines 13-16.

true-up period.[243]

3. Staff has reviewed the installation of the ESPs and has determined the trued-up costs pertaining to that project as of December 31, 2014.[244]

4. No party challenged the fact that the ESPs are used and useful or the amount of costs incurred to install the pollution control devices. However, Sierra Club challenged the prudence of Ameren Missouri's decision to install the ESPs. Sierra Club does not oppose pollution control devices in general but contends Ameren Missouri has not sufficiently studied the relative cost of immediately shutting down the Labadie coal-fired plant rather than incurring the cost to install the ESPs and additional pollution control devices that will need to be installed in the future, as well as the possibility that the plant will need to be shut down in the relatively near future to comply with the U.S. Environmental Protection Agency's proposed carbon limiting regulations.[245]

5. In response to Sierra Club's criticisms, Ameren Missouri offered the rebuttal testimony of Matt Michels, Ameren Missouri's Senior Manager of Corporate Analysis. Mr. Michels pointed to Ameren Missouri's recent Integrated Resource Plan (IRP) filing to demonstrate that installing the ESPs and keeping the plant in operation was cost effective.[246]

6. In response to Michels' rebuttal testimony, Sierra Club's witness, Dr. Hausman, narrowed his criticism of Ameren Missouri's Labadie analysis to two points.[247]

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[243] Staff Revenue Requirement Report, Ex. 202, Page 49, Lines 17-28.

[244] Carle Surrebuttal, Ex. 208, Page 5, Lines 12-14. The precise cost is highly confidential.

[245] Hausman Direct, Ex. 900, Pages 5-13.

[246] Michels Rebuttal, Ex. 26.

[247] Sierra Club's briefs also delve into broader criticisms of Ameren Missouri's IRP filing. The overall adequacy of the IRP filing is not being litigated in this proceeding. The only issue before the

First, he disagrees with Ameren Missouri's modeling in its IRP of the cost of compliance with greenhouse gas restrictions that might be imposed by the EPA's proposed Clean Power Plan.[248] Second, he contends Ameren Missouri should have modeled the option of retiring either Labadie Unit 1 or Unit 2 individually rather than as the whole plant because perhaps one unit could be retired without requiring any investment in replacement generation or transmission upgrades, even if the entire plant could not.[249]

7. Because of these deficiencies, Hausman recommends the Commission refuse to allow Ameren Missouri to include the ESP installation costs in rate base until the company "resolves these deficiencies and presents the Commission with an adequate justification for the prudence of these expenditures."[250]

8. The EPA's proposed Clean Power Plan was proposed in June 2014, but it is not yet in final form and no one knows how the final regulation regulate carbon emissions. Ameren Missouri's IRP analysis assumed that there was an 85 percent chance that any carbon restricting regulation would require indirect regulation of carbon emissions rather than placing a specific price on such emissions.[251] The currently proposed regulations do not include a carbon tax or a cap and trade regime that would impose such direct costs.[252]

9. The alternative to imposition of a direct cost on carbon emissions is indirect regulation where instead of making carbon emissions more expensive directly, the regulation would require utilities to replace polluting generating sources with less polluting

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Commission at this time is the prudence of Ameren Missouri's decision to install the ESPs at Labadie Units 1 and 2.

[248] Hausman Surrebuttal, Ex. 901, Pages 5-9.

[249] Hausman Surrebuttal, Ex. 901, Page 10, Lines 1-15.

[250] Hausman Surrebuttal, Ex. 901, Page 9, Lines 18-22.

[251] Transcript, Page 1937, Lines 12-25.

[252] Transcript, Pages 1942-1943, Lines 24-25, 1-3.

sources. So, for example, a coal-fired plant might be replaced by a natural gas-fired combined-cycle plant.[253] That also means that less efficient coal-fired plants, plants that produce more carbon dioxide because they are less efficient, would be retired before the Labadie plant, which is relatively efficient.[254] The retirement of less efficient coal fired plants would increase electricity prices, which would make the Labadie plant more profitable[255]

10. Based on that scenario, which Ameren Missouri reasonably found to be most likely, Ameren Missouri's IRP study concluded that investing in environmental controls, along with other investments and operating costs needed to keep Labadie operating until 2023 would save customers $3.6 billion.[256]

11. Ameren Missouri is required to comply with the MATS rule by April 16, 2016. Ameren Missouri needed to either install the ESPs by that time, or shut down the Labadie plant by that date to comply with the rule.[257] Shutting down the Labadie plant by April 2016 would require additional upgrades to the transmission grid to ensure reliability as well as the addition of new generating capacity.[258]

Conclusions of Law:

A. Sierra Club challenges the prudence of Ameren Missouri's decision to install ESP's at Units 1 and 2 of its Labadie Plant rather than shut down the plant by April 2016 in order to comply with the MATS standards. That challenge implicates what is described as

[253] Transcript, Page 1943, Lines 3-24.

[254] Transcript, Page 1949, Lines 10-25.

[255] Transcript, Page 1938, Lines 17-25.

[256] Michels Amended Rebuttal, Ex. 26, Page 12, Lines 6-10.

[257] Michels Amended Rebuttal, Ex. 26, Page 17, Lines 6-10. *See also*, Hausman Direct, Ex. 900, Page 9, Lines 1-13.

[258] Michels Amended Rebuttal, Ex. 26. Page 18, Lines 10-16.

the prudence standard. Missouri's courts have described that standard as follows:

> A utility's costs are presumed to be prudently incurred. The presumption does not, however, survive a showing of inefficiency or improvidence. If some other participant in the proceedings alleges that the utility has been imprudent in some manner, that participant has the burden of creating a serious doubt as to the prudence of the expenditure. If that is accomplished, the utility then has the burden of dispelling those doubts and proving the questioned expenditure was in fact prudent. The prudence test should not be based upon hindsight but upon reasonableness. The utility's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the utility had to solve its problem prospectively rather than in reliance on hindsight. In effect, the PSC's responsibility is to determine how reasonable people would have performed the tasks that confronted the utility.[259]

Thus, Sierra Club has the burden of demonstrating a serious doubt about the prudence of Ameren Missouri's decision before Ameren Missouri must defend its prudence

Decision:

Sierra Club has not carried its burden of demonstrating a serious doubt about the prudence of Ameren Missouri's decision to install ESPs at Unit 1 and Unit 2 of its Labadie plant. Indeed, Sierra Club does not actually allege that the installation of the ESPs at Labadie was imprudent. Rather, it contends Ameren Missouri did not perform a sufficient analysis of costs and benefits to properly determine whether customers would have been better off if the company had immediately shut down one or more of the Labadie units to comply with an April 2016 deadline to comply with the EPA's MATS regulation. Yet, Ameren Missouri's IRP analysis demonstrated that ratepayers would save approximately $3.6 billion if the Labadie plant remains on line until 2023.

Sierra Club also speculates that Ameren Missouri did not perform a sufficient analysis to assess the possibility that future greenhouse gas regulations might make

[259] *Atmos Energy Corp. v. Office of Public Counsel*, 389 S.W.3d 224, 228 (Mo. App. W.D. 2012).

continued operation of the Labadie plant financially unviable. Ameren Missouri's analysis took into account its reasonable evaluation of what such regulations would likely require, but no such greenhouse gas regulations are currently in effect, and no one can know with any certainty what form such regulations might take in the future.

Sierra Club's criticisms of Ameren Missouri's cost-benefit analysis may be an appropriate topic to be raised when Ameren Missouri's IRP filing is discussed, but Ameren Missouri's decision to install the now fully operational and in-service ESPs is presumed to be prudent. Those costs identified in Staff's testimony may be included in Ameren Missouri's rate base.

14. Fuel Adjustment Clause ("FAC")

The parties identified several sub-issues regarding Ameren Missouri's fuel adjustment clause (FAC). Many of those issues regarded disputes between Public Counsel and Ameren Missouri about the sufficiency and timeliness of the evidentiary support the company offered to justify continuation of the FAC. During the course of the hearing, Public Counsel and Ameren Missouri filed a non-unanimous stipulation and agreement that resolved all disagreements between those parties and allowed for the continuation of the FAC with a few changes that were incorporated into a proposed tariff attached to the stipulation and agreement.[260]

Consumers Council objected to the stipulation and agreement because it presupposes that the FAC will be continued, a result it opposes. Because of Consumers Council's objection, the Commission cannot approve the non-unanimous stipulation and

[260] Non-Unanimous Stipulation and Agreement Regarding Some Fuel Adjustment Clause Issues. Filed March 6, 2015.

agreement[261] and must resolve the issues based on competent and substantial evidence. The non-unanimous stipulation and agreement becomes merely a joint position statement of the signatory parties to which they are not bound. However, both Ameren Missouri and Public Counsel have indicated their intent to adhere to that joint position.

Should Ameren Missouri be allowed to continue to use a fuel adjustment clause?

Findings of Fact:

1. Before addressing other issues regarding the implementation of Ameren Missouri's fuel adjustment clause, the Commission must address the fundamental issue of whether Ameren Missouri should be allowed to continue to use a fuel adjustment clause.

2. The Commission first allowed Ameren Missouri to implement a fuel adjustment clause in a previous Ameren Missouri rate case, ER-2008-0318. .[262] The approved fuel adjustment clause includes an incentive mechanism that requires Ameren Missouri to pass through to its customers 95 percent of any deviation in fuel and purchased power costs from the base level. The other 5 percent of any deviation is retained or absorbed by Ameren Missouri.[263] The Commission has approved the continuation of that fuel adjustment clause in each subsequent Ameren Missouri rate case.

3. In this case, Ameren Missouri proposed that the Commission allow it to continue to use its existing fuel adjustment clause.[264] Consumers Council did not present

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[261] Commission Rule 4 CSR 240-2.115(D).

[262] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 361, January 27, 2009.

[263] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, 18 Mo. P.S.C. 3d 306, 366-367, January 27, 2009.

[264] Barnes Direct, Ex. 2, Pages 3-4, Lines 23,1-2.

any testimony on this issue, but it did cross examine witnesses presented by other parties and urged the Commission to discontinue Ameren Missouri's fuel adjustment clause. Consumers Council also asks the Commission to change the existing sharing mechanism to create a 50/50 split, with Ameren Missouri retaining or absorbing half of any deviation from the base level of fuel and purchased power costs. The Commission will address the proposed modification of the sharing mechanism in the next section of this report and order.

4. When it first allowed Ameren Missouri to implement a fuel adjustment clause in ER-2008-0318, the Commission found that Ameren Missouri should be allowed to establish a fuel adjustment clause because its fuel costs were substantial, beyond the control of the company's management, and volatile in amount. The Commission also found that Ameren Missouri needed a fuel adjustment clause to have a sufficient opportunity to earn a fair return on equity and to be able to compete for capital with other utilities that have a fuel adjustment clause.[265] In the same rate case, the Commission found that a 95/5 sharing mechanism would give Ameren Missouri a sufficient opportunity to earn a fair return on equity, while protecting customers by preserving the company's incentive to be prudent.[266]

5. Ameren Missouri's net energy costs have risen substantially since the last rate case to approximately $696 million, an increase of 23 percent.[267] Fuel and purchased

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[265] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Pages 69-70.

[266] *In the Matter of Union Electric Company, d/b/a AmerenUE's Tariffs to Increase its Annual Revenues for Electric Service*, Report and Order, Case No. ER-2008-0318, January 27, 2009, Page 76.

[267] Barnes Rebuttal, Ex. 3, Page 21, Lines 5-8.

power costs, including transportation, are still the company's largest operating and maintenance (O&M) expense, comprising approximately 51 percent of its total O&M costs.[268] Coal costs have increased, and off-system sales have declined. Further increases in coal costs are anticipated, and no one knows what will happen to off-system sales revenue.[269] Those fuel and purchased power costs continue to be dictated by national and international markets and thus are outside the control of Ameren Missouri's management. Finally, these costs and revenues continue to be volatile.[270]

6. Ameren Missouri still needs a fuel adjustment clause to help alleviate the effects of regulatory lag as net fuel costs continue to rise. In addition, Ameren Missouri still must compete in the capital markets with other utilities, and the vast majority of those utilities have fuel adjustment clauses. The continued existence of a fuel adjustment clause is important to maintaining Ameren Missouri's credit worthiness.[271]

7. Finally, Consumers Council expresses concern that the existence of the FAC has contributed to "excessive" earnings by Ameren Missouri. That claim of past "excessive" earnings is based on the per-book quarterly surveillance reports that Ameren Missouri has filed since it was first allowed to have an FAC in 2009. Such surveillance reports merely provide a snapshot of unadjusted book earnings[272] and are not suitable to establish just and reasonable rates. In any event, those surveillance reports show that Ameren Missouri was earning less than its authorized return on equity more often than it

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[268] Barnes Rebuttal, Ex. 3, Page 21, Lines 1-5.

[269] Barnes Rebuttal, Ex. 3, Page 22, Lines 11-19.

[270] Barnes Rebuttal, Ex. 3, Page 25, Lines 1-9.

[271] Rygh Rebuttal, Ex. 42, Pages 6-16.

[272] Reed Surrebuttal, Ex. 41, Page 16, Lines 4-7.

was earning more than its authorized return during the five years since Ameren Missouri was first allowed to implement an FAC.[273]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), allows the Commission to establish and continue a fuel adjustment clause for Ameren Missouri.

B. Commission Rule 4 CSR 240-2.115(2)(D) states:

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

Decision:

Ameren Missouri still needs to have a fuel adjustment clause in place if it is to have a reasonable opportunity to earn a fair return on its investments. The Commission concludes Ameren Missouri should be allowed to continue to implement a fuel adjustment clause.

A. Did the Company fail to comply with the "complete explanation" provisions of 4 CSR 240-3.161(3)(H) and (I) and, if so, would this justify the elimination of the Company's fuel adjustment clause?

Findings of Fact:

1. As described in the conclusions of law for this issue, the Commission's rules regarding the FAC require that the electric utility seeking to continue an FAC file detailed information as part of its direct filing to institute the rate case. Public Counsel's witness, Lena Mantle, testified that Ameren Missouri failed to provide a complete explanation in its direct case of all the costs and revenues that it wanted to be included in its FAC.[274] On that basis, she urged the Commission to discontinue the FAC because the information Ameren

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[273] Reed Surrebuttal, Ex. 41, Pages 14-15, Figures 1 and 2.

[274] Mantle Direct, Ex. 400, Pages 9-10, Lines 16-22, 1-2.

Missouri filed did not provide the Commission with the information needed to make an informed decision.[275]

2. Ameren Missouri purported to offer the required minimum filings in an attachment to the direct testimony of Lynn Barnes.[276] When Public Counsel challenged the sufficiency of that filing, Barnes responded by testifying that the level of detail in Ameren Missouri's filing matches that offered in previous rate cases and that those previous filings have been found to be sufficient by Staff and the Commission.[277]

3. In the objected-to stipulation and agreement, now the joint position of Ameren Missouri and Public Counsel, those parties agreed to meet no later than May 30, 2015, to discuss additional information that Ameren Missouri should provide about costs and revenues when it files a request to continue its FAC in its next rate case. Ameren Missouri and Public Counsel agree to file their agreed-upon account, subaccount and activity code descriptions in this case by August 1, 2015. With that understanding, they agree the FAC should be continued in this case.

Conclusions of Law:

A. Commission rule 4 CSR 240-3.161 establishes certain filing requirements for electric utilities that are seeking to continue a previously established FAC. Subsection (3) of that rule says:

> When an electric utility files a general rate proceeding following the general rate proceeding that established its RAM [another word for FAC] as described by 4 CSR 240-20.090(2) in which it requests that its RAM be continued or modified, the electric utility shall file with the commission and serve parties … the following supporting information as part of, or in addition

[275] Mantle Direct, Ex. 400, Pages 17-18, Lines 20-23, 1.

[276] Ex. 3.

[277] Barnes Rebuttal, Ex. 3, Page 7, Lines 1-16. *See also, In the Matter of the Tariffs of Aquila, Inc.,* Report and Order, File No. ER-20107-0004, 15 Mo. P.S.C. 3d 416, May 17, 2007.

to, its direct testimony: …
(H) A complete explanation of all the costs that shall be considered for recovery under the proposed RAM and the specific account used for each cost item on the electric utility's books and records;
(I) A complete explanation of all the revenues that shall be considered in the determination of the amount eligible for recovery under the proposed RAM and the specific account where each such revenue item is recorded on the electric utility's books and records.

Decision:

The minimum filings Ameren Missouri made in this case are substantially similar to the filings it made in past rate cases and have never been challenged in the past. That does not mean those minimum filings cannot be improved in the future. Public Counsel and Ameren Missouri's agreement to meet to discuss those requirements is helpful, and the Commission anticipates the filing those parties intend to make by August 1. However, the dispute about the details of those filing is not a sufficient justification for the termination of the FAC. Ameren Missouri and Public Counsel have reached a reasonable settlement of their dispute, and the Commission will take no further action at this time.

B. Did the Company fail to provide information on the magnitude, volatility and the Company's ability to manage the costs and revenues that it proposes to include in its FAC and, if so, would this justify the elimination of the Company's fuel adjustment clause?

Findings of Fact:

1. In her direct testimony, Public Counsel's witness, Lena Mantle, testified that Ameren Missouri did not provide sufficiently detailed information about the magnitude, volatility and the company's ability to manage the costs and revenues that it proposes to include in its FAC.[278]

2. Ameren Missouri's witness, Lynn Barnes, offered limited, conclusory information about magnitude, volatility, and ability to manage costs and revenue within the

[278] Mantle Direct, Ex. 400, Pages 13-16.

FAC in her direct testimony.[279] In her rebuttal testimony, Barnes disagreed that detailed testimony was required when the utility is merely seeking to continue an existing FAC.[280] However, she then offered much more detailed testimony on that topic.[281]

3. Public Counsel and Ameren Missouri have entered into an objected-to stipulation and agreement which remains their joint position. In that joint position, Public Counsel drops its position that the FAC be eliminated.

Conclusions of Law:

A. In relevant part, Commission Rule 4 CSR 240-20.090(2)(C) says:

> In determining which cost components to include in a RAM, the commission will consider, but is not limited to considering, the magnitude of the costs, the ability of the utility to manage the costs, the volatility of the cost component and the incentive provided to the utility as a result of the inclusion or exclusion of a cost component. …

That regulation does not require the utility to file any specific information, nor does it require the utility to file such information in its direct case.

Decision:

The direct testimony offered by Ameren Missouri provided limited information about the continuing need for the FAC. However, when the sufficiency of that testimony was challenged by Public Counsel, Ameren Missouri responded with more extensive testimony in its rebuttal testimony. Ameren Missouri has provided sufficient information to allow the Commission to find that the FAC should be continued.

C. If the FAC continues should the sharing percentage be changed to 90%/10%?

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[279] Barnes Direct, Ex. 2, Page 5, Lines 6-22.

[280] Barnes Rebuttal, Ex. 3, Page 13, Lines 5-10.

[281] Barnes Rebuttal, Ex. 3, Pages 21-29.

Findings of Fact:

1. Under the current FAC, Ameren Missouri passes 95 percent of eligible costs and revenues through the FAC. The remaining 5 percent is not passed through the FAC so that Ameren Missouri will retain an incentive to minimize its costs and maximize its revenue. Public Counsel initially urged the Commission to modify the sharing percentages incorporated in the FAC from a 95/5 split to a 90/10 split.[282] Consumers Council did not present any additional testimony on this question, but if the Commission does not totally eliminate the FAC, it advocates for a 50-50 split between rate payers and shareholders.

2. Public Counsel and Ameren Missouri have entered into an objected-to stipulation and agreement which remains their joint position. In that joint position, Public Counsel drops its position that the sharing mechanism be changed.

3. Since Ameren Missouri has had an FAC with a 95/5 sharing split, that 5 percent share amounts to $38 million of prudently incurred net fuel costs that the company will never be able to recover.[283] Even to a company as large as Ameren Missouri, $38 million is a significant incentive.

4. Giving Ameren Missouri a greater incentive to minimize its costs and maximize its off-system sales would be meaningless if there is little the company can actually do to minimize costs or maximize off-system sales. In general, Ameren Missouri's fuel costs are dictated by national and international markets that are largely beyond the company's control.[284]

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[282] Mantle Direct, Ex. 400, Pages 23-25.

[283] Barnes Rebuttal, Ex. 3, Page 46, Lines 1-18.

[284] Barnes Rebuttal, Ex. 3, Page 53, Lines 18-22.

5. Most other utilities with FACs do not have a sharing mechanism at all.[285]

6. Ameren Missouri's existing FAC, with the 95/5, has allowed the company to borrow money at a lower cost. Ameren Missouri's witness, Gary Rygh, an investment banker with Barclays, PLC, explains:

> Since 2009 [when the FAC began] Ameren Missouri has raised approximately $1.2 billion of debt, and each time the cost of that debt came in below the prevailing index at the time instead of above the cost of the index which was the case in prior Ameren Missouri debt offerings. The savings total about $8.6 million in interest costs every year for the life of the bonds that Ameren Missouri issued.

Over the life of the bonds, the savings amount to approximately $210 million, which ends up reducing customer rates.[286]

7. Furthermore, changing the sharing percentage without a good reason to do so could erode investor confidence in the utility and in the state regulatory process.[287]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), the statute that allows the Commission to establish a fuel adjustment clause 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.

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[285] Barnes Rebuttal, Ex. 3, Page 52, Lines 7-11.

[286] Rygh Rebuttal, Ex. 42, Page 20, Lines 14-21.

[287] Barnes Rebuttal, Ex. 3, Page 53, Lines 1-3. See also, Rygh Rebuttal, Ex. 42, Pages 14-19.

Subsection 4 of that statute sets out some of the provisions that must be included in a fuel adjustment clause as follows:

> The commission shall have the power to approve, modify, or reject adjustment mechanisms submitted under subsections 1 to 3 of this section only after providing the opportunity for a full hearing in a general rate proceeding, including a general rate proceeding initiated by complaint. The commission may approve such rate schedule after considering all relevant factors which may affect the cost or overall rates and charges of the corporation, provided that it finds that the adjustment mechanism set forth in the schedules:
>
> **(1) Is reasonably designed to provide the utility with a sufficient opportunity to earn a fair return on equity;**
>
> (2) Includes provisions for an annual true-up which shall accurately and appropriately remedy any over- or under-collections, including interest at the utility's short-term borrowing rate, through subsequent rate adjustments or refunds;
>
> (3) In the case of an adjustment mechanism submitted under subsections 1 and 2 of this section, includes provisions requiring that the utility file a general rate case with the effective date of new rates to be no later than four years after the effective date of the commission order implementing the adjustment mechanism. …
>
> (4) In the case of an adjustment mechanism submitted under subsections 1 or 2 of this section, includes provisions for prudence reviews of the costs subject to the adjustment mechanism no less frequently than at eighteen-month intervals, and shall require refund of any imprudently incurred costs plus interest at the utility's short-term borrowing rate. (emphasis added)

Subsection 4(1) is emphasized because that is the key requirement of the statute. Any fuel adjustment clause the Commission allows Ameren Missouri to implement must be reasonably designed to allow the company a sufficient opportunity to earn a fair return on equity.

B. Subsection 7 of the fuel adjustment clause statute provides the Commission with further guidance, stating the Commission may:

> take into account any change in business risk to the corporation resulting from implementation of the adjustment mechanism in setting the corporation's allowed return in any rate proceeding, in addition to any other changes in business risk experienced by the corporation.

Finally, subsection 9 of that statute requires the Commission to promulgate rules to "govern the structure, content and operation of such rate adjustments, and the procedure for the submission, frequency, examination, hearing and approval of such rate adjustments." In compliance with the requirements of the statute, the Commission promulgated Commission Rule 4 CSR 240-3.161, which establishes in detail the procedures for submission, approval, and implementation of a fuel adjustment clause.

C. Specifically, Commission Rule 4 CSR 240-3.161(3) establishes minimum filing requirements for an electric utility that wishes to continue its fuel adjustment clause in a rate case subsequent to the rate case in which the fuel adjustment clause was established. Ameren Missouri has met those filing requirements.

Decision:

There is no sufficient reason to change the existing 95/5 sharing percentage under which Ameren Missouri has operated for the past several years. Imposing a significant financial burden on the company simply to experiment with an alternative sharing percentage would be unfair to the company. The Commission finds there is no reason to change the sharing percentages in the fuel adjustment clause The Commission will retain the current 95%-5% sharing mechanism included in Ameren Missouri's fuel adjustment clause.

D. What transmission charges should be included in the FAC?

Findings of Fact:

1. As will be discussed in more detail in the Conclusions of Law for this issue, the Missouri statute that allows the Commission to establish a fuel adjustment clause limits the application of the fuel adjustment clause to increases and decreases in fuel and

purchased-power costs, including transportation.[288]

2. Ameren Missouri currently includes all the MISO wholesale transmission expense it incurs in the fuel adjustment clause, as it was allowed to do by the Commission in the last Ameren Missouri rate case.[289]

3. The Commission's decision in the last rate case was challenged on appeal by several parties, including MIEC. The Commission's decision was upheld, but MIEC's argument that transmission costs for "purchased power" should not include transmission costs related to self-generated power was found by the court to have been raised for the first time at the appellate court. Thus it was not preserved for appeal and was not addressed by the court.[290] MIEC now raises that argument to the Commission for the first time.

4. By the terms of MISO's tariff, Ameren Missouri, as a result of its participation in the MISO market, sells all the power it generates into the MISO market and then purchases back all the power it needs to serve its native load from the MISO market.[291] That fact is not disputed by any party.

5. In other contexts, Ameren Missouri recognizes the distinction between serving its native load and making off-system sales. For example, when accounting for fuel costs, the company separates fuel expense to serve native load from fuel expense to make off-system sales.[292]

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[288] Section 386.266.1, RSMo (Cum. Supp. 2013).

[289] In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase its Annual Revenues for Electric Service, Report and Order, File No. ER-2012-0166, December 12, 2012.

[290] *In re Union Elec. Co.,* 422 S.W.3d 358 (Mo. App. W.D. 2013).

[291] Haro Rebuttal, Ex. 14, Page 18, Lines 1-17.

[292] Dauphinais Surrebuttal, Ex. 509, Page 9, Lines 1-13. *And see* Exhibits. 524-528

6. In addition to the distinction between serving native load and making off-system sales, Ameren Missouri can also purchase power from MISO or other third parties to supplement its self-generated power.[293] All three scenarios are reasons why Ameren Missouri could incur wholesale transmission costs under FERC Account 565, and these are the transmission costs Ameren Missouri seeks to pass through its FAC.[294]

7. Furthermore, under FERC Order 668, public utilities must net their MISO-cleared load and generation in each hour and report that net amount as either: (i) sale for resale (i.e. off-system sale under account 447 when the utility's cleared generation exceeds the cleared load, or (ii) a power purchase under Account 555 when the utility's cleared load exceeds its cleared generation. That order states "Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load."[295] That means that for accounting purposes, Ameren Missouri is required to recognize the distinction between off-system sales, power purchased to supplement its generation and self-generated power .

8. The transmission charges that Ameren Missouri is incurring from MISO are rapidly rising. This is principally due to MISO Schedule 26-A charges, which recover the cost of regionally funded Multi-Value Transmission Projects (MVPs). The Schedule 26-A rate was zero four years ago, but is expected to be $0.58 per MWh in 2015 and is forecasted to rise to $1.65 per MWh by 2021. Such an increase could increase the charges to Ameren Missouri by $40 million or more.[296]

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[293] Dauphinais Direct, Ex. 508, Page 4, Lines 12-17.

[294] Dauphinais Direct, Ex. 508, Page 4, Lines 9-12, and Page 6, Lines 19-20.

[295] Dauphinais Surrebuttal, Ex. 509, Page 10, Lines 7-22, and Ex. 66.

[296] Dauphinais Direct, Ex. 508, Page 5, Lines 1-13.

9. Ameren Missouri will be allowed to recover those increased costs in its future rates, but unless those costs are flowed through the FAC it will not be able to recover the increases that occur between rate cases.[297]

10. Only 3.5 percent of the MISO transmission charges incurred by Ameren Missouri to serve its load are related to true purchased power. The other 96.5 percent are incurred to transport power from Ameren Missouri's own generation to serve its own native load.[298]

11. The Commission has approved a unanimous stipulation and agreement on Net Base Energy Costs, which establishes how those transmission costs and revenues will be treated as well as the amount of costs that will be added to base rates if MISO transmission charges are not flowed through the FAC.[299]

Conclusions of Law:

A. Section 386.266.1, RSMo (Cum. Supp. 2013), the statute that allows the Commission to establish a fuel adjustment clause 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

[297] Dauphinais Direct, Ex. 508, Page 5, Lines 13-21.

[298] Dauphinais Direct, Ex. 508, Page 11, Lines 1-18.

[299] Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets, Filed March 5, 2015. Approved by Order issued on March 19, 2015.

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:

The evidence demonstrated that for purposes of operation of the MISO tariff, Ameren Missouri sells all the power it generates into the MISO market and buys back whatever power its needs to serve its native load. From that fact, Ameren Missouri leaps to its conclusion that since it sells all its power to MISO and buys all that power back, all such transactions are off-system sales and purchased power within the meaning of the FAC statute. The Commission does not accept this point of view.

The drafters of the FAC statute likely did not envision a situation where a utility would consider all its generation purchased power or off-system sales. In fact, the policy underlying the FAC statute is clear on its face. The statute is meant to insulate the utility from unexpected and uncontrollable fluctuations in transportation costs of purchased power. At the time the statute was drafted, and even in our more complex present-day system, 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 it load are the costs that are unexpected and out of the utility's control to such an extent that a deviation from traditional rate making is justified.

Therefore, of the three reasons Ameren Missouri incurs transmission costs cited earlier, the costs that should 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 MISO (off-system sales).

Any other interpretation would expand the reach of the FAC beyond its intent.

E. If the FAC continues, what costs and revenues should be included in the Company's FAC?

1. Should only fuel and purchased power costs, transportation of the fuel commodity, transmission associated with purchased power costs and off-system sales revenues be included?
2. If costs and revenues other than those listed in item 1 above are included in the FAC, should cost or revenue types in which the Company has incurred less than $360,000 in the test year be included, and what charges and revenues from MISO should be included?

Findings of Fact:

1. In her rebuttal testimony,[300] Public Counsel's witness, Lena Mantle, described in detail what costs and revenues she believed should be flowed through the FAC. The objected-to stipulation and agreement, which is now the joint position of Public Counsel and Ameren Missouri, contains a sample tariff that incorporates the agreement between Public Counsel and the company regarding the costs and revenues to be flowed through the FAC.[301]

2. Consumers Council objected to the continuation of the FAC at a higher level, but did not file any testimony or make any argument at this level of granularity.

Conclusions of Law:

The Commission makes no additional conclusions of law for this issue.

Decision:

The sample tariff that was included as part of the joint position of Ameren Missouri and Public Counsel is a reasonable resolution of the question and may be used in so far as it is consistent with the other stipulations and agreements approved by the Commission.

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[300] Ex. 401.

[301] Non-Unanimous Stipulation and Agreement Regarding Some Fuel Adjustment Clause Issues, filed March 6, 2015.

3. Should transmission revenues continue to be included in the FAC?

This sub-issue was resolved by stipulation and agreement.[302]

15. Noranda Rate Proposal

A. Is Noranda experiencing a liquidity crisis such that it is likely to cease operations at its New Madrid smelter if it cannot obtain relief of the sort sought here?

1. If so, would the closure of the New Madrid smelter represent a significant detriment to the economy of Southeast Missouri, to local tax revenues, and to state tax revenues?
2. If so, can the Commission lawfully grant the requested relief?
3. If so, should the Commission grant the requested relief?

B. Would rates for Ameren Missouri's ratepayers other than Noranda be lower if Noranda remains on Ameren Missouri's system at the reduced rate?

C. Would it be more beneficial to Ameren Missouri's ratepayers other than Noranda for Noranda to remain on Ameren Missouri's system at the requested reduced rate than for Noranda to leave Ameren Missouri's system entirely?

D. Is it appropriate to redesign Ameren Missouri's tariffs and rates on the basis of Noranda's proposal, as described in its Direct Testimony and updated in its Surrebuttal Testimony?
1. If so, should Noranda be exempted from the FAC?
2. If so, should Noranda's rate increases be capped in any manner?
3. If so, can the Commission change the terms of Noranda's service obligation to Ameren Missouri and of Ameren Missouri's service obligation to Noranda?
4. If so, should the resulting revenue deficiency be made up by other rate payers in whole or in part?
5. If so, how should the amount of the resulting revenue deficiency be calculated?
6. If so, can the resulting revenue deficiency lawfully be allocated between ratepayers and Ameren Missouri's shareholders?
i. How should the revenue deficiency allocated to other ratepayers be allocated on an interclass basis?
ii. How should the revenue deficiency allocated to other ratepayers be allocated on an intra-class basis?
7. If so, what, if any conditions or commitments should the Commission require of Noranda?

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302 Non-Unanimous Stipulation and Agreement Regarding Class Kilowatt-Hours, Revenues and Billing Determinants, Net Base Energy Costs, and Fuel Adjustment Clause Tariff Sheets, filed on March 5, 2015, Paragraph 7.

E. What is Ameren Missouri's variable cost of service to Noranda?

1. Should this quantification of variable cost be offset by an allowance for Off-System Sales Margin Revenue?

2. What revenue benefit or detriment does the Ameren Missouri system receive from provision of service to Noranda at a rate of $32.50/MWh?

F. Should Noranda be served at a rate materially different than Ameren Missouri's fully distributed cost to serve them? If so, at what rate?

G. Is it appropriate to remove Noranda as a retail customer as proposed by Ameren Missouri in its Rebuttal Testimony?

1. Can the Commission cancel the Certificate of Convenience and Necessity that was granted for Ameren Missouri to provide service to Noranda and, if so, would the cancellation of the CCN be in the public interests?

2. Can the Commission grant Ameren Missouri's proposal since notification regarding the impact of this proposal on its other customers' bills was not provided to Ameren Missouri's customers?

3. If the Commission grants Ameren Missouri's proposal, should the costs and revenues flow through the FAC?

4. Can Ameren Missouri and Noranda end their current contract without approval of all of the parties to the Unanimous Stipulation and Agreement in the case in which Ameren Missouri was granted the CCN to serve Noranda?

The parties identified many decision points related to Noranda Aluminum's request to receive a rate less than Ameren Missouri's fully distributed cost to serve it. While most of those decision points will need to be addressed, the Commission finds that the entire issue should be addressed as a single issue rather than as several sub-issues.

Findings of Fact:

1. Noranda Aluminum, Inc. operates an aluminum smelter in New Madrid, Missouri, that takes electric service from Ameren Missouri. The smelter has been in operation since 1971 and annually produces approximately 260,000 metric tonnes of aluminum. That amounts to approximately 0.5 percent of the world's aluminum production and about 5 percent of the United States' aluminum production.[303] It employs approximately 900 workers.

[303] Boyles Direct, Ex. 600, Page 4, Lines 1-14.

2. Noranda uses approximately 4.2 million MegaWatt Hours (MWh) of electricity from Ameren Missouri in a year to make aluminum. Noranda uses 480 MWs of power, 24 hours per day, 7 days per week, 52 weeks per year. Every dollar per MWh change in Ameren Missouri's electricity rate represents a $4.2 million change in the pre-tax cash flow of Noranda.[304]

3. If Noranda were to close, the Missouri economy would forego approximately $9 billion in economic activity over the next twenty-five years. State and local tax revenue would be reduced by approximately $350 million over those same twenty-five years. Additional unemployment benefits resulting from the closure could be as high as $9.4 million.[305]

4. Noranda also has a tremendous positive impact on the Southeast region of Missouri, one of the poorest regions in the country, providing the few high paying jobs in the area.

5. Noranda is by far Ameren Missouri's largest customer, representing over ten percent of the total retail sales made by the utility.[306]

6. Noranda's current average base rate is $37.95 per MWh. It is also subject to operation of the FAC. Adding the current FAC of $4.40 brings the total rate to $42.35 per MWh.[307] Noranda's current rate is based on Ameren Missouri's fully allocated cost of service.

7. At the start of this case, Noranda proposed that it be given an initial total rate

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[304] Boyles Direct, Ex. 600, Page 8, Lines 16-20.

[305] Haslag Direct, Ex. 606, Pages 4-5, Lines 11-24, 1-16.

[306] Wills Amended Rebuttal, Ex. 53, Page 17, Lines 22-23.

[307] Brubaker Direct, Ex. 503, Page 40, Lines 1-9.

of $32.50 per MWh, to be increased by one percent annually, with that rate structure to remain in place for seven years.[308]

8. On March 9, 2015, just before this issue was heard, several consumer parties joined with Noranda in a non-unanimous stipulation and agreement.[309] Among other things, that stipulation and agreement would set the base rate for Noranda at $34.00 per MWh, would exempt Noranda from operation of the FAC, and would increase Noranda's future rates by half of the percentage increase that Ameren Missouri might obtain in any future rate case. Under the stipulation and agreement, that rate structure would remain in place for ten years.

9. Several parties objected to the stipulation and agreement, and according to the Commission's rule, the stipulation and agreement cannot be approved if any party objects to it. However, the stipulated position may remain the joint position of the parties that signed the stipulation and agreement. The Commission can approve that position if it finds that it is supported by competent and substantial evidence.[310]

10. The first step to determining whether either of the reduced rates proposed by Noranda is reasonable is to determine Ameren Missouri's incremental cost to serve Noranda. The experts also refer to incremental cost as Ameren Missouri's avoided cost, meaning the cost that Ameren Missouri would avoid if the Noranda smelter shuts down.[311] Either term means the point at which other ratepayers would benefit from Noranda's presence on the system. At any price above that point, Noranda is making a contribution

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[308] Boyles Direct, Ex. 600, Page 3, Lines 9-13.

[309] The parties that signed the stipulation and agreement were Public Counsel, Noranda, Consumers Council, the Missouri Retailers Association, and MIEC.

[310] 4 CSR 240-2.115(2)(D).

[311] Transcript, Page 2792, Lines 23-25.

to Ameren Missouri's fixed costs.[312] At a price below that point, Noranda would not be making a contribution to Ameren Missouri's fixed costs and Ameren Missouri's other ratepayers would be better off without Noranda on the system.[313]

11. Incremental cost is largely influenced by the amount at which Ameren Missouri could sell power on the open market if it could no longer sell that power to Noranda.[314] MIEC's witness, James Dauphinais, testified that the incremental cost would be between \$28.03 and \$29.39 per MWh.[315] Staff's witness, Sarah Kliethermes, calculated incremental cost at \$31.50 per MWh.[316] In his rebuttal testimony, Ameren Missouri's witness, Matt Michels, calculated that point at either \$32.77 per MWh or \$34.13 per MWh.[317] At the hearing, he testified that for the period through May of 2017, the incremental cost would likely remain below \$32.50 per MWh.[318]

11. The actual future incremental cost is uncertain because it depends on the spot energy market prices and annual capacity market prices that will occur in the future.[319] 12. In setting a rate for Noranda, it is important that the rate be set, and remain, above the incremental cost. Below that cost, Noranda would not be covering any part of Ameren Missouri's fixed costs. If Noranda is not making any contribution to fixed

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[312] Transcript, Page 2793, Lines 11-19.

[313] Transcript, Page 2793, Lines 7-10.

[314] Dauphinais Direct, Ex. 508, Page 16, Lines 13-23.

[315] Dauphinais Direct, Ex. 508, Page 17, Lines 20-23.

[316] Transcript, Page 3003, Lines 14-22.

[317] Michels Amended Rebuttal, Ex. 26, Page 26, Lines 3-12. In his testimony, Michels describes those numbers as the Actual Net Energy Cost, or ANEC. At the hearing explained that ANEC is another name for incremental cost or avoided cost. See Transcript, Pages 2956-2957, Lines 22-25, 1-6.

[318] Transcript, Page 2946, Lines 10-18.

[319] Dauphinais Surrebuttal, Ex. 509, Page 25, Lines 14-18.

costs, there is no justification for allowing it to pay a reduced rate and other ratepayers would be better off if the smelter closed. But, so long as Noranda's rate remains above the incremental cost, Noranda will make a contribution to Ameren Missouri's fixed costs and other customers will pay a lower rate than they would if the smelter closed and went off Ameren Missouri's system.[320]

13. A rate below fully allocated cost of service and above incremental cost of service is only appropriate if the smelter will likely leave Ameren Missouri's system if not allowed a lower electric rate. The future viability of the smelter, and thus the likelihood Ameren Missouri would retain Noranda's load, is largely dependent on the price of aluminum metal on the world market.[321]

14. The world's aluminum price is established by trading on the London Metal Exchange (LME), which includes a U.S. Midwest premium applicable to the aluminum produced at the Noranda smelter.[322]

15. The price of aluminum is highly volatile. Over the last 30 years, the annual percentage changes in price vary from plus 44 percent to minus 33 percent. Large positive changes can be quickly followed by large negative changes. On the whole, the average annual percentage of change in price per year is 15.9 percent.[323] Removing the effect of general inflation, aluminum prices have trended downward since 1982 by an average of 0.3 percent per year.[324]

16. Demand for aluminum tends to be cyclical following the general business

[320] Transcript, Page 3003, Lines 4-13.

[321] Fayne Surrebuttal, Ex. 603, Pages 4-5, Lines 9-22, 1-12.

[322] Pratt Direct, Ex. 608, Page 3, Lines 5-12.

[323] Pratt Direct, Ex. 608, Page 3, Lines 18-24.

[324] Pratt Direct, Ex. 608, Page 5, Lines 5-7.

cycle and is concentrated in industrial sectors that experience large swings in demand. Swings in demand are amplified by an inventory cycle.[325]

17. The other side of the pricing equation, supply, tends to be inelastic because production capacity cannot be increased in the short term. Occasionally that results in large upward spikes in price. But more commonly supply is unresponsive on the downside. Aluminum smelters need to work at full capacity to minimize costs so small adjustments in production are not practical. So producers tend to keep producing even when demand falls, causing inventories to grow and prices to fall.[326]

18. The demand for aluminum is also affected by major price shocks caused by the effects of financial crises, wars, or other major world events. Such crises are certain to occur, but their timing is unpredictable.[327] As a result, forecasts of future aluminum prices can be unreliable.[328] There is little ability to predict the timing of an aluminum cycle beyond a year or two, and even a short-term prediction can be significantly wrong.[329]

19. To test its ability to survive the volatility of the aluminum market, Noranda ran several scenarios to "stress test" the smelter's ability to survive. Based on those scenarios, Noranda believes that at some point, unless it receives a lower electric rate, it will exhaust its available credit and cash and will not be able to attract new investment. At that time, it will face a "substantial likelihood of imminent closure."[330]

20. Ameren Missouri criticized the scenarios chosen by Noranda as

[325] Pratt Direct, Ex. 608, Pages 6-7, Lines 15-16, 1-13.

[326] Pratt Direct, Ex. 608, Page 7-8, Lines 15-26, 1-10.

[327] Pratt Direct, Ex. 608, Pages 9-10, Lines 1-14, 1-2.

[328] Pratt Direct, Ex. 608, Pages 16-20.

[329] Pratt Surrebuttal, Ex. 609, Page 6, Lines 1-4.

[330] Boyles Direct, Ex. 600, Page 20, Lines 4-11. See also, Boyles Surrebuttal, Ex. 601, Page 9, Lines 5-23.

unrepresentative of the most likely aluminum price forecasts. For example, if Noranda had used the future aluminum prices forecasted by CRU, a commodity sector consultancy, based in London[331] in its scenarios, it would not face a liquidity shortage.[332]

21. However, the scenarios are not intended to be forecasts of likely aluminum prices. Rather they are scenarios of what could happen to the smelter if certain aluminum prices develop.[333] And there is a substantial possibility of encountering a significant price downturn in at least one of the next six years. Such a downturn of at least 14.7 percent has occurred in every six-year period since 1982.[334]

22. Experts do rely on scenarios such as these to stress test business plans, assess ability to service loans, and assess ability to pay for power.[335] More importantly, lenders also use such stress testing to determine whether to loan money to a company. Banks and institutional lenders look at scenarios that use conservative forecasts when determining whether it is safe to loan money to a borrower.[336]

23. And the need to consider the views of lenders is important because Noranda will need to refinance substantial amounts of debt in the near future. Noranda's revolving asset based loan facility allows the company to obtain cash to run its day to day business operations. It will need to be refinanced in February 2017.[337] In addition, Noranda has a large amount of existing debt that comes due in 2019, which it will need to start refinancing

[331] Humphreys Rebuttal, Ex. 19, Page 3, Lines 8-9.
[332] Mudge Rebuttal, Ex. 33, Page 17, Lines 1-7.
[333] Pratt Surrebuttal, Ex. 609, Page 6, Lines 14-22.
[334] Pratt Surrebuttal, Ex. 609, Page 7, Lines 14-21.
[335] Pratt Surrebuttal, Ex. 609, Page 8, Lines 1-11.
[336] Harris Surrebuttal, Ex. 605, Page 2, Lines 4-23.
[337] Boyles Direct, Ex. 600, Page 21, Lines 17-22.

in 2018.[338]

24. Steven Schwartz, an economist who testified for Noranda, explained that Noranda's operating performance in 2015 and expectations about 2016 will "color the way that potential lenders evaluate Noranda."[339] Schwartz further explained: "Creditors will lend Noranda money if its prospects seem likely to improve. Absent prospects for improvement, however, Noranda is an unattractive borrower."[340] If it is to improve its prospects, Noranda immediately needs a lower electric rate to improve its cash flow.

25. Noranda's refinancing difficulties are not just theoretical. Noranda has already been unable to obtain financing for construction of a new rod mill at the New Madrid smelter, causing a further drain on its cash resources.[341]

26. Tom Harris, a banker specializing in leverage finance for corporations, testified for Noranda that based upon his experience as a banker and leveraged financier, "Noranda will be unable to raise capital without first fundamentally improving its cash flow and thereby demonstrating its long-term viability".[342]

27. Noranda is heavily in debt. Its current leverage ratio is nearly seven times its last twelve-months' earnings.[343] Its debt to equity ratio was at 87 percent at the end of 2013.[344] Moody's and Standard & Poors have recently downgraded Noranda's credit

[338] Boyles Direct, Ex. 600, Page 22, Lines 20-23.

[339] Schwartz Direct, Ex. 610, Page 17, Lines 19-23.

[340] Schwartz, Direct, Ex. 610, Page 17, Lines 13-15.

[341] Harris Direct, Ex. 604, Page 3, Lines 13-22.

[342] Harris Direct, Ex. 604, Page 5, Lines 4-14.

[343] Harris Direct, Ex. 604, Page 5, lines 16-21.

[344] Mudge Rebuttal, Ex. 33, Page 37, Lines 8-9.

rating to a "highly speculative" grade of risk.[345]

28. In large part, Noranda's current financial plight is due to its heavy debt load, much of which was imposed upon it when it was acquired by Apollo, a private equity firm, in a leveraged buyout transaction in 2007. Apollo borrowed funds to buy Noranda, using the company's assets as collateral. It then used Noranda's assets to borrow more money to recoup its equity investment in the company and to pay itself additional dividends.[346]

29. Apollo no longer is the sole owner of Noranda. It is now a publicly traded company, although Apollo continues to own a third of its outstanding shares.[347]

30. Electricity is Noranda's largest single cost to make aluminum, comprising 31.8 percent of the total cost.[348] However, electricity is not the only cost to produce electricity, and Noranda has advantages over some other smelters for those costs.[349] If Noranda was granted the $32.50 rate it originally requested, it would have the lowest total production cost of any aluminum producer in the country.[350]

31. A chart prepared by Noranda witness, Henry Fayne, from data provided by CRU, shows that Noranda's current cost of electricity, at $42.50 per MWh, is the second highest among the nine remaining smelters in the United States. At a rate of $34 per MWh as proposed in the joint position, its rate would drop to the second lowest in the country.

Conclusions of Law:

A. Commission Rule 4 CSR 240-2.115(2)(D) states:

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345 Boyles Direct, Ex. 600, Page 23, Lines 10-13.

346 Mudge Rebuttal, Ex. 33, Pages 36-37, Lines 7-18, 1-9.

347 Transcript, Page 2436, Lines 15-25.

348 Schwartz Direct, Ex. 610, Page 8, lines 7-17.

349 Mudge Rebuttal, Ex. 33, Page 49, Lines 8-19.

350 Mudge Rebuttal, Ex. 33, Page 54, Lines 1-3.

> A nonunanimous stipulation and agreement to which a timely objection has been filed shall be considered to be merely a position of the signatory parties to the stipulated position, except that no party shall be bound by it. All issues shall remain for determination after hearing.

B. Section 393.130, RSMo (Cum. Supp. 2013), establishes the requirements for the provision of service by regulated utilities. In general, it requires that all charges for utility service must be "just and reasonable" and not more than allowed by law or order of this Commission. Subsection 2 of that statute further states:

> No … electrical corporation … shall directly or indirectly by any special rate, rebate, drawback or other device or method, charge, demand collect or receive from any person or corporation a greater or less compensation for … electricity …, except as authorized in this chapter, than it charges, demands, collects or receives from any other person or corporation for doing a like and contemporaneous service with respect thereto under the same or substantially similar circumstances or conditions.

Subsection 3 adds:

> No … electrical corporation … shall make or grant any undue or unreasonable preference or advantage to any person, corporation or locality, or to any particular description of service in any respect whatsoever, or subject any particular person, corporation or locality or any particular description of service to any undue or unreasonable prejudice or disadvantage in any respect whatsoever.

C. In sum, the statute says that utilities cannot give any "undue or unreasonable" preference to any particular customer, or class of customers. The most cited case interpreting the meaning of "undue or unreasonable" preference is *State ex rel. Laundry v. Public Service Commission*,[351] a 1931 decision by the Missouri Supreme Court. The *Laundry* decision arose from a complaint brought before the Commission by two laundry companies contending that they should be allowed to receive water service at the same reduced rate made available to ten manufacturing customers. The court found that the

[351] 34 S.W.2d 37 (Mo 1931)

special manufacturing rate had been put in place by the utility to try to draw more business into its service area. In its decision, the Supreme Court found that the laundries were similarly situated to the manufacturing customers and should have been allowed to take water at the reduced manufacturer's rate.

D. The *Laundry* decision merely decides that in the facts described in that case, the laundries should have qualified for the industrial rate. As a result, the Laundry court's views of economic development rates are largely dicta. However, Ameren Missouri cites to an even earlier Commission decision that the *Laundry* court quoted extensively for the proposition that all economic development rates are forbidden by the controlling statute. That Commission decision, *Civic League of St. Louis v. City of St. Louis*,[352] does indeed sharply criticize a water rate imposed by the City of St. Louis for the purpose of encouraging manufacturing enterprises to locate within the city and orders the city to revise those rates to avoid discrimination. However, the criticism was that the rates imposed by the City of St. Louis were set below the cost of service and that they were unreasonably low. In the words of that Commission:

> The establishment of the truth of such averment (that rates to manufacturers were below the cost of service) would reveal not only unquestionably unjust discrimination, but also an unreasonable low rate to this class (the manufacturers), and intolerable oppression upon the general metered water users in that they would be compelled to pay in part for water and service furnished to the favored class. The exercise of power crystallized into legislation that unjustly discriminates between users of water in this manner, in effect deprives those discriminated against of the use of their property without adequate compensation or due process of law, and turns it over to the favored class. It is in essence a species of taxation which takes the private property of the general or public metered water users for the private use of metered water users engaged in manufacturing. This is an abuse of power.[353]

[352] 4 Mo. P.S.C. 412 (1916).

[353] *Civic League* at 455-456.

While this decision speaks more directly to the propriety of below-cost rates, it does not necessarily contradict the principle set forth in *Laundry* that the Commission may set preferential rates as long as the preference is reasonably related to the cost of service and is not unduly or unreasonably preferential.[354] No party has identified any subsequent court decision that would go as far as proscribing all economic development or load retention type rates.

E. Instead, the courts that have examined this issue have made fact-based inquiries about the statutory proscription against unjust and unreasonable rates and undue or unreasonable preference or disadvantage and this is what the Commission must do here.[355]

F. The evidence in this case shows that Noranda is a unique customer because it uses much more electricity than any other Ameren Missouri customer. It uses that electricity at a very high load factor. It is so unique that it has had its own rate classification for many years. G. Under these circumstances, a rate for Noranda that is less than its fully allocated cost[356], but more than its incremental cost is just and reasonable within the meaning of Section 393.130, RSMo (Cum. Supp. 2013), and is not unduly or unreasonably preferential.

Decision:

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[354] ". . . that principle of equality does forbid any difference in charge which is not based upon difference in service, and, even when based upon difference of service, must have some reasonable relation to the amount of difference, and cannot be so great as to produce an unjust discrimination." *Laundry* at 45.

[355] *For example see, State ex rel. City of Joplin v. Pub. Serv. Comm'n,* 186 S.W.3d 290 (Mo. App. W.D. 2005).

[356] Ameren Missouri's fully allocated cost to serve Noranda would include an allocation of all fixed and variable costs. Noranda's current rate represents its fully allocated cost of service.

The Commission will start from a premise that no one really disputes; Noranda is significant to this state, to Ameren Missouri, and to its customers. Noranda's aluminum smelter near New Madrid, Missouri has a huge economic impact on a region of the state, known as the Bootheel, that is economically depressed. It buys staggeringly large amounts of electricity every hour of every day. It is by far Ameren Missouri's largest customer, by itself buying over ten percent of all the electricity Ameren Missouri sells. For many years, Noranda has come before this Commission in every Ameren Missouri rate case and proclaimed that it needs low cost electricity to remain viable. Sometimes the Commission has made decisions that Noranda would find favorable; sometimes it has not. Most recently, less than a year ago, the Commission denied Noranda's request for a reduced rate in a complaint case decided while this case was pending. The Commission denied that request because Noranda failed to meet its burden of proof to show that its current rate was not just and reasonable. But Noranda continued its quest for a lower rate in this rate case, again asking for a rate that is below Ameren Missouri's fully allocated cost to serve. This time the Commission reaches a different result because additional evidence and argument was presented. The additional evidence describes a looming problem for Noranda: it must seek to refinance its existing debt in 2017 and 2019. Noranda presented various scenarios based on the price of aluminum in which it would run out of liquidity (cash and available credit) in the next few years. Those scenarios were criticized a not the most likely to occur, and indeed, they are not intended to be forecasts of aluminum prices. Rather, they are scenarios of what would happen if aluminum prices, which are volatile, were to drop. They are worst case scenarios, but sometimes the worst happens.

Lenders do not look at a borrower and accept promises that everything will be alright if aluminum prices stay as high as the analysts think they will. Investors asked to loan millions of dollars to Noranda will want to know whether the company will be able to survive and pay back its debts even if things do not go as well as planned. Therefore, lenders will stress test the company by looking at unfavorable scenarios. Wall Street agrees that Noranda has a problem as the company's credit rating was recently downgraded to a highly speculative grade of risk. Unless Noranda's cash flow improves, it will likely be unable to refinance its debt and could be forced to close.

In this case, Noranda and the other parties presented evidence sufficient to convince the Commission that Noranda is in danger of discontinuing operations at its New Madrid smelter in the absence of a load retention rate. As a result, it is in the interest of all ratepayers for the Commission to allow Noranda a lower rate to keep it as a customer of Ameren Missouri.

In part, Noranda's precarious financial situation is the result of Apollo Management's decision to milk massive amounts of cash out of the company when it purchased it in 2007. Certainly, Noranda would be better off today if it still had the hundreds of millions of dollars that Apollo borrowed against the assets of the company to give to itself as a special dividend. Apollo no longer owns all the shares of Noranda, but it still owns a third of its shares and can influence its board of directors.

The Commission is not tasked with protecting private interests, and it does not want to reward Apollo's behavior in any way, but it must protect the public interest and set just and reasonable rates. In these circumstances, the public interest encompasses more than the economic concerns of Noranda's employees, the Bootheel, or even the state of

Missouri. Specifically, and of greatest import to this Commission's mandate, is the effect of Noranda's closure on Ameren Missouri's other customers. It is important to understand that a customer in St. Louis who has no connection to the Bootheel, will pay higher electric rates if Noranda closes its smelter. Right now, Noranda pays a large portion of Ameren Missouri's fixed costs, costs that will not go away just because Noranda no longer buys electricity. If Noranda closes its smelter, those costs will still be there, but then all Ameren Missouri's other customers will have to pick up the bill for those fixed costs. Thus, Ameren Missouri's other customers will benefit from retaining Noranda's load for Ameren Missouri.

As with everything else involving Noranda, the numbers are large. Noranda argues that the incremental cost to provide power to Noranda, that is the price at which Ameren Missouri could sell that power on the off-system market, is approximately $28 per MWh. If Noranda pays a rate of $36 per MWh and buys 4 million MWhs per year, it would contribute roughly $32 million per year towards Ameren Missouri's fixed costs. That is $32 million per year that Ameren Missouri's other customers will have to pay if the smelter shuts down. Even if it is assumed that the incremental cost is $31.50 per MWh as estimated by Staff, Noranda would still be contributing $18 million per year to Ameren Missouri's fixed costs at a rate of $36 per MWh. It is true Ameren Missouri's other customers will have to pay extra to make up for the lower rate given to Noranda. But they will have to pay even more if the smelter shuts down and Noranda contributes nothing to Ameren Missouri's fixed costs.

During the hearing, Noranda and several consumer groups, including the Public Counsel, filed a non-unanimous stipulation and agreement to which several parties objected. Because the stipulation and agreement is not unanimous, the Commission cannot approve it. However, the stipulation and agreement remains the joint position of the signatory parties and the Commission can use it as a starting point toward crafting a revised rate for Noranda.

The non-unanimous stipulation and agreement - now the joint position - has some good features, but the Commission is not willing to adopt that position in its entirety. First, the $34 per MWh rate proposed is too low. The Commission wants to ensure that Noranda remains competitive with other smelters in this country but does not want to require other customers to support a rate for Noranda that would make it the lowest overall cost smelter in the country.

Second, the ten-year term of the joint position is too long, and is largely illusory. Ten years is a very long time, and the market for electricity may look very different by that time. Attempting to set a rate at that distance, even with escalator clauses and opt-out measures, would not be prudent. Additionally, while a stipulation and agreement can be binding on its signatories for ten years, the Commission cannot bind future Commissions, nor can it preclude future litigants from presenting contrary positions in future rate cases, positions to which the Commission will need to give due consideration.

Since the Commission cannot, and will not, approve the joint position in its entirety, it will need to explain in detail the rate that will be established for service to Noranda:

1. For a period of three years, a new class of Ameren Missouri electric service ratepayer is authorized for Industrial Aluminum Smelters (IAS).
2. The existing tariff and rates for the LTS class will remain in effect and will be updated in this and future rate cases. If Noranda is not willing to accept the terms of service for the IAS class, or if it violates the conditions

set forth in this order, it shall revert to the LTS class.

3. An effective base rate of $36.00 per MWh is set for the IAS class, to become effective when new rates go into effect resulting from this case.
4. The new IAS class shall remain subject to the Rider FAC, but any increase in rates due to operation of the Rider FAC shall not exceed $2.00 per MWh.
5. The IAS class will not be subject to any rate increase resulting from this case.
6. If Ameren Missouri files any additional rate cases during the three-year existence of the IAS class, it is the intent of this Commission that the IAS class shall receive 50 percent of the system average increase and zero percent of any system average decrease resulting from such rate cases. When the FAC is rebased in such rate proceeding, the IAS shall once again be subject to no more than a $2.00 per MWh rate increase due to the Rider FAC. The intent of this Commission is not binding on a future Commission, and such future Commission must decide those cases based on the competent and substantial evidence presented in those cases.
7. The IAS class may retain its existence and rate after the expiration of the three-year term until such time as the Commission establishes a new rate in a general rate proceeding.
8. The IAS class shall be subject to 100 percent of any new surcharge, adjustment mechanism, or any other mechanism that seeks to change or

impose new rates between rate cases that takes effect during the three-year term as a result of any new Missouri legislation passed and taking effect after the implementation date of rates resulting from this case.

9. The new IAS class shall not be subject to charges, rates, or surcharges that were not in effect at the implementation date of rates resulting from this case unless specifically enumerated in this order.

10. The resulting deficiency in retail base rate revenue associated with the creation of the IAS class shall be applied among all remaining classes paying for Ameren Missouri's electric service by changing base rate revenue in proportion to current base rate revenue minus LTS base rate revenue. Any change in FAC revenues associated with the rate for the IAS class shall flow automatically through the FAC to all remaining classes paying for Ameren Missouri's electric service.

11. As a condition to access the reduced rate structure available to the IAS class, the IAS customer shall provide the Commission's Staff and all parties to this rate case the following information regarding employment at the New Madrid smelter:

    The IAS customer shall file a monthly certification of compliance and quarterly surveillance reports demonstrating that the customer has fulfilled the requirement that employment at the New Madrid smelter meets or exceeds a daily average of 850 full-time equivalent personnel, either direct employees or contract personnel, and specifically noting instances where the employee count goes below the required average because employees have voluntarily left the customer’s employ and the IAS customer is actively seeking to fill those positions, or due to *force majeure* or other events considered by the Commission to be outside the IAS customer’s control.

The information provided shall be classified as Highly Confidential.

12. As a condition to access the reduced rate structure available to the new IAS class, and the limited exemption from the FAC, the IAS customer shall expend $35 million in capital, as defined by accounting principles generally accepted in the United States (USGAAP), at the New Madrid smelter in the first year of the term, and shall provide the Commission Staff and all parties to this rate case an annual surveillance report, which shall be designated as Highly Confidential, detailing the nature and scope of work performed to meet the $35 million requirement with discrete expenditures accounted for by amount of capital expended.

13. As a condition to access the reduced rate structure available to the new IAS class, and the limited exemption from the FAC, after the first year of the term and through the period that the reduced base rate is in effect, the IAS customer shall expend an annual inflation adjusted $35 million in capital as defined by USGAAP at the New Madrid smelter, utilizing the general Consumer Price Index as published by the US Bureau of Labor Statistics, compounded annually, in the second through final years the reduced base rate is in effect, and a pro-rated inflation-adjusted monthly capital expenditure for each full months the reduced base rate is in effect

after the term to the extent there are any partial-year terms, and to provide the Commission Staff and all parties to this rate case an annual surveillance report, which shall be designated Highly Confidential, detailing the nature and scope of work the customer performed to meet the required aggregate capital investment level with discrete expenditures accounted for by amount of capital expended.

14. The IAS customer may elect to invest an amount greater than $35 million in capital per year, as defined above, as set forth in paragraphs 12 and 13, with a corresponding reduction in its capital spending obligation in the later years of this period, but in no event shall the IAS customer's capital investment spending credited at the end of each year be less than the compounded inflation-adjusted expenditure requirement for that same period as set forth in paragraphs 12 and 13.

15. As a condition to access the reduced rate structure available to the IAS class, and the limited exemption from the FAC, the IAS customer shall not issue any special dividend, aside from its regular, customary penny per share dividend, until after the first rate case following the expiration of the three-year term.

16. The IAS customer may remain in the IAS class only so long as it remains a stand-alone entity. Membership in the IAS class shall not be assigned to, or assumed by, any successor company, whether through direct ownership, through a holding company, or otherwise unless such assignment or assumption is approved by the Commission.

17. If the IAS customer believes that it will have to discontinue operations at the New Madrid smelter, it shall provide notice to the Commission and to all parties to this case without delay and as soon as reasonably possible.

18. As a term of the IAS tariff, if the IAS customer should materially fail – as determined by the Commission – to comply with any term or condition required to access the reduced rate provided by this order, the IAS customer shall no longer have access to the rate structure outlined herein, and the customer's rate structure shall revert to the rate structure set for the LTS class at that time, with the resulting difference in retail revenue to be allocated to the benefit of the remaining customer classes in equal proportion to their then-current contribution to retail revenue less the LTS class. Since Ameren Missouri's rates to other customers cannot be changed except through a general rate case, Ameren Missouri shall retain the extra payments collected from Noranda in that event in a regulatory liability to be returned to customers with interest in Ameren Missouri's next general rate case.

19. The Commission Staff or any party to this case may file a petition asking the Commission to determine whether the IAS customer has failed materially to comply with any term or condition required to access the reduced rate structure. Upon the filing of such a petition, the Commission shall hold a hearing or make a determination based on verified pleading within 30 days of the filing of the petition.

20. At such a hearing, the IAS customer shall bear the burden to show that it

has not failed to meet any term or condition required to access the IAS class rate structure; why its failure to meet any term or condition required to access the IAS class rate structure is immaterial; or why it should continue to access the IAS class rate structure despite a material failure to meet any term or condition required to access the IAS class rate structure.

21. In assessing whether a violation of any term or condition is material, the Commission shall weigh all relevant factors, including:

    (a) Any evidence of *force majeure*;

    (b) With regard to an alleged violation of an employment level condition, whether the violation is the *de minimis* result of the quarterly-average calculation and whether the IAS customer has actively sought, or is actively seeking, to fill those vacant positions.

In future rate cases, the Commission will once again assess whether Noranda should be allowed to continue to receive a reduced load retention rate, and may continue this rate and these conditions as it finds appropriate based on the competent and substantial evidence presented in such cases, including the economic conditions at the time of that case. In such future rate case, the Commission would consider extending the term of the special rate with additional conditions and consumer protections, including a possible price trigger based on aluminum prices on the London Metals Exchange.

THE COMMISSION ORDERS THAT:

1. The tariff sheets filed by Union Electric Company, d/b/a Ameren Missouri on July 3, 2014, and assigned tariff number YE-2015-0003, are rejected.

2. Union Electric Company, d/b/a Ameren Missouri is authorized to file a tariff sufficient to recover revenues as determined by the Commission in this order.

3. Union Electric Company, d/b/a Ameren Missouri shall file the information required by Section 393.275.1, RSMo 2000, and Commission Rule 4 CSR 240-10.060 no later than May 15, 2015.

4. The Department of Economic Development's Petition for Leave to File Amicus Brief is denied.

5. This report and order shall become effective on May 12, 2015.

BY THE COMMISSION

Morris L Woodruff

Morris L. Woodruff
Secretary

R. Kenney, Chm., W. Kenney, Hall, and
Rupp, CC., concur;
Stoll, C., dissents, with separate dissenting opinion attached.

Dated at Jefferson City, Missouri,
on this 29th day of April, 2015.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 101

(Docket No. RM04-12-000; Order No. 668)

Accounting and Financial Reporting for Public Utilities Including RTOs

(Issued December 16, 2005)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations to update the accounting requirements for public utilities and licensees, including independent system operators and regional transmission organizations (collectively referred to as RTOs). The Commission is also amending its financial reporting requirements for the quarterly and annual financial reporting forms for these entities. These updates to the Commission's Uniform System of Accounts and the financial reporting requirements will allow for better comparability between public utilities and will result in improved transparency of financial information and will facilitate better understanding of RTO costs.

EFFECTIVE DATE: The amended regulations will become effective **[insert date 30 days after publication in the FEDERAL REGISTER]**, with the accounting and financial reporting changes and updates to become effective January 1, 2006.

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SUPPLEMENTAL INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Accounting and Financial Reporting for Public Utilities Including RTOs

Docket No. RM04-12-000

ORDER NO. 668

FINAL RULE

I. Introduction

1. In this Final Rule, the Commission is revising its Uniform System of Accounts (USofA)[1] to accommodate the restructuring changes that are occurring in the electric industry due to the availability of open-access transmission service and increasing competition in wholesale bulk power markets. Corresponding changes are being made to the FERC Form No. 1, Annual Report for Major Electric Utilities, Licensees and Others (Form 1); FERC Form No. 1-F, Annual Report for Nonmajor Public Utilities and Licensees (Form 1-F); and FERC Form No. 3-Q, Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies (Form 3-Q).

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[1] 18 CFR Part 101.

II. Background

2. In April 1996, in Order No. 888,[2] the Commission established the foundation necessary to develop competitive bulk power markets in the United States: non-discriminatory open access transmission services by public utilities and standard cost recovery rules to provide a fair transition to competitive markets. Public utilities were also required to functionally unbundle, and to provide transmission service separately from generation services.

3. Despite the changes brought about by Order No. 888, reports of discriminatory practices by vertically integrated public utilities persisted. In Order No. 2000,[3] the Commission encouraged the formation of independent and regional organizations, to remedy undue discrimination and to foster regional efficiencies and efficient pricing. As a result, a number of independent system operators and regional transmission

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[2] See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 FR 12,274 (March 14, 1977), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group, v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[3] See Regional Transmission Organizations, Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 FR 12,088 (March 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), affirmed sub nom. Public Utility District No. 1 of Snohomish County, Washington, v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

organizations (collectively referred to as RTOs) have formed and are in operation.[4] These RTOs perform many of the same activities previously performed by the transmission owners whose transmission systems they now operationally control. In addition, RTOs perform some unique functions, not traditionally performed by other public utilities, they oversee markets and they conduct long-term system planning on a regional basis.

4. On September 26, 2004, the Commission issued a Notice of Inquiry (NOI) in this proceeding.[5] The NOI invited comments on various matters including the Commission's accounting and financial reporting requirements for RTOs. The Commission received comments from RTOs, public utilities that are RTO members, state regulatory commissions, and others. Generally, commenters agreed that the existing accounting regulations and related financial reporting requirements do not provide sufficient detailed information about RTO-related costs, including the costs incurred by RTOs and other relevant information concerning the types of services RTOs provide to their members. On June 3, 2005, the Commission issued a Notice of Proposed Rulemaking (NOPR) in

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[4] See, e.g., the California Independent System Operator Corporation (CAISO), the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), the ISO New England, Inc. (ISO-NE), the New York Independent System Operator, Inc. (NYISO), PJM Interconnection, L.L.C. (PJM), and the Southwest Power Pool, Inc. (SPP).

[5] See Financial Reporting and Cost Accounting and Recovery Practices for Regional Transmission Organizations and Independent System Operators, 69 FR 58,112 (September 29, 2004), FERC Stats. & Regs. ¶ 35,546 (2004).

response.[6] The Commission received comments from RTOs, public utilities that are RTO members, and others.[7]

5. Today, the Commission is issuing this Final Rule to address the accounting and financial reporting issues raised in the NOPR and the comments to the NOPR. The changes to the Commission's accounting and financial reporting requirements adopted here will provide uniformity and transparency in accounting for and reporting of transactions and events affecting public utilities, including RTOs. The Commission expects that these changes in accounting and financial reporting will also lead to improvements in cost recovery practices by providing details concerning the cost of RTO functions, and increased assurance that the costs are both legitimate and reasonable costs of providing service and assigned to the correct period for recovery in rates.

III. Discussion

A. General

6. The Commission received 22 comments on the proposed accounting and reporting requirements which ranged from favorable to falling short of the proposal's intended goal of providing greater transparency for transactions and business functions. Most commenters, however, generally commend and support the Commission's proposed

[6] Accounting and Financial Reporting for Public Utilities Including RTOs, 70 FR 36865 (June 27, 2005); FERC Stats. and Regs. ¶ 32,585.

[7] See Appendix A for list of commenters.

initiative to amend its regulations to update the accounting requirements for public utilities, including RTOs.[8] After careful consideration of the comments received, the Commission is adopting the changes and revisions as proposed with certain modifications and clarifications as discussed below.

B. Regional Transmission And Market Operation Asset Function

1. Accounting NOPR

7. In the NOPR, the Commission proposed to create a new asset function entitled Regional Transmission and Market Operation Plant to record RTO investments in computer hardware, software and communication equipment.[9] The proposed new accounts in this function are Account 380, Land and Land Rights; Account 381, Structures and Improvements; Account 382, Computer Hardware; Account 383, Computer Software; Account 384, Communication Equipment; Account 385, Miscellaneous Regional Transmission and Market Operation Plant; Account 386, Asset Retirement Costs for Regional Transmission and Market Operation Plant; and reserves Account 387 for future accounts.

2. Commenters

8. Commenters were generally supportive and did not oppose the creation of the Regional Transmission and Market Operation Asset Function. One commenter

[8] See generally National Grid, NRECA, Indicated NYTOs, and TANC.

[9] NOPR at P 20-32.

recommended breaking down each new asset account into sub-accounts for general purpose activities, market design development, and market operation.[10]

3. Commission Conclusion

9. The Commission will adopt the Regional Transmission and Market Operation Asset Function as proposed in the NOPR: Account 380, Land and Land Rights; Account 381, Structures and Improvements; Account 382, Computer Hardware; Account 383, Computer Software; Account 384, Communication Equipment; Account 385, Miscellaneous Regional Transmission and Market Operation Plant; Account 386, Asset Retirement Costs for Regional Transmission and Market Operation Plant; and reserves Account 387 for future accounts. The Commission notes that in order to perform many of their primary functions, RTOs must make significant investments in computer hardware, software and communication equipment. The cost of these assets is not explicitly addressed in the existing primary plant accounts, resulting in inconsistent accounting and reporting for these assets. In order to provide more financial transparency and consistent accounting and reporting for the costs of hardware, software and communication equipment, the Commission believes a new utility plant function is needed to record the cost of assets owned and used by RTOs.

10. The Commission does not believe sufficient justification has been advanced to expand the proposed new accounts further as suggested by commenters. The new

[10] City of Santa Clara at 23.

accounts adopted herein will provide the Commission and others with additional, more detailed information than is currently available about the major types of assets needed to perform region-wide transmission and market operations. These assets perform joint functions and at this point the Commission believes it may be unduly burdensome to allocate the costs of these assets in greater detail.

A. RTO Revenue Accounts

1. Accounting NOPR

11. Revenues RTOs receive for the reimbursement of their operational costs are not addressed in the current USofA because the existing revenue accounts were designed principally to record revenues from electricity sales on a bundled basis. Therefore, the Commission proposed the creation of two new revenue accounts to record amounts billed by RTOs to their members.[11] The first, Account 457.1, Regional Transmission Service Revenues, would include revenues received by RTOs for services provided and amounts billed under each Commission-approved tariff. The second, Account 457.2, Miscellaneous Revenues, would include revenues received from incidental transactions and events, such as profits or losses on sales of miscellaneous materials.

12. The Commission also proposes to include a new Form 1 Schedule to report the revenue collected by RTOs for services performed pursuant to Commission-approved tariffs.

[11] NOPR at P 33-35.

2. Commenters

13. Commenters are generally supportive of the proposed accounting for RTO revenue accounts.[12] However, one commenter suggests that the Commission should create a mechanism and account for all revenues and costs arising from managed market services and operations. [13]

14. Another commenter asserts that RTO constituents have the right to know how much of their RTO's revenues derive from penalties assessed by the RTO.[14] The commenter thus asserts that a new series of accounts should be created to record RTO's revenue from penalties assessed against market participants. According to the commenter, these accounts should be further augmented by another, separate new sub-account for neutrality charges assessed by the RTO.

3. Commission Conclusion

15. We will adopt Account 457.1, Regional Transmission Service Revenues, Account 457.2, Miscellaneous Revenues, and the RTO Revenue Schedule as proposed in the NOPR. The Commission declines to adopt the recommendation to amend the USofA to require RTOs to record revenues on their books and records for energy products, services and commodities associated with services that RTOs manage for market participants. In these instances, an RTO acts as an agent in providing these services; it does not realize or

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[12] See, e.g., APPA at 19, ISO/RTO Council at 2.

[13] See TANC at 12.

[14] See SVP at 20.

earn revenue on these transactions. The RTO merely collects monies from one member or participant and remits it to another member or participant. For example, when a member or participant purchases energy through an RTO managed centralized energy market, the RTO merely collects monies from the purchaser of the energy and remits it or passes it through to the appropriate energy supplier, who then records it as revenue.

16. We also decline to adopt the recommendation to amend the USofA to create separate sub-accounts of Account 457 to record penalty and neutrality revenues. According to the instructions of the new RTO revenue accounts, RTOs are to maintain records showing revenues received from customers by type of charge. RTOs then must report any penalty and neutrality revenues received on the newly-created RTO Revenue Schedule adopted herein, providing adequate disclosure of these revenues.

D. Regional Market Expense Function

1. Accounting NOPR

17. In the NOPR, the Commission explained that the current USofA does not provide sufficient financial transparency concerning the types of costs incurred by RTOs in facilitating and monitoring energy markets. In order to address this deficiency the Commission proposed creating a separate new expense function within the USofA to capture these types of costs in greater detail.[15] As part of this new function, the Commission proposed the creation of certain operating expense accounts to capture the

[15] NOPR at P 36-51.

costs of managing the various RTO markets and reviewing market data to determine compliance with market rules. These accounts are Account 575.1, Operation Supervision; Account 575.2, Day-Ahead and Real-Time Market Facilitation; Account 573.3, Transmission Rights Market Facilitation; Account 575.4, Capacity Market Facilitation; Account 575.5, Ancillary Services Market Facilitation and Account 575.6, Market Monitoring and Compliance.

18. Additionally, new accounts were proposed to capture and provide greater detail as to the amount of maintenance expense incurred on computer hardware, software, communication equipment and other assets owned and used by RTOs. These accounts are Account 576.1, Maintenance of Structures and Improvements; Account 576.2, Maintenance of Computer Hardware; Account 576.3, Maintenance of Computer Software; Account 576.4, Maintenance of Communication Equipment and Account 576.5, Maintenance of Miscellaneous and Market Operation Plant.

19. Finally, the Commission proposed that RTOs report in Form 1 the data required by the Transmission of Electricity for Others schedule[16] to provide more complete information concerning the use of the transmission system under the control of the RTO.

[16] See FERC Form 1 at 328-330.

2. **Commenters**

20. Most commenters did not object to the Commission's proposal to create a new regional market expense function.[17] However, some commenters suggest that the Commission clarify that the regional market expense function accounts apply solely to RTOs, as the proposed new regulatory text contained in the NOPR does not make this clear.[18] Additionally, one commenter suggests that the Commission change the descriptive caption of this function from "regional market operations expense" to "market operations expense."[19] This commenter submits that these accounts should not be limited to RTOs, as other public utilities in the future may use market oriented approaches to provide these services.

21. One commenter also suggests that the word "facilitation" in the title of Accounts 575.2, 575.3, 575.4 and 575.5, be changed to "administer" as RTOs administer or operate organized markets while "facilitation" describes a more passive role than is the case.[20]

22. Additionally, one commenter suggests that the Commission require RTOs to record and report revenues and expenses related to the cost of energy, energy products,

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[17] See, e.g., ISO/RTO Council at 2.

[18] See, e.g., EEI at 2.

[19] See APPA at 18.

[20] APPA at 19.

services and commodities that RTOs manage or provide to market participants.[21] Another commenter suggests that RTO customer service costs be recorded separately in a newly-created account;[22] customer service costs are a significant component of RTO expense identified by public utilities and it is important for RTO/non-RTO customer services expenses to be segregated.

23. Finally, most commenters did not object to the proposal to require RTOs to report the data required by the Form 1 Transmission of Electricity for Others schedule. However, one commenter asserts that RTOs do not currently organize transaction data in a way that would allow them to report the information called for by the schedule.[23] This commenter notes that RTOs treat most service in their footprint as network service and as such can only report aggregate flows without transaction specific source and sink information. The commenter contends that absent extremely expensive software and design changes RTOs will not able to fully report the information called for on the schedule. The commenter recommends that the Commission not include this requirement in the Final Rule or in the alternative clarify that aggregate flow data will be acceptable.

[21] TANC at 2 and SVP at 27.

[22] NRECA at 8.

[23] See ISO/RTO Council at 5.

3. Commission Conclusion

24. The Commission will adopt the regional market expense function and accounts proposed, as modified and clarified below. Upon additional consideration, the Commission clarifies that any jurisdictional entity, whether an RTO or a non-RTO public utility, must use the regional market expense accounts if a regional market expense is incurred. The key for recording costs in these accounts is not whether an entity is an RTO or not, but whether an entity is performing market services on a region-wide basis. The accounts are intended to capture costs incurred in performing region-wide services related to market administration, market monitoring and market compliance activities whether performed by an RTO or another non-RTO public utility. These accounts are not limited to RTOs, as other non-RTO jurisdictional entities may provide these market services, and the costs incurred by these other non-RTO jurisdictional entities in performing these services must be captured in these accounts. The Commission will add a definition of regional market to the USofA to make clear which type of entities are to use the regional market expense function accounts. The Commission clarifies that regional market expense accounts are to be used not only by RTO/ISO public utilities but by any public utility that operates an organized energy market, whether directly or through a contractual relationship with another entity.

25. The Commission will modify the account titles and instructions to replace the word “facilitation” with “administer”, as we agree with the commenter that it is more descriptive of the role RTOs play (and others may play) in market operations.

26. The Commission declines to adopt commenter recommendations to amend the USofA to require the RTOs to record expenses on their books and records for energy products, services and commodities associated with services that RTOs manage for market participants. As previously discussed, an RTO acts as an agent and does not take title to energy products, services and commodities associated with services in the performance of these managed services. The RTO merely collects monies from one member or participant and remits it to another member or participant.

27. The Commission also declines to adopt one commenter's suggestion to create new accounts to separately record RTO customer service costs. Our existing accounting rules contain customer service expense accounts for recording costs of this nature, Accounts 901-910 (Customer Accounts and Customer Service Accounts). RTOs are required to record their customer service expenses in the appropriate existing customer service accounts. Therefore, it is not necessary to create new accounts for this purpose.

28. One commenter asserts that RTOs cannot provide all of the information required on the Form 1 Transmission of Electricity for Others schedule absent costly software changes to their systems; most of the transmission service in their footprint is network service and as such RTOs do not currently maintain transaction specific source and sink information in a format needed to complete the schedule. However, RTOs can provide aggregate power flow information for the transmission facilities under their control.

29. We will, therefore, require RTOs to report aggregate transmission usage information for imports into the RTO from other systems, exports from the RTO, through

and out service, network service and point-to-point service. We will also require RTOs to report related financial information by type of service, such as network and point-to-point service. These changes we adopt herein will give the Commission more complete information concerning the use of the transmission system under the control of RTOs, without requiring RTOs to make costly software changes. We will require the transmission usage information to be reported on a new Form 1 and Form 3-Q schedule entitled Monthly ISO/RTO Transmission System Peak Load and the related financial information on a newly created schedule entitled Transmission of Electricity by RTOs, rather than have RTOs report the information on the Form 1 Transmission of Electricity for Others schedule which is not a good fit for reporting this aggregate information.

30. In examining the new regional market expense function, we recognize a rent account is needed to capture the expenses associated with renting assets to perform regional market functions to be consistent with our other function classifications. Therefore, we will also add a new account entitled Account 575.8, Rents, to capture rent costs in the regional market expense function.

E. Accounting by Public Utilities for Computer Hardware, Software and Communication Equipment

1. Accounting NOPR

31. In the NOPR, the Commission proposed to add three new sub-accounts to the existing transmission asset function for public utilities and licensees, other than RTOs, to record the cost of computer hardware, software and communication equipment owned

and used for transmission related activities.[24] The Commission proposed to create Account 351.1, Computer Hardware, Account 351.2, Computer Software, and Account 351.3, Communication Equipment, so as to provide uniform and consistent accounting and reporting for these types of assets by non-RTO public utilities and licensees.

2. Commenters

32. Commenters generally argue that the proposed changes would impose a significant burden on companies;[25] companies will face a complex undertaking in identifying what portions of their computer hardware, software and communications equipment and operation and maintenance costs belong in the new transmission accounts because most companies rely on such hardware, software, and equipment for multiple purposes.[26] One commenter suggests that the Commission appears to have overlooked the fact that public utilities perform many more functions than simply transmission functions.[27]

33. Commenters assert that the new accounts for computer equipment and computer use will require judgments as to disaggregation and assignment of these costs among different accounts[28] - - costs that are not necessarily severable and directly assignable.

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[24] NOPR at P 52-53.

[25] See EEI at 4, SCE at 2, FirstEnergy at 8.

[26] EEI at 9.

[27] SCE at 2.

[28] International Transmission at 5.

Commenters also assert that these allocations will be unnecessarily arbitrary and the Commission's desire for comparability will never be achieved.[29]

34. Commenters recommend that, due to the extreme burden the proposed changes would place on public utilities, these changes should be applied only to RTOs, whose sole business is related to performing transmission functions.[30] Commenters note that the RTOs' primary function is the administration of transmission systems and the use of their hardware, software and communication equipment is more easily identifiable as transmission related.[31]

35. Commenters also suggest that, if the Commission retains the proposed new computer and communication equipment accounts for use by licensees and public utilities other than RTOs, that it provide companies the flexibility to make reasonable allocations to the new accounts and other accounts in the USofA, including the general plant accounts.[32] Commenters also suggest that companies should be able to adopt the new accounts in a way that makes sense given their circumstances, with as little extra effort as possible, without having to perform complex allocations, and without having to modify prior accounting records and reports.

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[29] FirstEnergy at 17.

[30] SCE at 3.

[31] FirstEnergy at 16.

[32] EEI at 9.

36. Another commenter suggests that new sub-accounts should be set up to record the additional computer hardware, software and communications equipment required to interface with the RTO.[33] This commenter suggests that these sub-accounts should record and disclose the amount of information and technology and communications spending that relates specifically to the public utility's RTO interface.

37. Finally, one commenter also notes that the Commission proposes to add new sub-accounts to Account 569, Maintenance of Structures, namely Account 569.1, Maintenance of Computer Hardware, Account 569.2, Maintenance of Computer Software, and Account 569.3, Maintenance of Communication Equipment. The commenter suggests that the more appropriate account for these sub-accounts would be Account 573, Maintenance of Miscellaneous Transmission Plant (Major only), making them sub-accounts Account 573.1 though Account 573.3.[34]

3. Commission Conclusion

38. The great majority of commenters disagree with the NOPR's proposed accounting for computer hardware, software and communication equipment by public utilities and licensees other than RTOs. These commenters argue that these assets are not necessarily severable and directly assignable. They point out that the equipment and software in question perform many different functions and that it would be extremely difficult to

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[33] SVP at 35.

[34] EEI at 9.

determine what portion of the equipment and software perform a transmission function. These commenters also argue that individual utilities may use different allocation methods to determine the portion of these items used in transmission, which will reduce comparability among utilities and therefore the usefulness of the reported accounting information. Finally, these commenters contend that it will be burdensome and costly to implement the proposed changes and that minimal reporting benefits will be derived from the change.

39. The Commission acknowledges that some or perhaps most computer hardware, software and communication assets are joint use assets that may not be severable or directly assignable to the transmission function. We agree with commenters that requiring entities to record that portion of their investments in these assets used for transmission purposes within the transmission function on an allocated basis is problematic in that functional reclassification of the investment, as well as the related depreciation reserve, would be required each accounting period as the allocation factor changes. Therefore, we have decided not to adopt proposed Accounts 351.1, 351.2 and 351.3 for public utilities and licensees other than RTOs and will continue to allow non-RTO public utilities to account for these items as joint use assets as they have historically done. However, we will require both RTOs and non-RTO public utilities to record the costs of maintaining these assets that are related to providing transmission services in Accounts 569.1, 569.2 and 569.3 as proposed. Non-RTO public utilities already allocate these joint use costs for ratemaking purposes in determining open access transmission

rates. We will now also require that public utilities allocate these costs for accounting purposes.

40. Allocation approaches used by public utilities must ensure that a reasonable portion of the cost of maintaining these joint use assets are used in the transmission of electricity are allocated to the transmission function. Additionally, public utilities are also expected to allocate these costs to the transmission function on a consistent basis from year to year. Public utilities will be required to footnote their allocation method used to calculate these maintenance expenses as reported in the Form 1 Electric Operation and Maintenance Expenses Schedule (pages 320-323).

41. Finally, we decline to adopt one commenter's suggestion that instead of adding sub-accounts to Account 569, Maintenance of Structures, that we add sub-accounts to Account 573, maintenance of Miscellaneous Transmission Plant, for the maintenance costs related to computer hardware, software and communication equipment. The commenter provides no explanation for the proposed change and we see no benefit in deviating from the account structure originally proposed.

F. Accounting and Financial Reporting by Public Utilities, Including RTOs

1. Accounts for Load Dispatching, Scheduling and System Control Expenses

i. Accounting NOPR

42. In the NOPR, the Commission proposed to replace Account 561, Load Dispatching, with a series of detailed expense accounts to record expenses for providing

transmission services related to load dispatching, scheduling and system control.[35] The proposed accounts are Account 561.1, Load Dispatch-Reliability, to include the costs incurred to manage the region-wide reliability coordination function; Account 561.2, Load Dispatch-Monitor and Operate Transmission System, to include the costs incurred to monitor, assess and operate the transmission system and ensure the system's reliability and Account 561.3, Load Dispatch-Transmission Service and Scheduling, to include the costs incurred to process hourly, daily, weekly and monthly transmission service requests using an automated system such as an Open Access, Same-Time Information System (OASIS).

ii. <u>Commenters</u>

43. One commenter asserts that the Commission should not apply the proposed USofA changes to transmission owners that are members of an RTO or ISO, as doing so will increase the cost to consumers for the implementation of these systems, while providing little additional information to the Commission.[36] This commenter also asserts that it may be difficult to disaggregate expenses among the proposed new Load Dispatch sub-accounts (561.1, 561.2, and 561.3), because the same staff members may perform functions included under more than one of these sub-accounts, tasks undertaken to accomplish functions relevant to one sub-account may also contribute to completion of

[35] NOPR at P 54, 56-59.

[36] NYTOs at 2.

another, and the descriptions of the sub-accounts are insufficiently detailed.[37] This commenter further asserts that if the Commission does decide to apply the proposed USofA changes to utilities that are members of RTOs and ISOs, it should allow those utilities to apply for a waiver to allow consolidated reporting of load dispatch expenses if they fall below a *de minimus* threshold.[38]

44. Another commenter asserts that the lines of demarcation between costs in these sub-accounts are not clear and that the Commission should provide additional guidance on its intention as to information to be captured in these sub-accounts.[39] Yet another commenter notes that, while it supports the Commission's goal of greater cost transparency, it similarly recommends that the Commission provide further guidance so that the useful cost comparisons that the Commission is seeking to facilitate can be made across RTOs and public utilities.[40] This commenter asserts that the addition of accounts to reporting forms will be of little use if users are not populating those accounts with comparable costs and information. This commenter recommends that the Commission provide additional guidance regarding the specific information it would like captured in these sub-accounts.

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[37] Id. at 7.

[38] Id. at 10.

[39] EEI at 8.

[40] International Transmission at 3.

45. One commenter supports the specific account structure the Commission proposes, as well as its applicability to both RTOs and non-RTO public utilities. However, that commenter suggests the Commission realign the grouping of the new accounts under two new functions (system control and transmission services) that it proposes should be created.[41]

46. Finally, a commenter notes that, in the text of the NOPR's discussion of Accounts 561.1, 561.2 and 561.3, the NOPR states that these proposed accounts are for use by both non-RTO public utilities and RTOs.[42] However, in the proposed text of the USofA for Accounts 561.1, 561.2 and 561.3, the proposed language specifically states that the accounts are to include expenses incurred by the regional transmission service provider, with no mention in the proposed text of non-RTO public utilities. The commenter suggests that the Commission revise the proposed text of the USofA for proposed Accounts 561.1, 561.2 and 561.3 to specifically state that the accounts may be used by RTOs, other public utilities and licensees, consistent with the NOPR's language.

iii. Commission Conclusion

47. The proposed accounts for recording load dispatch, scheduling and system control expenses provide greater transparency concerning the types of costs incurred by both RTOs and non-RTO public utilities in providing transmission services. Therefore, we

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[41] APPA at 19.

[42] See SCE at 3.

will adopt the proposed accounting for load dispatch, scheduling and system control expenses. However, based upon the comments received, we will adopt the proposed accounting with certain clarifications and modifications as discussed below.

48. The instructions to Accounts 561.1, 561.2 and 561.3 are revised to make clear that the accounts are to be used by both RTOs and non-RTO public utilities. Additionally, the items list of Account 561.2 has been revised to include certain items included in replaced Account 561, Load Dispatching, which were inadvertently not included on the list. These modifications add clarity as to which entities are to use the accounts and what types of costs are to be recorded in the load dispatch, scheduling and system control expense accounts.

49. We will not adopt one commenter’s suggestion to realign the newly created accounts under its suggested new functions: system control and transmission service. The expanded expense accounts contained in the transmission function provide the requisite transparency concerning the activities and related costs incurred by public utilities, including RTOs, in providing transmission service for ratemaking and other Commission purposes. Moreover, the account structure appropriately herein adequately separates market service and transmission service activities.

50. Finally, we clarify that, to the extent that RTOs and non-RTO public utilities perform the same activities for load dispatch, scheduling and system control, then the costs of those activities should be accounted for in the same manner and recorded in the same accounts. For example, if an RTO incurs costs to manage the region-wide

reliability coordination function it would record those costs in Account 561.1. Likewise, if a non-RTO public utility happens to incur costs to manage the reliability coordination function for third parties, it would also record those costs in Account 561.1.

2. Accounts for System Planning and Standards Development

i. Accounting NOPR

51. In the NOPR, the Commission proposed to add a new Account 561.5, Long-Term Reliability Planning and Standards Development, to record the costs incurred by RTOs for performing long-term system planning and standards development.[43]

ii. Commenters

52. Some commenters request clarification of the Commission's proposed changes.[44] These commenters suggest that the definition provided in the NOPR does not provide a definitive basis to identify the costs to be recorded in this account because planning can be interpreted to have several meanings. National Grid requests that the Commission recognize that the scope of costs covered by Account 561.5 is likely to vary from region to region and clarity should be provided about the meaning of "long-term system planning." They explain that transmission planning occurs over several different time-scales such as short-term planning to intermediate planning to long term planning.[45] Indicated NYTOs request a waiver for transmission owners that are RTO members to

[43] NOPR at P 60-62.

[44] See, e.g., National Grid at 9-10.

[45] National Grid at 9-10.

allow consolidated reporting of *de minimus* amounts or alternatively guidance on the specific expenses to be recorded in the account.[46]

53. Other commenters support the proposed changes but believe the Commission should require additional accounts to offer more transparency and comparability. Specifically one commenter believes that Account 561.5 should be augmented by additional accounts for the portion of system planning, development and maintenance expenses that relate to market design initiatives and activities of RTOs, as opposed to control area operation.[47]

54. Finally, one commenter believes that the structure of this new account allows for inclusion of generation-related costs such as resource planning.

iii. <u>Commission Conclusion</u>

55. As the Commission explained in the NOPR, the existing USofA does not provide a specific expense account to record expenses for system planning and development activities. The Commission will adopt Account 561.5 as proposed as modified and discussed below. Commenters raise questions about the scope of planning costs that are to be recorded in Account 561.5 and how to record costs incurred relative to the different transmission planning time-scales, such as short-term, intermediate-term, and long-term. We will modify the instructions to Account 561.5 to allow inclusion of all transmission

[46] <u>See</u> Indicated NYTO at 9-10.

[47] <u>See</u> City of Santa Clara, California at 21-22.

system planning time-scale planning costs, not just long-term planning. We will therefore modify the title of the account to Account 561.5, Reliability, Planning and Standards Development, to reflect the fact that planning costs other than long-term are to be recorded in Account 561.5.

56. RTOs are directed to report costs of system planning, development, and maintenance expenses in Account 561.5. We clarify to the extent that public utilities and licensees that are not RTOs perform similar activities; they should also include the costs that they incur for system planning and standards development in Account 561.5. We also clarify that all system planning and standards development costs recorded in this account are to be transmission related.

57. The Commission declines at this time to augment Account 561.5 with additional accounts for the portion of system planning, development and maintenance expenses that relate to market design initiatives and activities of RTOs, as opposed to control area operation. We have created a new regional market expense function and all market planning and development costs shall be recorded in the appropriate market expense account based on the nature of the planning and development costs incurred.

3. Proposed Accounts for Study Costs

i. Accounting NOPR

58. The USofA does not specially provide accounts for recording costs incurred to perform generation interconnect and transmission service studies. Therefore, the Commission proposed to create Account 561.6, Transmission Service Studies, to record

the costs incurred by public utilities and licensees, including RTOs, to conduct studies for transmission service requests. The Commission also proposed to add a new Account 561.7, Generation Interconnection Studies, to record the costs incurred by public utilities and licensees, including RTOs to conduct studies for generator service requests.[48]

59. Additionally, in order to provide more disclosure concerning the costs of interconnect study activities being performed by public utilities and licensees, including RTOs, the Commission proposed to add a new schedule to the quarterly and annual financial reports that will provide more specifics concerning the costs of these activities.[49]

ii. Commenters

60. Commenters were of divergent views regarding the Commission's proposal to record costs to perform generation interconnect and transmission service studies in Account 561.6 and Account 561.7. Commenters state that it is not clear whether the proposed shift in accounting treatment of study costs could affect the billable or capital treatment of the underlying study costs. Commenters state that the costs of transmission service studies and generator interconnection studies are largely reimbursed by customers or folded into the capital accounting for transmission projects or upgrades, and would

[48] NOPR at P 63.

[49] Id. at P 64.

only be expensed in rare circumstances.[50] One commenter requests that the Commission clarify that the new expense accounts for study costs are not intended to cover all study costs, but only those costs that are neither reimbursed by customers nor capitalized. Alternatively, this commenter requests clarification that utilities may still charge out or capitalize such study costs as they have in the past.[51] Another commenter requests that the Commission exempt RTO member utilities from the proposed USofA changes for study costs because it provides little additional information. Alternatively, this commenter requests a waiver to eliminate reporting study costs in Account 561.6 and Account 561.7 because the costs are largely reimbursed by the RTO and will appear in the RTO financial reports. Additionally, this commenter requests that the cost of transmission service and generator interconnect studies be treated as capital expenditures.[52]

iii. Commission Conclusion

61. The Commission will adopt the proposed accounts for recording generation interconnection and transmission service study costs as clarified below. We clarify that Accounts 561.6 and 561.7 are only to be used to record the costs incurred by public utilities, including RTOs, to conduct studies for transmission service requests and

[50] National Grid at 10-12, Indicated NYTOs at 6 -10.

[51] National Grid at 10-12.

[52] Indicated NYTOs at 6 -10

generator service requests, respectively, when the costs are not directly reimbursable by a specific customer and the costs are otherwise charged to expense under the USofA..

62. Additionally, we clarify that the Commission did not propose any change and does not do so now related to the recording of the costs of conducting transmission and generation interconnect studies in Account 186, Miscellaneous Debits, by public utilities, including RTOs, pending reimbursement by the entity requiring the service. We further clarify that the Commission did not intend to change any capitalization requirements related to study costs. Public utilities are to continue to follow the Commission's existing rules and regulations for cost capitalization.

4. Accounts for RTO Billings

i. Accounting NOPR

63. In the NOPR, the Commission proposed to create three new sub-accounts in order to provide greater transparency for the payments made by public utilities and licensees to RTOs. The three new proposed sub-accounts are Account 561.4, Scheduling, System Control and Dispatching Services; Account 561.8, Reliability Planning and Standards Development Services; Account 575.7, Market Facilitation, Monitoring and Compliance Services.[53] The proposed new sub-accounts will be used by public utilities and licensees to record their share of costs billed to them by an RTO. Additionally, the Commission

[53] NOPR at P 65-68.

proposed that each RTO include in its monthly settlement statements a breakdown of the allocation of that RTO's operational costs within each of the three sub-accounts discussed below

ii. Commenters

64. Commenters generally agree that non-RTO public utilities should record in separate sub-accounts the charges paid to RTOs and suggest that the Commission add more sub-accounts to separately disclose additional costs incurred by non-RTO public utilities.[54]

65. One commenter seeks clarification of the Commission's intent with respect to proposed Account 575.7 Market Facilitation, Monitoring and Compliance Services.[55] This commenter questions if the Commission intends that only costs billed to utilities by the RTOs be included in this account, not including costs by utilities performing functions that meet the description of the account. The commenter explains that decisions made regarding rate recovery of Balancing Authority costs by transmission owners are likely to depend heavily on how relevant costs are recorded and requests that the Commission clarify that Account 575.7 is only applicable to costs billed to utilities by RTOs.

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[54] See City of Santa Clara, California at 25-26, EEI at 7-8.

[55] First Energy at 17.

66. Finally, one commenter requests that the Commission not adopt an absolute rule that information on the three new cost sub-accounts be part of the settlement statements.[56] This commenter believes it will be expensive to include such cost breakdowns in monthly customer settlement statements. This commenter states that RTOs have sophisticated billing software that is not easy to modify and that a number of RTOs would have to make expensive and time-consuming changes to their billing systems in order to incorporate the required cost information directly into monthly settlement statements. This commenter suggests that a more flexible approach would recognize the reality that different RTOs have different software capabilities and allow each entity to comply with the Commission's requirement in their own efficient way.

iii. Commission Conclusion

67. The Commission will adopt the new accounts for RTO billings proposed in the NOPR with the modification discussed below. As the Commission explained in the NOPR, these new accounts will allow each RTO member to record its share of the RTO's total monthly operating costs in these new sub-accounts. The Commission will also require each RTO provide a breakdown of the allocation of that RTO's operational costs within each of the three sub-accounts. However, the Commission will not require RTOs to include this information in its monthly settlement statements because of software costs to implement changes to the RTO billing systems. Instead, the Commission will permit

[56] See ISO/RTO Council at 3-4.

RTOs to use another format to provide the information to its members. However, RTOs are nevertheless directed to provide a breakdown of the cost allocation to the three new sub-accounts on the date the billings are issued.

68. The Commission also clarifies that Account 575.7 is to be used only for costs billed to utilities by RTOs for market administration, monitoring and compliance services.

5. Account for Revenue From Transmission of Electricity

i. Accounting NOPR

69. In the NOPR, the Commission proposed to add a new sub-account to Account 456, Other Electric Revenues, in order to provide greater transparency by transmission owners for the revenues received for use of their transmission facilities.[57]

ii. Commenters

70. Commenters were generally supportive, but request that the Commission provide additional clarification.[58] One commenter requests that the Commission provide even more transparency regarding the particular sources of those revenues and how they relate to common ratemaking categories. This commenter suggests the Commission implement accounting for transmission revenues that would enable customers and the Commission to monitor whether previously accepted rates generate more than an appropriate level of

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[57] NOPR at P 73-74.

[58] TAPS at 6-8, International Transmission at 7.

revenues. This commenter requests that the Commission remedy its accounting and reporting, in this proceeding, to keep pace with standard ratemaking practice so that Form 1 information provides accounting data for direct ratemaking use.[59] Another commenter requests the Commission clarify that non-RTO public utilities should use the new Account 456.1 for transmission service revenues and existing Account 456 for miscellaneous revenues.

iii. Commission Conclusion

71. The Commission will adopt the new sub-account as proposed in the NOPR. The new Account 456.1, Revenues From Transmission of Electricity of Others, will include revenues the transmission owner receives for the transmission of electricity over its transmission facilities. This new account will provide greater transparency with respect to the revenues received by transmission owners for use of their transmission facilities. We also clarify that revised Account 456 is to be used for recording non-transmission miscellaneous operating revenues.

6. Accounting for Settlement Amounts

i. Accounting NOPR

72. In the NOPR, the Commission proposed that public utilities or licensees that conduct energy transactions through an RTO that requires participants to bid their generation into the market and buy generation to supply their native load report these

[59] TAPS at 6-8

transactions on a net basis in Account 555, Purchased Power.[60] The Commission also invited comment as to what circumstances would be appropriate for a public utility or licensee to reflect these types of transactions on a net basis, and under what circumstances would it be appropriate for a public utility or licensee to reflect these types of transactions as distinct purchases and sales.

ii. <u>Commenters</u>

73. Two commenters do not support the netting of transactions that flow through RTO energy markets.[61] One of these commenters argues that for accounting and tax purposes, purchased power should, on financial statements, represent only purchased power. This commenter also asserts that its members that are subject to Rural Utilities Service (RUS) oversight need to be able to report gross amounts of energy sales to RUS. This commenter further asserts that it will be difficult for cooperatives to determine income for income tax purposes if only net transactions are reported.[62] The other commenter argues that showing only the net position of a market participant may understate the use of RTO energy markets and mask situations where a utility is a net seller during one period but a net buyer in another period. This commenter also notes that netting would

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[60] NOPR at P 75-79.

[61] <u>See</u> APPA at 2, NRECA at 4.

[62] NRECA at 5.

not reveal the effects of time and location-specific variation in energy prices, yielding only incomplete results that are unlikely to be meaningful.[63]

74. Most other commenters, however, generally agree that these transactions should be reported on a net basis.[64] One commenter submits that reporting these types of transactions on a gross basis might give an inaccurate picture of an entity's size and its actual revenue-generating activities.[65] This commenter suggests that accounting for transactions settled through RTO markets on a net basis more accurately reflects what similarly situated utilities would be doing in the absence of RTO markets. This commenter also suggests that accounting on a gross basis would cause it to incur an artificially large gross receipts tax liability which would act as a deterrent to participation in RTO markets. This commenter further suggests that accounting for these transactions on a net basis is in accord with traditional accounting principles regarding whether to record transactions on a gross or net basis.

75. Some commenters support netting, but believe that it is inappropriate to report net sales in Account 555.[66] These commenters assert that net sellers of generation should report the transactions in Account 447, Sales for Resale, and that net purchasers should

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[63] APPA at 2.

[64] See First Energy at 15, MGE at 2, Wisconsin Electric at 3, EEI at 6, APS at 3, Cinergy at 4, NYTOs at 12, SCE at 1.

[65] See MGE at 3.

[66] EEI at 6, First Energy at 16, Wisconsin Electric at 4.

report the transactions in Account 555, Purchase Power. One commenter notes that consistent with the reporting methodology of its RTO it reports sales and purchases of power on an hourly net position basis. For each hour that the company is a net seller of power, the commenter states that it reports the net amount in Account 447; conversely, if it is net buyer of power, it reports the net amount in Account 555. In each monthly reporting period, the commenter notes that the hourly Account 447 and/or Account 555 net amounts are aggregated and separately reported in Account 447and 555, respectively.

76. Some commenters also recommend that the Commission allow companies flexibility in determining net sales and/or purchases during the relevant reporting period and for using the appropriate account or accounts to display its net sales and/or purchases.[67] One of these commenters suggests that some companies may choose to net their purchases and sales for the entire reporting period, while others may reflect separately net purchases when the company was a net buyer and net sales when it was a net seller.

77. On the other hand, one commenter suggests that the Commission define a uniform method for the calculation of the gross amount of sales versus purchases, whether it be by the hour, day, week or month.[68] This commenter argues that, without such a standard, a wide range of interpretation and reporting is likely to result.

[67] EEI at 7, First Energy at 16.

[68] NRECA at 3.

78. Another commenter asserts that netting should be allowed for transactions in all RTO markets.[69] This commenter suggests that the Commission clarify that netting of purchases from and sales into an RTO market is appropriate and allowed not only for transactions in an RTO that requires participants to offer all resources to and buy all power from the RTO, but for transactions in any RTO that offers an energy market in which participants may choose to offer all generation to and buy all power from the energy market. This commenter also suggests that the Commission clarify that purchases from and sales to one or more RTO markets may be netted against one another.

79. Finally, one commenter recommends that the Commission's Electronic Quarterly Reports (EQR) and annual reports be revised to match the accounting methodology using the Commission's USofA with the required reporting format.[70] While another commenter notes that there is a disconnect between the reporting of transactional data in the EQRs and reporting of the data in the FERC Form 1, stemming from how the data are defined in those two contexts. This commenter recommends that when the Commission next entertains revisions to one or the other of the forms, the Commission should discuss this issue with reporting entities to determine if some clarification aimed at conformity would be appropriate.[71]

[69] MGE at 3.

[70] Wisconsin Electric at 4.

[71] EEI at 7.

iii. Commission Conclusion

80. Recording RTO energy market transactions on a net basis is appropriate as purchase and sale transactions taking place in the same reporting period to serve native load are done in contemplation of each other and should be combined. Netting accurately reflects what participants would be recording on their books and records in the absence of the use of an RTO market to serve their native load. Recording these transactions on a gross basis, in contrast, would give an inaccurate picture of a participant's size and revenue producing potential. The Commission will, therefore, adopt the proposed accounting for RTO energy market transactions with certain modifications and clarifications as discussed below. The Commission does expect public utilities, however, to maintain detailed records for auditing purposes of the gross sale and purchase transactions that support the net energy market amounts recorded on their books.

81. Additionally, we clarify that transactions are to be netted based on the RTO market reporting period in which the transaction takes place. For example, if the RTO market in which the transaction takes place uses an hourly period for determining energy market charges and credits, then non-RTO public utilities purchasing and selling energy in the market must net transactions on an hourly basis. Requiring participants to net transactions over the RTO market's reporting period leads to consistent and comparable energy market information for decision making purposes by the Commission and others.

82. Further, we clarify that the netting of purchases and sales in an RTO energy market is appropriate not only for transactions where participants are required to bid their

generation into the market and buy generation from the market to supply their native load, but also in cases where an RTO offers an energy market in which participants may choose to offer all generation to and buy all power from the energy market.

83. We also clarify that if a participant is a net seller, rather than a net buyer, during a given market reporting period it must credit such net sales to Account 447, Sales for Resale, instead of Account 555, Purchased Power.

84. Finally, one purpose of this rule is to establish uniform accounting requirements for the purchase and sale of energy in RTO markets. The purpose of reporting of gross information in EQRs, in contrast, is to provide the Commission and the public with a more complete picture of wholesale market activities which affect jurisdictional services and rates, thereby helping to monitor for any market power and to ensure that customers are protected from improper conduct. These are not necessarily the same criteria and principles that should be used in establishing uniform accounting requirements. In any event, the reporting of wholesale market activity in EQRs falls outside the scope of this rule.

7. <u>Ministerial Filings</u>

85. Some commenters argue that certain revisions to the USofA will adversely affect the Attachment O formula rate which is used by the vast majority of the transmission owners in the Midwest ISO and other formula rates that rely on the USofA and Form 1

data for the rate inputs.[72] Specifically, for the Midwest ISO, new accounts or renumbered accounts may cause disruptions in the operation of the Attachment O formula rate, especially if there is no parallel revision to Attachment O to reflect these changes. Some commenters therefore request that the Commission clarify that it will accept "ministerial" filings in order to conform these formula rates to the final revisions of the USofA.[73]

86. In particular, FirstEnergy, among others, has expressed concern that the Commission ensure that the revisions to its accounting and financial reporting requirements will not provide an opportunity for challenges to Commission-approved formula rates nor shall the Commission entertain such challenges to these previously-accepted rates.[74] Therefore, the Commission should state that it will accept "ministerial" filings necessary to conform to the Final Rule all Commission accepted formula rates that rely on Form 1 inputs. FirstEnergy further argues that the Commission should provide a specific timeline to allow such filings but coordinate the respective effective dates of the rate filings and reporting changes to ensure that there is no gap in cost recovery.[75] International Transmission requests that the Final Rule establish a compliance filing

[72] See FirstEnergy at 13, International Transmission at 4, EEI at 10.

[73] See FirstEnergy at 1-2, 13-15, International Transmission at 3-4.

[74] International Transmission at 3-4, FirstEnergy at 14.

[75] FirstEnergy at 14.

process, rather than allow a Federal Power Act section 205 filing,[76] so that there will be no challenges to ministerial filings in order for public utilities to revise the formula rate templates.[77]

Commission Conclusion

87. We will allow revisions to tariffs to conform to the changes adopted here, but pursuant to section 205. We will, however, consider only comments that address the specific revisions necessary to comply with these accounting and reporting revisions. By narrowly focusing the scope of the filings and of the comments to only those changes necessary to conform to this Final Rule, public utilities can be assured that commenters cannot otherwise and inappropriately challenge the reasonableness of their Commission-approved and accepted formula rates.

88. We also find that any necessary revisions to formula rates in order to conform to the Final Rule should not increase rates. The requisite changes to Attachment O, for example, would be the result of the new accounts and would solely reflect accounting changes adopted in this Final Rule. Such changes also should not involve substantive changes to the way the formula rates operate or the way the charges are calculated.

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[76] 16 U.S.C. 824d (2000).

[77] International Transmission at 4.

8. Cost Oversight

89. The Commission received multiple comments regarding cost oversight in response to the accounting and financial reporting NOPR. Commenters assert that the restructuring of the electric industry will only benefit consumers if transmission organizations are subject to greater efficiency and accountability.[78] As the National Rural Electric Cooperative Association (NRECA) states, "[t]he absence of common standards and rules currently hampers meaningful examination of the cost-effectiveness of the products and services that RTOs/ISOs offer."[79]

90. Commenters have also included general suggestions to the Commission, which they argue, would not only enhance and facilitate transparency and comparability of RTO finances, but could also be an integral first step towards controlling RTO operational costs. Among other things, commenters have suggested that the Commission require RTOs to include a detailed analysis of their business risks and opportunities as part of their periodic financial reporting.[80]

91. A few commenters also urge the Commission to continue its efforts in reviewing the cost oversight and accountability in the budgeting and expenditure process that RTOs

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[78] See, e.g., ELCON at 1, IESO at 2.

[79] See NRECA at 2.

[80] Indicated NYTOs at 2, 5-6.

utilize.[81] Revision of the USofA represents only a partial solution in providing adequate transparency and accountability in RTO financial reporting.

92. Commenters have expressed concern that the Commission's proposed revisions fall short in meeting the goal of ensuring that the costs of the RTOs are legitimate and reasonable.[82] Cinergy has therefore, for example, proposed that RTOs annually file with the Commission a formula cost assignment template which supports the projected RTO costs by billing schedule for a twelve month period. This report, Cinergy explains, would include detailed projected direct costs and a proposed assignment/allocation of overhead costs to the specific schedule. This would provide parties with an opportunity to comment and prior Commission approval would be required before the RTO could proceed with the expenditure.

93. Midwest ISO Transmission Owners argue that the proposed revisions to the USofA lack before-the-fact review of costs. They contend that while after-the-fact review of costs is being done if an RTO has a formula rate, it does not adequately respond to the needs of these not-for-profit entities, as an entity's "not-for-profit status complicates a prudence review after the costs are incurred."[83] Midwest ISO Transmission Owners therefore suggest that, in order to keep the Commission and RTO

[81] See, e.g., NEPOOL Participants Committee at 1-5.

[82] See, e.g., Cinergy and Midwest ISO Transmission Owners.

[83] Midwest ISO Transmission Owners at 5, citing Midwest Independent Transmission System Operators, Inc., 101 FERC ¶ 61,221 (2002).

members, as well as interested state commission, abreast of estimated and actual expenditures and to provide RTO members due process, the Commission should require approval before the RTO incurs significant costs and also require regular reporting after costs have been incurred.

Commission Conclusion

94. We recognize that there are divergent views as to the best way to accomplish the goals of this initiative. The accounting and form changes adopted herein add visibility and uniformity to the accounting and financial reporting for the costs of transmission and market operation plant, and the expenses incurred and revenue received in providing transmission and market services. The changes provide comparability among RTOs and non-RTO public utilities that perform region-wide transmission and market operations, and minimize inconsistent reporting by RTOs and non-RTO public utilities. Further, these revisions allow the Commission to better understand transactions and events that affect RTOs and their members and non-RTO public utilities.

95. The Commission expects the changes in financial reporting to lead to improvements in cost recovery practices by providing more details concerning the costs of certain functions and increased assurance that the costs are legitimate and reasonable costs of providing service and assigned to the correct period for recovery in rates. We believe the changes we are adopting herein are an important first step. The concerns raised with regard to RTO cost oversight, including the budgeting process, the expenditure process, and the analysis of RTO business risks and opportunities are beyond

the scope of this proceeding. However, cost oversight practices are an important aspect of the initiative we began with the NOI and we intend to address those matters in the near future.

9. Other Matters

96. The Commission noted in the NOPR that the derivative and asset retirement accounts established under Order Nos. 627 and 631 were not included in the Chart of Account listings contained in the USofA.[84] The Commission here takes this opportunity to update the account listing to include the accounts established under these orders.

IV. Effective Date

i. Accounting NOPR

97. In the NOPR, the Commission proposed that the aforementioned accounting and financial reporting changes and updates would become effective on January 1, 2006.[85]

ii. Commenters

98. Most of the commenters suggest the Commission instead adopt a January 1, 2007 effective date. Some of the commenters believe non-RTO public utilities face a substantial burden of implementation because of other obligations and functions performed by these companies.[86] One commenter explains that it has Sarbanes-Oxley

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[84] NOPR at P 80.

[85] Id. at P 82.

[86] See EEI at 11-12, SoCal ED at 4, First Energy at 11-13.

Act concerns about any proposal that would require changes, reconfigurations or modifications to its general ledger computer systems and reporting structures, and/or the methodology of the reporting of RTO-related revenue and cost transactions. This commenter requests that the Commission provide sufficient time to implement, internally test and have any necessarily validations by external auditors of such changes or modifications.[87] Another commenter expresses similar concerns and requests that the Commission provide a minimum of three months to adjust their accounting and reporting systems. This commenter explains that the easiest time for companies to implement changes in the start of a fiscal year, typically the calendar year.[88] Other commenters indicate that more time is needed to allow for more coordination, discussion and consideration of the complexities of all the issues.[89] Another commenter submits that the rule take effect on the proposed date unless it places an undue burden on the industry as a whole or on some public utilities; in which case, the commenter recommends that RTOs submit pro forma financial statements conforming to the new rules on the proposed date.[90]

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[87] First Energy at 11-13.

[88] EEI at 11.

[89] See National Grid at 13-14, Indicated NYTOs at 11-12.

[90] See APPA at 7-8.

99. Commenters generally were in agreement that the Commission should not require comparative analyses of the new data for earlier reporting periods. Commenters contend that it would be unduly burdensome for FERC Form 1 and 3-Q filers to go back in time to try to capture retroactive prior period information for the new sub-accounts.[91]

iii. Commission Conclusion

100. The accounting and form changes adopted herein add visibility and uniformity to the accounting and financial reporting for the costs of transmission and market operation plant, and the expenses incurred and revenue received in providing transmission and market services. The changes provide comparability among RTOs and non-RTO public utilities that perform region wide transmission and market operations, and minimize inconsistent reporting by RTOs and non-RTO public utilities. Further, these revisions allow the Commission to better understand transactions and events that affect RTOs and their members and non-RTO public utilities.

101. The Commission also expects the changes in financial reporting to lead to improvements in cost recovery practices by providing more details concerning the costs of certain functions and increased assurance that the costs are legitimate and reasonable costs of providing service and assigned to the correct period for recovery in rates.

102. For the above reasons, the Commission orders that the aforementioned accounting and financial reporting changes and updates become effective on January 1, 2006. The

[91] See EEI at 12.

Commission believes it is imperative to obtain as quickly as possible adequate transparency of transactions and business functions among and between RTOs and their member public utilities as well as non-RTO public utilities to allow for prudent choices to be made on issues such as optimizing the efficiency of business functions. Hence, the Commission adopts a January 1, 2006 effective date as originally proposed in the NOPR.

103. The Commission clarifies that it has no intention of requiring public utilities to report prior period information in the newly-created accounts for FERC Form 1 and 3-Q purposes. Public utilities should report prior period information in the accounts originally used, except for Account 561, Load Dispatching. Since Account 561 is being replaced by newly-created sub-accounts, public utilities should report amounts reported in Account 561 for 2005 in Account 561.2[92] for the 2006 Form 1 filed in April 2007 and for the Form 3-Qs filed in 2006. This approach will alleviate any burden associated with reporting prior period information.

V. Changes To The FERC Quarterly And Annual Report Forms

104. The changes adopted herein will require revising the existing schedules in the FERC Forms 1, 1-F and 3-Q filed with the Commission. Appendix B contains samples

[92] This is for reporting purposes only and no amounts should be reclassified for accounting purposes.

of the updated or new schedules that will be included in these reports and will be available on e-Library.[93]

VI. Information Collection Statement

105. The following collections of information referenced in this Final Rule have been submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995.[94] OMB's regulations require OMB to approve certain information collection requirements imposed by agency rule.[95] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this Final Rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number or the Commission had provided a justification as why the control number should be displayed.

[93] Appendix B will not be published in the Federal Register.

[94] See 44 U.S.C. 3507(d) (2000).

[95] 5 CFR 1320.11.

106. The following burden estimates are for complying with this final rule as follows:

	Data Collection	Number of Respondents	Number of Responses	Hours Per Response	Total
1	Form 1 (RTOs)	6	1	35	210
2	Form 1 (Non-RTOs)	214	1	11	2,354
3	Form 1-F	33	1	11	363
4	Form 3-Q (RTOs)	6	3	30	540
5	Form 3-Q (Non-RTOs)	247	3	15	11,115
	Totals				14,582

<u>Information Collection Costs</u>*:* The Commission has projected the average annualized cost of all respondents to be the following: 14,582 hrs. + (2 hrs recordkeeping x 253 respondents) = 15,088 hrs. @ $60 per hour = $905,280 for respondents. No capital startup costs are estimated to be incurred by respondents.

Annualized Costs (Operations & Maintenance): The costs for performing the prepared schedules are rolled into the total costs for completing the Commission's annual and quarterly financial reports.

<u>Title</u>*:* FERC Form 1, "Annual report of Major electric utilities, licensees, and others"

FERC Form 1-F, "Annual report for Nonmajor public utilities and licensees"

FERC Form 3-Q, "Quarterly financial report of electric utilities, licensees, and natural gas companies"

Action: Information collections.

OMB Control Nos.: 1902-0021; 1902-0029; and 1902-0205.

Respondents: Businesses or other for profit.

Frequency of responses: Annually and quarterly.

Necessity of the Information: This Final Rule revises the Commission's regulations to reflect changes that are occurring in the electric industry due to the availability of open-access transmission service and increasing competition in the wholesale bulk power industry. The addition of these new accounts is intended to standardize accounting for transactions and events affecting public utilities and licensees, including independent system operators and regional transmission organizations that file financial reports with the Commission. The accounting regulations currently found in the USofA and related financial reporting requirements capture financial information along traditional primary business functions but do not provide sufficient detailed information concerning RTOs and, in particular, the costs incurred by these organizations as well as non-RTO public utilities that engage in similar activities. The addition of these accounts, and related changes in reporting, are intended to improve the transparency, completeness and consistency of accounting practices for the cost of assets, the expenses incurred in providing services, along with revenues collected. Without specific instructions and accounts for recording and reporting the above transactions and events, inconsistent and incomplete accounting and reporting will result.

Internal Review: The Commission has reviewed the requirements pertaining to the USofA and to the financial reports it prescribes and determined that the proposed revisions are necessary because the Commission needs to establish uniform accounting and reporting requirements for the costs of utility assets and the expenses incurred for providing services as part of utility operations.

107. These requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

108. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, D.C. 20426 [Attention: Michael Miller, Office of the Executive Director, Phone (202)502-8415, fax: (202)273-0873, e-mail: michael.miller@ferc.gov]

109. For submitting comments concerning the collection of information(s) and the associated burden estimates, please send your comments to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, D.C. 20503, Attention: Desk Officer for the Federal Energy Regulatory Commission; Phone: (202)395-4650, fax: (202)395-7285.

VII. Environmental Analysis

110. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect

on the human environment.[96] No environmental consideration is necessary for the promulgation of a rule that addresses information gathering, analysis, and dissemination,[97] and also that addresses accounting.[98] This Final Rule addresses accounting. In addition, this Final Rule involves information gathering, analysis, and dissemination. Therefore, the Final Rule falls within categorical exemptions provided in the Commission's regulations. Consequently, neither an environmental impact statement nor an environmental assessment is required.

VIII. Regulatory Flexibility Act

111. The Regulatory Flexibility Act of 1980 (RFA)[99] generally requires a description and analysis of the effect that the final rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities.

112. The Commission concludes that this rule would not have such an impact on a substantial number of small entities. Most companies regulated by the Commission do

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[96] See Regulations Implementing the National Environmental Policy Act, Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[97] See 18 CFR 380.4(a)(5).

[98] See 18 CFR 380.4(c)(16).

[99] See 5 U.S.C. 601-612 (2000).

not fall within the RFA's definition of a small entity;[100] this rule applies principally to public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce and not electric utilities per se. The Commission also concludes that this rule will not impose a significant burden on industry since the information is already being captured by their accounting systems and generally being reported at a consolidated business level.

IX. Document Availabilty

113. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

114. From the Commission's Home Page on the Internet, this information is available in the Commission's management system, e-Library. The full text of this document is

[100] See 5 U.S.C. 601(3) citing to section 3 of the Small Business Act, 15 U.S.C. 632. Section 3 of the Small Business Act defines a "small-business concern" as a business which is independently owned and operated and which is not dominant in its field of operation. The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal years did not exceed 4 million MWh. 13 CFR 121.201.

available on e-Library in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in e-Library, type the docket number excluding the last three digits of this document in the docket number field.

115. User assistance is available for e-Library and the Commission's website during normal business hours from our Help line at (202) 502-8222 or the Public Reference Room at (202) 502-8371, Press 0, TTY (202) 502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov

Effective Date and Congressional Notification

This Final Rule will take effect January 1, 2006. The Commission has determined with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is not a major rule within the meaning of section 251 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit the Final Rule to both houses of Congress and the General Accounting Office.

List of subjects in 18 C.F.R. Part 101

Electric power, electric utilities, Reporting and recordkeeping requirements, and Uniform System of Accounts.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

In consideration of the foregoing, the Commission amends Part 101, Chapter I, Title 18, Code of Federal Regulations, as follows.

PART 101 - UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

1. The authority citation for Part 101 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352, 7651-7651o.

2. In part 101, Definitions, redesignate definitions 30-39 as definitions 31-40 and add new definition 30. Regional market to the list to read as follows:

* * * * *

30. Regional market means an organized energy market operated by a public utility, whether directly or through a contractual relationship with another entity.

3. In part 101, Balance Sheet Chart of Accounts, Accounts 175, 176, 219, 230, 244, and 245 are added to the list:

Balance Sheet Chart of Accounts

ASSETS AND OTHER DEBITS

* * * * *

3. CURRENT AND ACCRUED ASSETS

*   *   *   *   *

175 Derivative instrument assets.

176 Derivative instrument assets-Hedges.

*   *   *   *   *

LIABILITIES AND OTHER CREDITS

5. PROPRIETARY CAPITAL

*   *   *   *   *

219 Accumulated other comprehensive income.

*   *   *   *   *

7. OTHER NONCURRENT LIABILITIES

*   *   *   *   *

230 Asset retirement obligations.

8. CURRENT AND ACCRUED LIABILITIES

*   *   *   *   *

244 Derivatives instrument liabilities.

245 Derivative instrument liabilities-Hedges.

*   *   *   *   *

4. In part 101, Balance Sheet Accounts, Account 108, paragraph C is revised to read as follows:

* * * * *

108 Accumulated provision for depreciation of electric utility plant (Major only).

* * * * *

C. For general ledger and balance sheet purposes, this account shall be regarded and treated as a single composite provision for depreciation. For purposes of analysis, however, each utility shall maintain subsidiary records in which this account is segregated according to the following functional classification for electric plant:

(1) Steam production,

(2) Nuclear production,

(3) Hydraulic production,

(4) Other production,

(5) Transmission,

(6) Distribution,

(7) Regional Transmission and Market Operation, and

(8) General.

These subsidiary records shall reflect the current credits and debits to this account in sufficient detail to show separately for each such functional classification:

(a) the amount of accrual for depreciation,

(b) the book cost of property retired,

(c) cost of removal,

(d) salvage, and

(e) other items, including recoveries from insurance.

Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in Account 108, Accumulated provision for depreciation of electric utility plant (Major only).

* * * * *

5. In part 101, Electric Plant Chart of Accounts, Accounts 317, 326, 337, 347, 359.1, and 374 are added to the list:

Electric Plant Chart of Accounts

* * * * *

2. PRODUCTION PLANT

A. STEAM PRODUCTION

* * * * *

317 Asset retirement costs for steam production plant.

B. NUCLEAR PRODUCTION

* * * * *

326 Asset retirement costs for nuclear production plant (Major only).

* * * * *

C. HYDRAULIC PRODUCTION

* * * * *

337 Asset retirement costs for hydraulic production plant.

D. OTHER PRODUCTION

* * * * *

347 Asset retirement costs for other production plant.

3. TRANSMISSION PLANT

* * * * *

359.1 Asset retirement costs for transmission plant.

4. DISTRIBUTION PLANT

* * * * *

374 Asset retirement costs for distribution plant.

6. In part 101, Electric Plant Chart of Accounts, a new section with primary plant account listing is added as follows:

5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT

380 Land and land rights.

381 Structures and improvements.

382 Computer hardware.

383 Computer software.

384 Communication Equipment.

385 Miscellaneous Regional Transmission and Market Operation Plant.

386 Asset Retirement Costs for Regional Transmission and Market Operation Plant.

387 [Reserved]

7. In Part 101, Electric Plant Accounts, new primary plant accounts 380, 381, 382, 383, 384, 385, and 386 are added to read as follows:

Electric Plant Accounts

* * * * *

380 Land and land rights.

This account shall include the cost of land and land rights used in connection with regional transmission and market operations.

381 Structures and improvements.

This account shall include the cost in place of structures and improvements used for regional transmission and market operations.

382 Computer hardware.

This account shall include the cost of computer hardware and miscellaneous information technology equipment to provide scheduling, system control and dispatching, system planning, standards development, market monitoring, and market administration activities. Records shall be maintained identifying to the maximum extent practicable computer hardware owned and used for: (1) scheduling, system control and dispatching,

(2) system planning and standards development, and (3) market monitoring and market administration activities.

ITEMS

1. Personal computers
2. Servers
3. Workstations
4. Energy Management System (EMS) hardware
5. Supervisory Control and Data Acquisition (SCADA) system hardware
6. Peripheral equipment
7. Networking components

383 Computer software.

This account shall include the cost of off-the-shelf and in-house developed software purchased and used to provide scheduling, system control and dispatching, system planning, standards development, market monitoring, and market administration activities. Records shall be maintained identifying to the maximum extent practicable the cost of software used for:

(1) scheduling, system control and dispatching,

(2) system planning and standards development, and

(3) market monitoring and market administration activities.

ITEMS

1. Software licenses

2. User interface software

3. Modeling software

4. Database software

5. Tracking and monitoring software

6. Energy Management System (EMS) software

7. Supervisory Control and Data Acquisition (SCADA) system software

8. Evaluation and assessment system software

9. Operating, planning and transaction scheduling software

10. Reliability applications

11. Market application software

384 Communication equipment.

This account shall include the cost of communication equipment owned and used to acquire or share data and information used to control and dispatch the system.

ITEMS

1. Fiber optic cable

2. Remote terminal units

3. Microwave towers

4. Global Positioning System (GPS) equipment

5. Servers

6. Workstations

7. Telephones

385 Miscellaneous regional transmission and market operation plant.

This account shall include the cost of regional transmission and market operation plant and equipment not provided for elsewhere,

386 Asset retirement costs for regional transmission and market operation plant.

This account shall include asset retirement costs on regional control and market operation plant and equipment.

8. In part 101, Electric Plant Chart of Accounts, 5. General Plant, is redesignated as 6. General Plant, and a new Account 399.1 is added to the list.

399.1 Asset retirement costs for general plant.

9. In part 101, Operating Revenue Chart of Accounts, new Accounts 456.1, 457.1 and 457.2 are added to the other operating revenue listing as follows:

Operating Revenue Chart of Accounts

*   *   *   *   *

2. OTHER OPERATING REVENUES

456.1 Revenues from transmission of electricity of others.

457.1 Regional transmission service revenues.

457.2 Miscellaneous revenues.

10. In part 101, Income Accounts, Account 456 Item 5 is removed, and Item 6 is redesignated as Item 5.

11. In part 101, Income Accounts, new revenue accounts 456.1, 457.1, and 457.2 are added to read as follows:

Operating Revenue Accounts

*   *   *   *   *

456.1 Revenues from transmission of electricity of others.

This account shall include revenues from transmission of electricity of others over transmission facilities of the utility.

457.1 Regional transmission service revenues.

This account shall include revenues derived from providing scheduling, system control and dispatching services. Include also in this account reimbursements for system planning, standards development, and market monitoring and market compliance activities. Records shall be maintained so as to show: (1) the services supplied and revenues received from each customer and (2) the amounts billed by tariff or specified rates.

457.2 Miscellaneous revenues.

This account shall include revenues and reimbursements for costs incurred by regional transmission service providers not provided for elsewhere. Records shall be maintained so as to show: (1) the services supplied and revenues received from each customer, and (2) the amounts billed by tariff or specified rates.

12. In part 101, Operation and Maintenance Expense Chart of Accounts, a new Regional Market Expenses function is added and new Accounts 575.1 575.2, 575.3, 575.4, 575.5, 575.6, 575.7, 575.8, 576.1, 576.2, 576.3, 576.4 and 576.5 are added as follows:

Operation and Maintenance Expense Chart of Accounts

* * * * *

3. REGIONAL MARKET EXPENSES

Operation

575.1 Operation Supervision

575.2 Day-ahead and real-time market facilitation.

575.3 Transmission rights market facilitation.

575.4 Capacity market facilitation.

575.5 Ancillary services market facilitation

575.6 Market monitoring and compliance

575.7 Market facilitation, monitoring and compliance services

575.8 Rents

Maintenance

576.1 Maintenance of structures and improvements

576.2 Maintenance of computer hardware

567.3 Maintenance of computer software

567.4 Maintenance of communication equipment

567.5 Maintenance of miscellaneous market operation plant

13. In part 101, Operation and Maintenance Expense Chart of Accounts, 3. Distribution Expenses is redesignated as 4. Distribution Expenses; 4. Customer Accounts Expenses is redesignated as 5. Customer Accounts Expenses; 5. Customer Service and Informational Expenses is redesignated as 6. Customer Service and Informational Expenses; 6. Sales Expense is redesignated as 7. Sales Expenses; and 7. Administrative and General Expenses is redesignated as 8. Administrative and General Expenses.

14. In part 101, Operation and Maintenance Expense Chart of Accounts, the listing of transmission expenses is removed and replaced with the following list of accounts:

Operation and Maintenance Expense Chart of Accounts

* * * * *

2. TRANSMISSION EXPENSES

Operation

560 Operation supervision and engineering

561.1 Load dispatch-Reliability

561.2 Load dispatch-Monitor and operate transmission system.

561.3 Load dispatch-Transmission service and scheduling.

561.4 Scheduling, system control and dispatch services.

561.5 Reliability planning and standards development.

561.6 Transmission service studies.

561.7 Generation interconnection studies.

561.8 Reliability planning and standards development services

562 Station expenses (Major only).

563 Overhead line expenses (Major only).

564 Underground line expenses (Major only).

565 Transmission of electricity by others (Major only).

566 Miscellaneous transmission expenses (Major only).

567 Rents.

567.1 Operation supplies and expenses (Nonmajor only).

Maintenance

568 Maintenance supervision and engineering (Major only).

569 Maintenance of structures (Major only).

569.1 Maintenance of computer hardware.

569.2 Maintenance of computer software.

569.3 Maintenance of communication equipment.

569.4 Maintenance of miscellaneous regional transmission plant.

570 Maintenance of station equipment (Major only).

571 Maintenance of overhead lines (Major only).

572 Maintenance of underground lines (Major only).

573 Maintenance of miscellaneous transmission plant (Major only).

574 Maintenance of transmission plant (Nonmajor only).

15. In part 101, Operation and Maintenance Expense Accounts, the first paragraph of Account 556 instruction is revised to read as follows:

Operation and Maintenance Expense Accounts

*** * * * ***

Account 556 System control and load dispatching (Major only).

This account shall include the cost of labor and expenses incurred in load dispatching activities for system control. Utilities having an interconnected electric system or operating under a central authority which controls the production and dispatching of electricity may apportion these costs to this account and transmission expense Accounts 561.1 through 561.4, and Account 581, Load Dispatching-Distribution.

16. In part 101, Operation and Maintenance Expense Accounts, Account 561, Load Dispatching (Major only) is removed.

17. In part 101, Operation and Maintenance Expense Accounts, new expense accounts 561.1, 561.2, 561.3, 561.4, 561.5, 561.6, 561.7, 561.8, 569.1, 569.2, 569.3, 575.1,575.2, 575.3, 575.4 575.5, 575.6, 575.7, 575.8, 576.1, 576.2, 576.3, 576.4 and 576.5 are added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

561.1 Load dispatch-Reliability.

This account shall include the cost of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to manage the reliability coordination function as specified by the North American Electric Reliability Council (NERC) and individual reliability organizations. These activities shall include performing current and next day reliability analysis. This account shall include the costs incurred to calculate load forecasts, and performing contingency analysis.

561.2 Load dispatch-Monitor and operate transmission system.

This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to monitor, assess and operate the power system and individual transmission facilities in real-time to maintain safe and reliable operation of the transmission system. This account shall also include the expense incurred to manage transmission facilities to maintain system reliability and to monitor the real-time flows and direct actions according to regional plans and tariffs as necessary.

ITEMS

1. Receive and analyze outage requests
2. Reschedule outage plans
3. Monitor solution quality field data values, providing model updates to NERC and coordinating network model changes across all systems
4. Conduct operating training related to NERC certification
5. Monitor generation resources and communicate expected dispatch actions
6. Ensure ancillary service requirements are met
7. Directing switching
8. Controlling system voltages
9. Obtaining reports on the weather and special events
10. Preparing operating reports and data for billing and budget purposes

561.3 Load dispatch-Transmission service and scheduling.

This account shall include the costs of labor, materials used and expenses incurred by a regional transmission service provider or other transmission provider to process hourly, daily, weekly and monthly transmission service requests using an automated system such as an Open Access Same-Time Information System (OASIS). It shall also include the expenses incurred to operate the automated transmission service request system and to monitor the status of all scheduled energy transactions.

561.4 Scheduling, system control and dispatching services.

This account shall include the costs billed to the transmission owner, load serving entity or generator for scheduling, system control and dispatching service. Include in this account service billings for system control to maintain the reliability of the transmission area in accordance with reliability standards, maintaining defined voltage profiles, and monitoring operations of the transmission facilities.

561.5 Reliability, planning and standards development.

This account shall include the cost of labor, materials used and expenses incurred for the system planning of the interconnected bulk electric transmission systems within a planning authority area.

ITEMS

1. Developing and maintaining transmission system models to evaluate transmission system performance.

2. Maintaining and applying methodologies and tools for the analysis and simulation of the transmission systems for the assessment and development of transmission expansion plans.

3. Assessing, developing and documenting transmission expansion plans.

4. Maintaining transmission system models (steady-state, dynamics, and short circuit).

5. Collecting transmission information and transmission facility characteristics and ratings.

6. Notifying participants of any planned transmission changes that may impact their facilities.

7. Developing and reporting on transmission expansion plans for assessment and compliance with reliability standards.

8. Developing reliability standards for the planning and operation of the interconnected bulk electric transmission systems that serve the United States, Canada, and Mexico.

9. Developing criteria and certification procedures for reliability authorities, transmission operators and others.

10. Outside services employed

Note: The cost of supervision, customer records and collection expenses, administrative and general salaries, office supplies and expenses, property insurance, injuries and damages, employee pension and benefits, regulatory commission expenses, general advertising, and rents shall be charged to the customer accounts, service, and administrative and general expense accounts contained in the Uniform System of Accounts.

561.6 Transmission service studies.

This account shall include the cost of labor, materials used and expenses incurred to conduct transmission services studies for proposed interconnections with the transmission system. Detailed records shall be maintained for each study undertaken and all reimbursements received for conducting such a study.

561.7 Generation interconnection studies.

This account shall include the cost of labor, materials used and expenses incurred to conduct generation interconnection studies for proposed interconnections with the transmission system. Detailed records shall be maintained for each study undertaken and all reimbursements received for conducting such a study.

561.8 Reliability planning and standards development services.

This account shall include the costs billed to the transmission owner, load serving entity, or generator for system planning of the interconnected bulk electric transmission system. Include also the costs billed by the regional transmission service provider for system reliability and resource planning to develop long-term strategies to meet customer demand and energy requirements. This account shall also include fees and expenses for outside services incurred by the regional transmission service provider and billed to the load serving entity, transmission owner or generator.

* * * * *

569.1 Maintenance of computer hardware.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of computer hardware serving the transmission function.

569.2 Maintenance of computer software.

This account shall include the cost of labor, materials used and expenses incurred for annual computer software license renewals, annual software update services and the cost of ongoing support for software products serving the transmission function.

ITEMS

1. Telephone support
2. Onsite support
3. Software updates and minor revisions

569.3 Maintenance of communication equipment.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of communication equipment serving the transmission function.

569.4 Maintenance of miscellaneous regional transmission plant.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of miscellaneous regional transmission plant serving the transmission function.

* * * * *

575.1 Operation Supervision.

This account shall include the cost of labor and expenses incurred in the general supervision and direction of the regional energy markets.

575.2 Day-ahead and real-time market administration.

This account shall include the cost of labor, materials used and expenses incurred to facilitate the Day-Ahead and Real-Time markets. This account shall also include the costs incurred to manage the real-time deployment of resources to meet generation needs and to provide capacity adequacy verification. Include in this account the costs incurred to maintain related sections of the tariff, market rules, operating procedures, and standards and coordinating with neighboring areas.

ITEMS

1. Consultant fees and expenses
2. System record and report forms
3. Meals, traveling and incidental expenses

Note: The cost of supervision, customer records and collection expenses, administrative and general salaries, office supplies and expenses, property insurance, injuries and damages, employee pension and benefits, regulatory commission expenses, general advertising, and rents shall be charged to the customer accounts, service, and administrative and general expense accounts contained in the Uniform System of Accounts.

575.3 Transmission rights market administration.

This account shall include the cost of labor, materials used and expenses incurred to manage the allocation and auction of transmission rights.

575.4 Capacity market administration.

This account shall include the cost of labor, materials used and expenses incurred to manage the allocation of capacity rights.

575.5 Ancillary services market administration.

This account shall include the cost of labor, materials used and expenses incurred to manage all other ancillary services market functions.

575.6 Market monitoring and compliance.

This account shall include the cost of labor, materials used and expenses incurred to review market data and operational decisions for compliance with market rules. It shall also include the costs incurred to interface with external market monitors.

575.7 Market administration, monitoring and compliance services.

This account shall include the costs billed to the transmission owner, load serving entity or generator for market administration, monitoring and compliance services.

575.8 Rents.

This account shall include all rents of property of others used, occupied, or operated in connection with market administration and monitoring. (See operating expense instruction 3.)

576.1 Maintenance of structures and improvements.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of structures used in market administration and monitoring. (See operating expense instruction 2.)

576.2 Maintenance of computer hardware.

The account shall include the cost of labor, materials used and expenses incurred in the maintenance of computer hardware used in market administration and monitoring.

576.3 Maintenance of computer software.

This account shall include the cost of labor, materials used and expenses incurred for annual computer software license renewals, annual software update services and the cost of ongoing support for software products used in market administration and monitoring.

ITEMS

1. Telephone support
2. Onsite support
3. Software updates and minor revisions

576.4 Maintenance of communication equipment.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of communication equipment used in market administration and monitoring.

576.5 Maintenance of miscellaneous market operation plant.

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of miscellaneous market operation plant used in market administration and monitoring.

Appendix A

List of Commenters

1 American Public Power Association (APPA)
2 Arizona Public Service Company (APS)
3 Cinergy Services, Inc. (Cinergy)[101]
4 City of Santa Clara, California \dba Silicon Valley Power (City of Santa Clara)
5 Electricity Consumers Resource Council (ELCON)
6 The Independent Electricity System Operator of Ontario (IESO)
7 Indicated New York Transmission Owners (Indicated NYTOs)[102]
8 International Transmission Company (International Transmission)
9 The Iowa Utilities Board (Iowa Board)
10 ISO/RTO Council[103]
11 FirstEnergy Service Company (FirstEnergy)[104]
12 Madison Gas & Electric Company (MGE)
13 Massachusetts Municipal Wholesale Electric Company (MMWEC)

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[101] Cinergy Services filed comments on behalf of its franchised utility affiliates, The Cincinnati Gas & Electric Company, PSI Energy, Inc., and The Union Light, Heat and Power Company (collectively, Cinergy)

[102] Indicated NYTOs includes: Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; LIPA; New York Power Authority; New York Electric & Gas Corporation; Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

[103] ISO/RTO Council includes: The Alberta Electric System Operator; California Independent System Operators, Inc.; Electric Reliability Council of Texas; the Independent Electricity System of Ontario, Inc.; ISO New England, Inc.; Midwest Independent Transmission System Operators, Inc; New York Independent System Operators, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool.

[104] FirstEnergy filed on behalf of its electric utility operating company affiliates: Ohio Edison Company; The Toledo Edison Company; the Cleveland Electric Illuminating Company; Pennsylvania Power Company; American Transmission System, Inc; Jersey Central Power & Light Company; Pennsylvania Electric Company; and Metropolitan Edison Company.

14 Midwest ISO Transmission Owners[105]
15 National Rural Electric Cooperative Association (NRECA)
16 National Grid USA
17 The New England Power Pool Participants Committee (NEPOOL Participants Committee)
18 NiSource Inc. (NiSource)
19 Southern California Edison Company (SCE)
20 The Transmission Agency of Northern California (TANC)
21 Transmission Access Policy Study Group (TAPS)
22 Wisconsin Electric Power Company (Wisconsin Electric)

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[105] The Midwest ISO Transmission Owners for this filing consist of: Ameren Services Company, as agent for Union Electric Company d/b/a AmerenUE, Central Illinois Public Service Company d/b/a AmerenCIPS, Central Illinois Light Co. d/b/a AmerenCilco, and Illinois Power Company d/b/a AmerenIP; Alliant Energy Corporate Services, Inc. on behalf of its operating company affiliate Interstate Power and Light Company (f/k/a IES Utilities Inc. and Interstate Power Company); American Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp.; Aquila, Inc. d/b/a Aquila Networks (f/k/a Utilicorp United, Inc.); City Water, Light & Power (Springfield, IL); Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; LG&E Energy LLC (for Louisville Gas and Electric Company and Kentucky Utilities Company); Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company and Northern States Power Company (Wisconsin), subsidiaries of Xcel Energy Inc.; Northwestern Wisconsin Electric Company; Otter Tail Corporation d/b/a Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); and Wabash Valley Power Association, Inc.

Planning Year 2025-2026 Loss of Load Expectation Study Report

The Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report details the various inputs, assumptions, and methodologies utilized in both the probabilistic and the power flow analyses to establish the seasonal Planning Reserve Margin (PRM), Local Reliability Requirement (LRR), and Capacity Import/Export Limit (CIL/CEL) values.

Highlights

- Summer, Winter, and Spring Planning Reserve Margin (PRM) decreased from Planning Year 2024-2025, while the Fall PRM increased slightly.

- In the Planning Year 2025-2026 study, significant year-over-year differences in wind and solar Effective Load Carrying Capability (ELCC) were observed for the Fall, Winter, and Spring seasons.

- An enhanced load development process and improved outage rates were the primary factors for the changes in the Planning Year 2025-2026 results. Additionally, shifting risk hours and ongoing changes to the generation fleet impacted this year's results.

MISO

Schedule NLP-SR4

misoenergy.org

Contents

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Executive Summary

In preparation for the annual Planning Resource Auction (PRA), MISO conducts an annual Loss of Load Expectation (LOLE) Study to determine Resource Adequacy Requirements for the upcoming Planning Year. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Review processes played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG), the Resource Adequacy Subcommittee (RASC), and the Independent Market Monitor (IMM) for their assistance and input in this year's study.

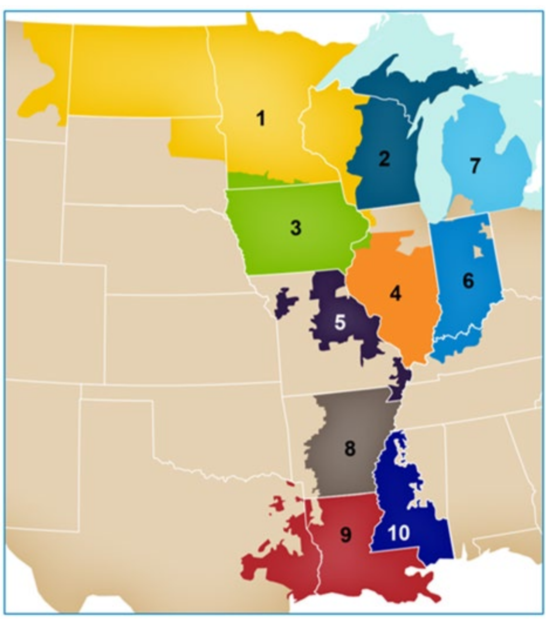
The seasonal Planning Reserve Margin (PRM) values determined through the Planning Year 2025-2026 LOLE study are provided in the table below.

Planning Year 2025-2026 Seasons	Summer 2025	Fall 2025	Winter 2025-2026	Spring 2026
MISO PRM UCAP	7.9%	14.9%	18.4%	25.3%

Table ES-1: Planning Reserve Margin Summary and Comparison

This study also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season are also determined. These quantities are described in greater detail in Section 4.3.

MISO is divided into 10 Local Resource Zones (LRZs) as shown in the figure and table below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-2: Map of MISO Local Resource Zones
Table ES-2: Local Balancing Authority to Local Resource Zone Designations

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Tables ES-3 through ES-6 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Capacity Import Limit (CIL) (MW)	6,025	4,370	5,518	8,649	4,117	8,650	3,579	2,522	4,872	4,474
Capacity Export Limit (CEL) (MW)	3,991	4,614	4,655	4,460	3,939	6,881	5,716	6,345	3,775	2,097

Table ES-3: Initial Planning Resource Auction Deliverables — Summer 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Capacity Import Limit (CIL) (MW)	5,690	6,537	7,766	7,908	4,679	8,970	5,125	5,870	5,242	4,508
Capacity Export Limit (CEL) (MW)	6,165	4,259	5,862	4,174	5,816	5,173	5,158	4,024	3,672	3,164

Table ES-4: Initial Planning Resource Auction Deliverables — Fall 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Capacity Import Limit (CIL) (MW)	5,575	6,435	5,853	7,353	4,922	7,936	4,762	3,534	4,995	3,458
Capacity Export Limit (CEL) (MW)	3,591	4,793	7,412	4,635	4,814	1,665	5,712	3,681	3,041	2,028

Table ES-5: Initial Planning Resource Auction Deliverables — Winter 2025-2026

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Capacity Import Limit (CIL) (MW)	6,398	6,439	7,784	8,272	4,453	9,491	5,166	6,250	5,370	4,365
Capacity Export Limit (CEL) (MW)	5,283	6,119	5,981	4,981	5,797	6,391	5,499	3,559	3,631	3,072

Table ES-6: Initial Planning Resource Auction Deliverables — Spring 2026

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1 MISO System Planning Reserve Margin

1.1 LOLE Study Process Overview

In compliance with Module E-1 of the Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2025-2026, the system Planning Reserve Margin Unforced Capacity (PRM UCAP) and the Local Reliability Requirement (LRR) for each Local Resource Zone.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL), and Capacity Export Limits (CEL). ZIA and controllable exports are used in conjunction with the Local Reliability Requirement (LRR) values to establish the seasonal Local Clearing Requirement (LCR) values in the Planning Resource Auction (PRA). Seasonal CIL and CEL values determine the maximum amount of capacity that can be imported or exported respectively to or from a zone. These variables are covered in Section 4 of this report.

The PY 2025-2026 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2025-2026 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and controllable exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Controllable Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective Planning Reserve Margin Requirement (PRMR) for each season of the 2025-2026 Planning Resource Auction will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2024. The ZIA, ZEA, CIL, and CEL values are subject to updates in March 2025 based on changes to

[1] https://www.misoenergy.org/legal/tariff
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exports of MISO resources to non-MISO load, changes to pseudo-tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1.1 Study Improvements

The Planning Year 2025-2026 LOLE study incorporated the following improvements:

- **SERVM Improvements:** Enhancements made to SERVM resulted in reliability improvements driven primarily by a more realistic dispatch of demand response and battery storage resources.
- **Improved Load Development Process:** This enhanced process aimed to better account for the correlation between load and weather, and to resolve unrealistic high-risk hours in the early mornings of the Winter season that were identified through concerns expressed by the IMM last year. The PY 2025-2026 load development process also better captured the relationship between higher load and temperature values that establishes a stronger representation of load behavior at more extreme temperatures than the prior load development process. Additional information on this load development process may be found in Section 3.4 of this study report.
- **Expanded consideration of outages driven by extreme cold temperatures**: The accounting of additional forced outages during extreme cold temperatures in the Fall, Winter, and Spring seasons was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized resource-specific five-year average EFORd values based on historical GADS data, which were updated from annualized EFORd to seasonalized EFORd in the PY 2023-2024 LOLE study. The cold weather outage adder was included in the LOLE model, starting with the PY 2024-2025 LOLE study, to better capture the historic seasonal availability of thermal resources during extreme cold temperatures. This was expanded upon in the PY 2025-2026 LOLE study to include the Fall and Spring seasons.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of additional forced outages increases as temperatures decrease based on the relationship between forced outages and temperature determined from historical GADS and weather data. The modeling of additional forced outages in the Fall, Winter, and Spring seasons due to the adder induces a higher volume of forced outages in the model beyond just the average Fall, Winter, and Spring EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Unforced Capacity resulting from additional extreme cold weather outages was addressed in the most recent PRM and LRR calculations for the Fall and Spring seasons. A comparative probabilistic analysis (with and without the cold weather outage adder) quantified the impact of modeling the cold weather outage adder profiles on the system-wide requirements for each season. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations. The comparative probabilistic analysis resulted in the largest effects for the Winter season and minimal effects for the Fall and Spring seasons. Summer was not affected by these outages.

1.2 Planning Year 2025-2026 MISO Planning Reserve Margin Results

For Planning Year 2025-2026, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 7.9 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 1-2).

MISO Planning Reserve Margin (PRM)	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring	Formula Key
MISO System Peak Demand (MW)	123,576	108,109	103,910	98,680	[A]
Installed Capacity (ICAP) (MW)	141,908	142,746	147,430	144,513	[B]
Unforced Capacity (UCAP) (MW)	132,389	131,554	126,573	131,289	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[F]
Adjustment to UCAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	142,934	135,472	144,058	136,937	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	133,363	124,179	123,058	123,598	[I] = [C]+[E]+[G]
MISO PRM ICAP	**15.7%**	**25.3%**	**38.6%**	**38.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**7.9%**	**14.9%**	**18.4%**	**25.3%**	[K]=[I]-[A]/[A]

Table 1-2: Planning Year 2025-2026 MISO System Planning Reserve Margins

1.2.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 1-3. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE. Loss of Load Hours is the number of hours during a given time period where demand exceeds generation. Like LOLE, LOLH is only measured on the daily peak hour. Expected Unserved Energy is the magnitude of the shortfall when demand exceeds generation and is measured on all hours of simulation.

MISO LOLE Statistics	
Loss of Load Expectation (LOLE) [days/year]	0.100
Loss of Load Hours (LOLH) [hours/year]	0.252
Expected Unserved Energy (EUE) [megawatt-hours/year]	626.161

Table 1-3: Additional Risk Metric Statistics

1.3 Comparison of PRM Targets Across 10 Years

Figure 1-1 compares the PRM UCAP values over the last 10 Planning Years. The last three data points show the Summer PRM UCAP values following FERC's acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

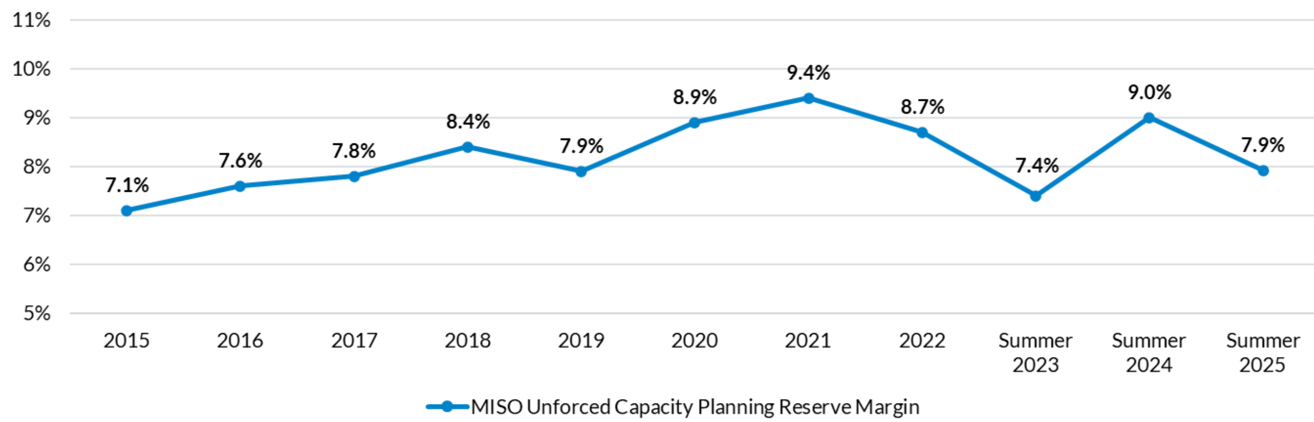

Figure 1-1: Comparison of UCAP PRM Targets Across 10 Years

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1.4 Comparison of Planning Year 2024-2025 to Planning Year 2025-2026

Multiple sensitivity analyses were performed to independently quantify the year-over-year changes to the seasonal Planning Reserve Margin (PRM) values driven by various model improvements or model data replacement. The incremental impact to the seasonal PRM values from Planning Year 2024-2025 to Planning Year 2025-2026 due to specific changes to the LOLE model are shown in the waterfall charts below (Figure 1-2, Figure 1-3, Figure 1-4, and Figure 1-5). The following subsections provide more details around each of the sensitivities.

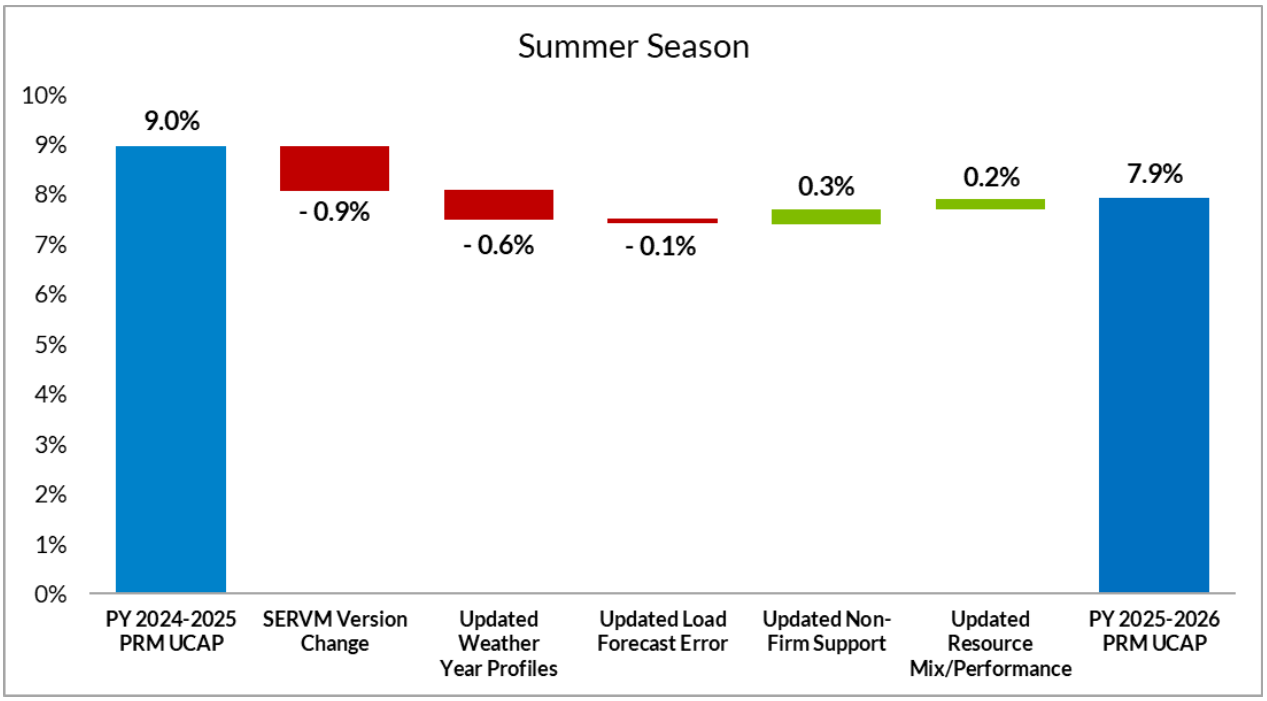

Figure 1-2: Waterfall Chart of Summer PRM UCAP from PY 2024-2025 to PY 2025-2026

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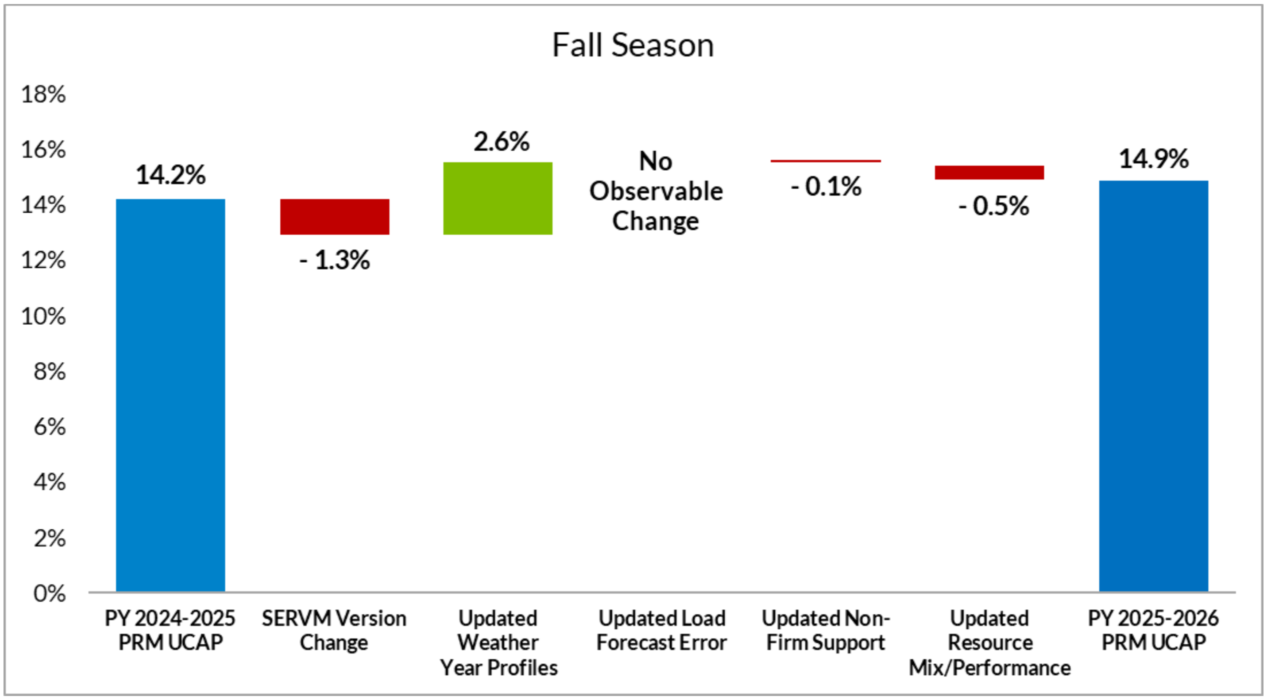

Figure 1-3: Waterfall Chart of Fall PRM UCAP from PY 2024-2025 to PY 2025-2026

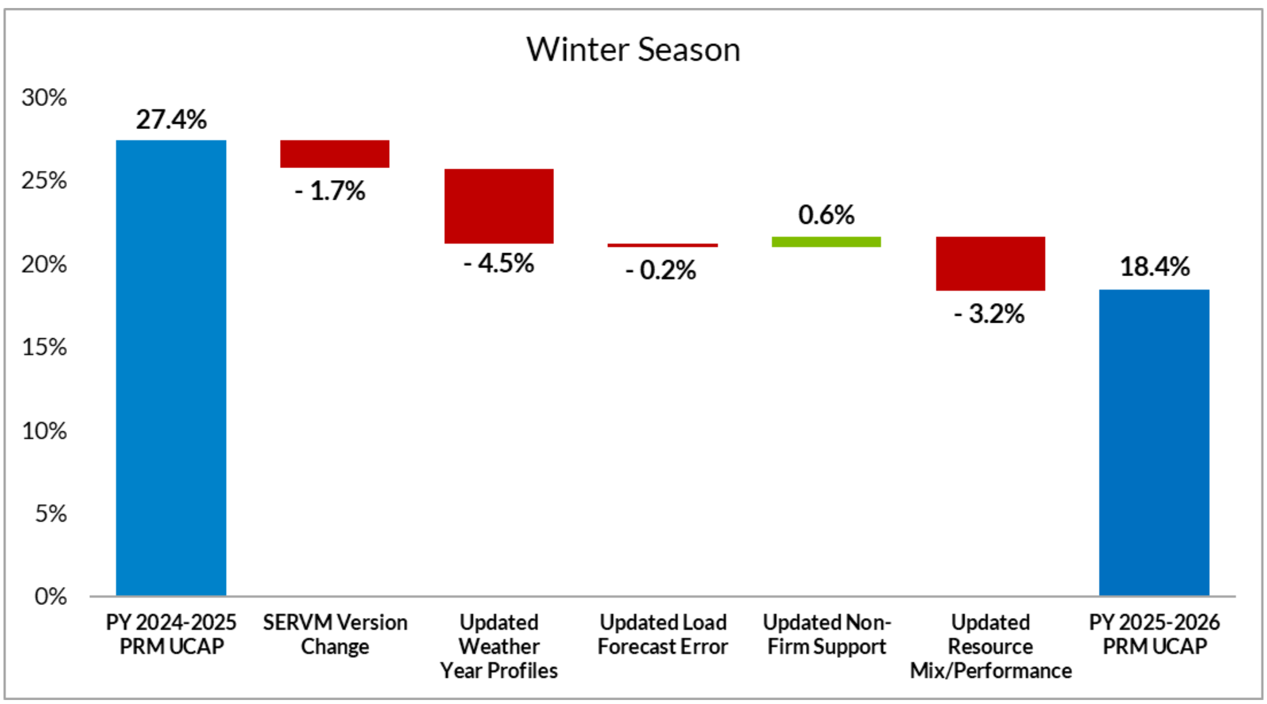

Figure 1-4: Waterfall Chart of Winter PRM UCAP from PY 2024-2025 to PY 2025-2026

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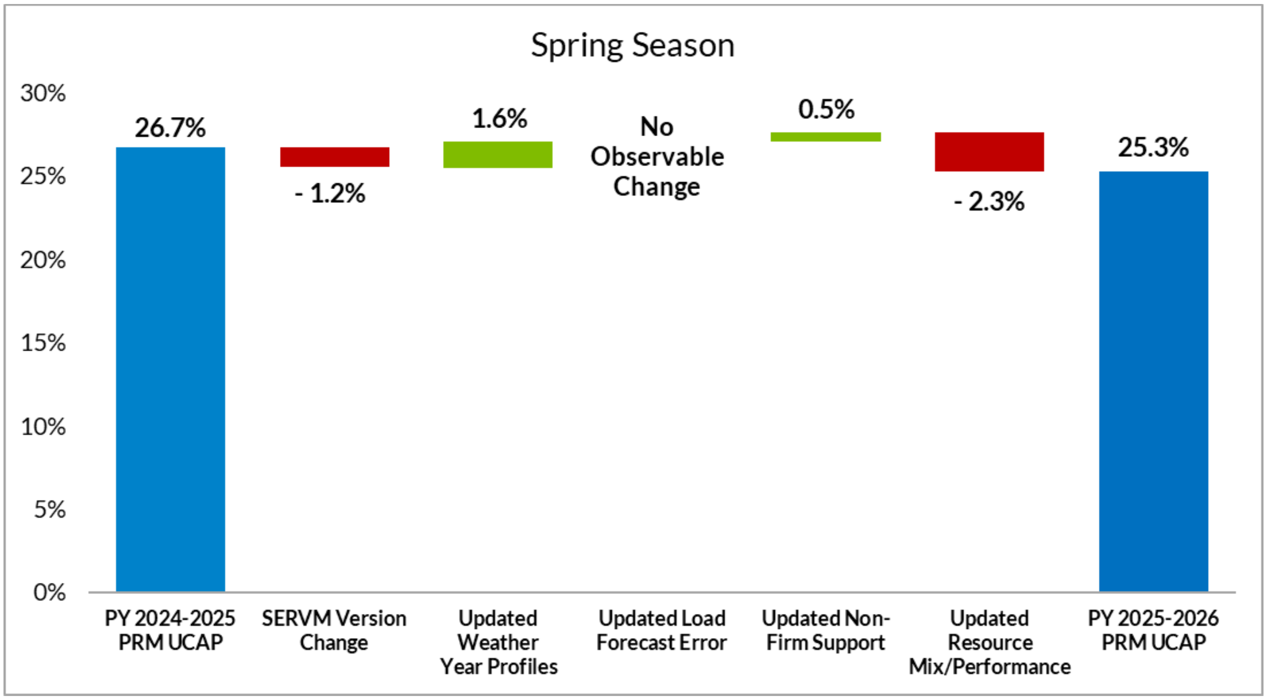

Figure 1-5: Waterfall Chart of Spring PRM UCAP from PY 2024-2025 to PY 2025-2026

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1.4.1 Waterfall Chart Details

1.4.1.1 SERVM Improvements

Enhancements made to SERVM for the Planning Year 2025-2026 LOLE study resulted in reliability improvements driven primarily by a more realistic dispatch of demand response and storage resources. Version 9 of SERVM was used in this year's LOLE study.

1.4.1.2 Updated Weather Year Profiles

Every year during the annual refresh of the LOLE model, the oldest weather year is removed and a new weather year is added. In this sensitivity category, MISO analyzes the impacts of all updated hourly profiles that are tied to specific weather years, including profiles for load, wind generation, solar generation, and cold weather outage adders. Since all these variables are tied to specific weather years in the model, it is not possible to isolate the individual impacts of these variables.

1.4.1.3 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is independent of specific weather years and is the next input dataset that is replaced in the year-over-year LOLE model refresh. More information on the modeling of non-firm support can be found in Section 3.5.

1.4.1.4 Updated Resource Mix / Performance

Changes in resource capabilities from Planning Year 2024-2025 are driven by updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, replacements, and general changes in the MISO resource fleet.

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2 Local Resource Zone Analysis – LRR Results

2.1 Planning Year 2025-2026 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2025-2026 on a seasonal basis (Table 2-1, Table 2-2, Table 2-3, and Table 2-4). The Unforced Capacity (UCAP) values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria are met. LRR is the summation of the zone's total capacity and adjustment to capacity needed to achieve the seasonal LOLE criteria. The LRR is then divided by each LRZ's forecasted seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2025-2026 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2025-2026 PRA to determine each LRZ's LRR. The MISO system-wide and zonal peak demand timestamps for all 30 years modeled in the LOLE study are shown in Table 2-5. The peak demand timestamps are subject to the load development process and are not necessarily the actual historical peak days and times.

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Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Summer 2025											
Installed Capacity (ICAP) (MW)	20,621	14,053	11,537	9,290	6,452	17,290	22,708	11,194	22,675	6,086	[A]
Unforced Capacity (UCAP) (MW)	19,636	13,339	11,047	8,726	5,925	15,581	21,136	10,453	21,046	5,501	[B]
Adjustment to UCAP (MW)	1,733	1,067	2,527	2,520	4,318	6,570	2,708	956	3,570	1,975	[C]
Local Reliability Requirement (LRR) UCAP (MW)	21,369	14,406	13,574	11,246	10,243	22,151	23,844	11,408	24,616	7,476	[D]=[B]+[C]
Peak Demand (MW)	17,889	12,694	10,295	8,786	7,873	17,555	20,953	8,448	21,676	5,166	[E]
LRR UCAP per-unit of LRZ Peak Demand	**119.5%**	**113.5%**	**131.8%**	**128.0%**	**130.1%**	**126.2%**	**113.8%**	**135.0%**	**113.6%**	**144.7%**	[F]=[D]/[E]

Table 2-1: Planning Year 2025-2026 LRZ Local Reliability Requirements for Summer 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Fall 2025											
Installed Capacity (ICAP) (MW)	20,658	14,203	12,874	9,171	6,442	17,232	22,539	10,910	22,618	6,099	[A]
Unforced Capacity (UCAP) (MW)	19,554	13,196	12,295	8,486	5,883	15,652	20,755	10,184	20,175	5,374	[B]
Adjustment to UCAP (MW)	165	50	1,590	1,565	3,785	5,154	1,937	888	3,449	1,908	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,719	13,246	13,885	10,051	9,668	20,806	22,692	11,072	23,624	7,282	[D]=[B]+[C]
Peak Demand (MW)	15,313	10,839	9,034	7,616	7,084	15,859	18,085	7,537	19,721	4,676	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.8%**	**122.2%**	**153.7%**	**132.0%**	**136.5%**	**131.2%**	**125.5%**	**146.9%**	**119.8%**	**155.7%**	[F]=[D]/[E]

Table 2-2: Planning Year 2025-2026 LRZ Local Reliability Requirements for Fall 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Winter 2025-2026											
Installed Capacity (ICAP) (MW)	20,600	13,959	12,919	9,288	6,879	17,115	23,377	12,008	24,649	6,635	[A]
Unforced Capacity (UCAP) (MW)	18,563	12,282	11,640	6,065	4,655	13,672	21,359	10,503	22,163	5,671	[B]
Adjustment to UCAP (MW)	995	950	1,950	3,023	4,152	5,950	-840	1,278	3,279	1,617	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,558	13,232	13,591	9,088	8,806	19,622	20,519	11,781	25,442	7,288	[D]=[B]+[C]
Peak Demand (MW)	15,442	9,781	8,328	7,664	7,023	15,729	14,177	7,524	19,613	4,477	[E]
LRR UCAP per-unit of LRZ Peak Demand	**126.7%**	**135.3%**	**163.2%**	**118.6%**	**125.4%**	**124.7%**	**144.7%**	**156.6%**	**129.7%**	**162.8%**	[F]=[D]/[E]

Table 2-3: Planning Year 2025-2026 LRZ Local Reliability Requirements for Winter 2025-2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Spring 2026											
Installed Capacity (ICAP) (MW)	19,862	14,049	12,380	9,293	7,423	17,188	22,881	11,694	23,337	6,406	[A]
Unforced Capacity (UCAP) (MW)	18,613	13,073	11,555	7,865	5,961	15,273	20,822	10,613	21,646	5,869	[B]
Adjustment to UCAP (MW)	990	600	1,540	1,910	3,470	4,948	668	199	3,333	1,963	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,604	13,673	13,094	9,775	9,431	20,221	21,490	10,811	24,979	7,832	[D]=[B]+[C]
Peak Demand (MW)	15,285	10,270	8,246	6,537	6,465	14,570	16,293	6,813	19,333	4,381	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.3%**	**133.1%**	**158.8%**	**149.5%**	**145.9%**	**138.8%**	**131.9%**	**158.7%**	**129.2%**	**178.8%**	[F]=[D]/[E]

Table 2-4: Planning Year 2025-2026 LRZ Local Reliability Requirements for Spring 2026

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Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1994	7/6/94 16:00	8/25/94 17:00	8/25/94 16:00	7/19/94 18:00	7/6/94 17:00	1/18/94 15:00	1/19/94 8:00	7/6/94 15:00	1/18/94 21:00	7/3/94 18:00	1/18/94 20:00
1995	7/12/95 17:00	7/13/95 19:00	7/13/95 16:00	7/12/95 16:00	7/12/95 17:00	8/18/95 19:00	7/14/95 19:00	7/14/95 14:00	7/28/95 17:00	7/11/95 18:00	7/28/95 16:00
1996	8/6/96 16:00	7/18/96 16:00	8/14/96 16:00	7/18/96 17:00	7/18/96 18:00	7/18/96 19:00	2/2/96 19:00	8/7/96 16:00	6/30/96 21:00	2/5/96 6:00	7/3/96 16:00
1997	7/14/97 17:00	7/16/97 19:00	7/16/97 17:00	7/25/97 17:00	7/18/97 17:00	7/18/97 19:00	7/14/97 16:00	7/14/97 17:00	7/24/97 17:00	1/17/97 8:00	7/24/97 17:00
1998	7/20/98 16:00	7/14/98 18:00	7/14/98 18:00	7/20/98 19:00	7/21/98 18:00	7/21/98 16:00	7/21/98 17:00	7/21/98 15:00	7/7/98 15:00	8/28/98 18:00	8/27/98 18:00
1999	7/29/99 17:00	7/29/99 17:00	7/30/99 13:00	7/29/99 18:00	7/18/99 18:00	7/29/99 16:00	7/30/99 16:00	7/30/99 16:00	7/29/99 18:00	8/5/99 17:00	8/19/99 17:00
2000	8/31/00 17:00	7/8/00 17:00	7/14/00 16:00	9/2/00 17:00	7/10/00 18:00	8/17/00 18:00	8/9/00 18:00	6/10/00 16:00	7/20/00 14:00	8/26/00 17:00	8/30/00 16:00
2001	7/31/01 17:00	7/31/01 17:00	7/31/01 17:00	7/31/01 16:00	7/23/01 16:00	7/23/01 17:00	8/8/01 17:00	8/8/01 17:00	7/11/01 17:00	8/20/01 16:00	7/11/01 16:00
2002	7/8/02 16:00	7/1/02 19:00	7/18/02 15:00	7/8/02 18:00	7/9/02 17:00	7/23/02 17:00	8/23/02 16:00	7/1/02 16:00	8/6/02 17:00	7/18/02 16:00	7/9/02 17:00
2003	8/26/03 16:00	8/18/03 19:00	8/21/03 16:00	8/25/03 17:00	8/26/03 16:00	8/21/03 16:00	8/27/03 17:00	8/21/03 18:00	8/18/03 15:00	1/24/03 10:00	8/18/03 18:00
2004	7/22/04 16:00	7/21/04 19:00	6/8/04 14:00	7/13/04 18:00	7/22/04 16:00	7/22/04 17:00	12/24/04 10:00	6/9/04 12:00	7/14/04 17:00	8/1/04 16:00	7/31/04 16:00
2005	7/25/05 16:00	7/22/05 18:00	8/10/05 14:00	7/25/05 17:00	7/25/05 18:00	7/25/05 18:00	7/25/05 17:00	6/28/05 16:00	7/22/05 18:00	7/25/05 16:00	7/25/05 18:00
2006	7/31/06 17:00	7/31/06 17:00	7/31/06 18:00	7/19/06 19:00	7/31/06 17:00	8/2/06 18:00	7/31/06 17:00	7/31/06 17:00	7/21/06 15:00	12/8/06 8:00	7/18/06 17:00
2007	8/1/07 17:00	7/26/07 15:00	7/10/07 15:00	7/17/07 18:00	8/28/07 17:00	8/15/07 16:00	8/29/07 17:00	7/31/07 18:00	8/9/07 17:00	8/11/07 18:00	8/14/07 17:00
2008	7/16/08 17:00	7/29/08 18:00	7/17/08 15:00	7/17/08 17:00	7/18/08 17:00	7/18/08 17:00	8/23/08 16:00	8/24/08 12:00	8/2/08 18:00	7/26/08 16:00	7/28/08 17:00
2009	6/24/09 17:00	5/19/09 19:00	6/24/09 17:00	6/22/09 18:00	6/22/09 17:00	6/22/09 17:00	1/16/09 8:00	6/24/09 16:00	6/22/09 16:00	7/2/09 16:00	6/22/09 18:00

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Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/9/10 18:00	7/9/10 17:00	7/14/10 17:00	7/5/10 17:00	8/3/10 16:00	8/10/10 18:00	7/6/10 16:00	8/3/10 17:00	8/2/10 15:00	8/2/10 16:00
2011	7/20/11 17:00	7/18/11 18:00	7/20/11 15:00	8/2/11 17:00	8/24/11 14:00	9/1/11 16:00	9/2/11 18:00	7/21/11 15:00	8/3/11 18:00	8/18/11 16:00	7/13/11 16:00
2012	7/6/12 16:00	7/6/12 18:00	7/4/12 13:00	7/25/12 18:00	7/6/12 16:00	6/28/12 18:00	7/7/12 18:00	7/6/12 14:00	7/28/12 16:00	6/25/12 18:00	7/4/12 16:00
2013	7/19/13 16:00	8/27/13 18:00	7/19/13 14:00	8/30/13 17:00	8/30/13 17:00	8/30/13 16:00	8/30/13 16:00	7/19/13 14:00	8/30/13 17:00	8/5/13 17:00	7/30/13 17:00
2014	7/22/14 17:00	7/21/14 18:00	7/22/14 16:00	7/22/14 17:00	8/22/14 17:00	8/26/14 16:00	8/26/14 16:00	6/17/14 17:00	1/7/14 9:00	1/7/14 9:00	1/28/14 20:00
2015	7/28/15 17:00	7/14/15 18:00	8/3/15 17:00	7/13/15 15:00	7/28/15 18:00	7/28/15 17:00	9/8/15 16:00	7/29/15 16:00	7/29/15 16:00	1/8/15 7:00	7/30/15 15:00
2016	7/20/16 16:00	7/21/16 18:00	8/10/16 14:00	7/20/16 17:00	8/10/16 15:00	7/23/16 16:00	8/10/16 17:00	8/4/16 15:00	7/21/16 15:00	8/31/16 16:00	7/7/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	7/20/17 14:00	7/20/17 16:00	7/20/17 16:00	7/22/17 18:00	9/22/17 15:00	6/12/17 15:00	7/20/17 15:00	7/19/17 16:00	7/20/17 16:00
2018	7/5/18 14:00	6/29/18 15:00	8/15/18 15:00	8/3/18 16:00	8/16/18 16:00	8/6/18 16:00	1/16/18 19:00	7/5/18 14:00	1/2/18 8:00	8/14/18 16:00	1/17/18 9:00
2019	7/19/19 15:00	7/19/19 17:00	7/16/19 16:00	7/19/19 16:00	7/1/19 17:00	9/17/19 16:00	7/2/19 16:00	7/19/19 13:00	8/13/19 14:00	7/7/19 15:00	7/10/19 14:00
2020	7/18/20 16:00	7/8/20 18:00	7/8/20 16:00	8/26/20 15:00	8/26/20 15:00	7/11/20 16:00	8/25/20 15:00	7/3/20 16:00	7/18/20 15:00	7/10/20 16:00	7/18/20 14:00
2021	7/28/21 15:00	7/5/21 17:00	8/20/21 15:00	6/17/21 16:00	7/7/21 15:00	2/14/21 10:00	8/24/21 16:00	7/7/21 13:00	2/16/21 7:00	8/23/21 16:00	8/11/21 15:00
2022	6/21/22 16:00	6/20/22 16:00	6/21/22 16:00	8/2/22 16:00	7/20/22 16:00	7/22/22 16:00	7/5/22 16:00	6/21/22 16:00	7/26/22 15:00	6/23/22 17:00	6/21/22 16:00
2023	8/23/23 17:00	8/23/23 17:00	8/23/23 15:00	8/23/23 16:00	7/5/23 14:00	8/25/23 16:00	8/24/23 17:00	8/23/23 17:00	7/28/23 16:00	8/27/23 15:00	8/24/23 15:00

Table 2-5: Modeled Peak Demand Days/Hours by Local Resource Zone

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3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying resources, generator forced outages, generator planned maintenance outages, weather and economic uncertainty, and external support from neighboring regions.

Building the SERVM model is the most time-consuming task of the LOLE study. Several sensitivities are built to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO Planning Reserve Margin Unforced Capacity (PRM UCAP) and Local Reliability Requirement (LRR) values for each LRZ for future Planning Years one, four, and six.

3.1.1 Resource Inclusion

Planning Year 2025-2026

The Planning Year 2025-2026 LOLE study used converted capacity from the 2024-2025 PRA as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE study. For the PY 2025-2026 LOLE study, internal MISO CPNode resources that were excluded from the auction clearing process but were used to satisfy Resource Adequacy Requirements through a Fixed Resource Adequacy Plan (FRAP) or that offered and subsequently cleared the 2024-2025 PRA in any season were included in the LOLE model for all seasons. Resources that were on an approved Attachment Y suspension or retirement, or had an approved IMM exemption, were excluded from the LOLE model in their respective seasons. External resources were included for only the corresponding seasons in which they were included in a FRAP or offered in the 2024-2025 PRA.

Upcoming changes for Planning Year 2026-2027

In July 2024, MISO opened a formal feedback request with stakeholders to better define a set of criteria for resource inclusion within the LOLE model that would be implemented for the PY 2026-2027 LOLE study and beyond. From the feedback, it was determined that MISO will include resources for each season a resource is included in a FRAP or offered into the most recent PRA, with an exception for external resources. External resources will be included in the LOLE model for each season that an external resource is included in a FRAP or cleared in the most recent PRA. The rationale is that external resource offer behavior can differ from one year to the next, as they are not subject to economic withholding in MISO and do not have any obligation to serve MISO load if they do not make a commitment to do so through the PRA.

3.1.2 Effective Load Carrying Capability (ELCC)

Each year, MISO performs seasonal Effective Load Carrying Capability (ELCC) analyses for wind and solar resources to quantify their average capacity contribution to determine season-wide capacity values for use in the seasonal Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) calculations. Wind and solar generation is represented in the model with 30-year hourly capacity factor profiles.

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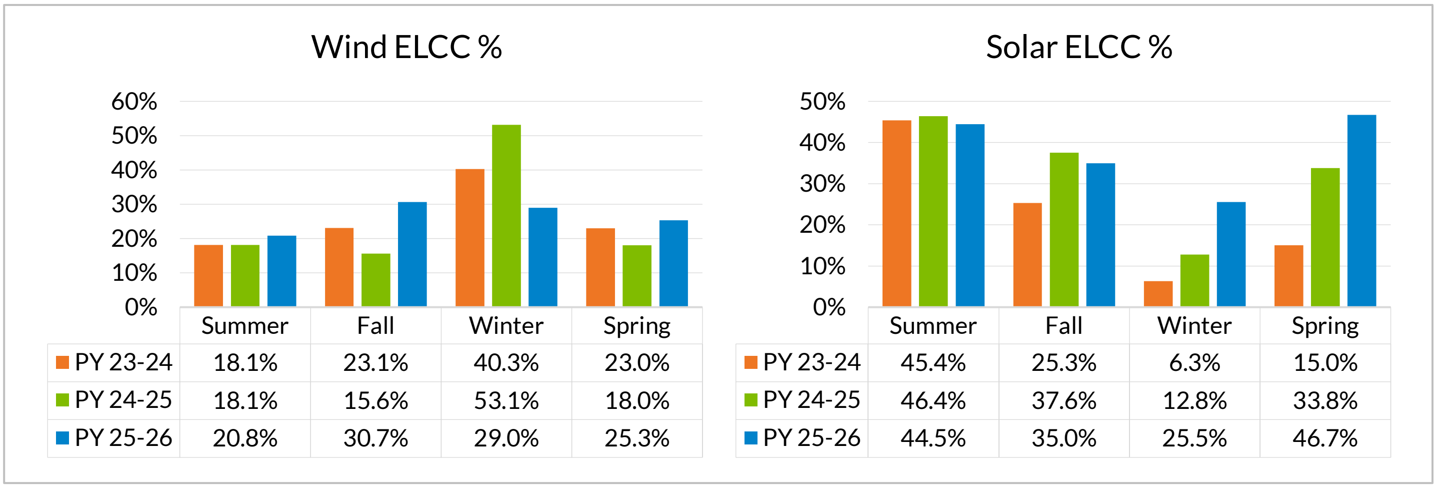
Seasonal wind ELCC determines the allocable Seasonal Accredited Capacity (SAC) for in-service CPNode wind resources for the prompt year PRA. Solar ELCC is not used for accreditation and is only used for calculating solar UCAP in the PRM and LRR equations. More details regarding wind and solar accreditation will be provided in the Planning Year 2025-2026 Wind and Solar Capacity Credit Report.

The Figure 3-1 below details the resulting LOLE study ELCC percentages over the last three Planning Years.



Wind ELCC %	Summer	Fall	Winter	Spring
PY 23-24	18.1%	23.1%	40.3%	23.0%
PY 24-25	18.1%	15.6%	53.1%	18.0%
PY 25-26	20.8%	30.7%	29.0%	25.3%

Solar ELCC %	Summer	Fall	Winter	Spring
PY 23-24	45.4%	25.3%	6.3%	15.0%
PY 24-25	46.4%	37.6%	12.8%	33.8%
PY 25-26	44.5%	35.0%	25.5%	46.7%

Figure 3-1: Planning Year 2025-2026 Wind and Solar ELCC Trends

Over the past several years, variability in the non-Summer season results have been observed for both wind and for solar. This is largely driven by the evolving resource mix within the MISO system and the resulting hours of risk for each year's model. Additionally, due to the Summer season having a higher LOLE criterion of 0.1 LOLE (or 1 day of loss of load in 10 years) at the system-wide level, there is a greater volume of impacted Loss of Load Hours (LOLH) in the Summer compared to the other seasons. This results in a larger sampling of wind and solar generation used in the ELCC analyses for Summer than in the other seasons.

Seasonal Drivers of Change from Planning Year 2024-2025 to Planning Year 2025-2026 are detailed below:

- **Summer**: The majority of the risk in the Planning Year 2024-2025 Summer season was observed in July. However, in Planning Year 2025-2026, there was an increase in prolonged risk observed in August. This resulted in wind generation impacting more hours during the Summer season and solar impacting slightly less as LOLH extended further into evening hours.
- **Fall**: In Planning Year 2024-2025, September was the only month that exhibited risk for the MISO system in the Fall season. In Planning Year 2025-2026, September risk increased and November demonstrated some morning and evening risk hours. Due to the shift in Fall risk hours, the number of hours where wind generation was able to be impactful increased, while the number of hours where solar could be impactful decreased.
- **Winter**: Changes in ELCC values for the Winter season were primarily driven by Planning Year 2025-2026 load development process enhancements. These enhancements shifted risk hours to later in the day where wind performed worse and solar was able to perform better during the full set of risk hours.
- **Spring**: During this season, MISO saw an increase in both wind and solar ELCC values. In Planning Year 2025-2026, Spring risk materialized during several evening hours in March, and the overall magnitude of risk increased in comparison with Planning Year 2024-2025. This allowed both wind and solar generation to become more impactful during hours of greater renewable output.

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3.2 MISO Generation

3.2.1 Thermal Units

All MISO internal thermal Planning Resources were modeled in the LRZ in which they are physically located, except for pseudo-tied resources. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2019 to December 2023) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least three consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than three consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis for the prompt Planning Year.

Pooled EFORd GADS Years	**2019-2023 (%)**	**2018-2022 (%)**	**2017-2021 (%)**	**2016-2020 (%)**	**2015-2019 (%)**	**2014-2018 (%)**
LOLE Study Planning Year	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized
Combined Cycle	5.26	5.92	5.54	5.85	5.52	5.70
Combustion Turbine (0-50 MW)	10.80	7.65	7.37	15.25	15.83	17.88
Combustion Turbine (50+ MW)	4.72	4.88	4.07	4.36	4.76	4.65
Diesel Engines	17.52	17.14	12.79	7.25	10.05	23.53
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-400 MW)	11.76	8.22	7.03	9.91	8.78	8.15
Steam - Coal (400-1,000 MW)	8.84	8.62	8.06	9.00	9.02	8.87
Steam - Gas	11.32	14.04	12.48	11.84	12.91	12.54
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	7.76	8.24	8.23	9.04	9.36	9.24

Table 3-1: Historical Class Average Forced Outage Rates

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Pooled EFORd GADS Years	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)
LOLE Study Planning Year 2025-2026	**Summer 2025**	**Fall 2025**	**Winter 2025-2026**	**Spring 2026**
Combined Cycle	5.26	6.95	5.16	5.93
Combustion Turbine (0-50 MW)	10.80	13.42	33.67	15.79
Combustion Turbine (50+ MW)	4.72	7.96	12.50	5.31
Diesel Engines	17.52	31.84	24.53	23.91
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-400 MW)	11.76	15.27	12.68	11.17
Steam - Coal (400-1,000 MW)	8.84	9.20	9.83	9.94
Steam - Gas	11.32	12.91	9.83	9.32
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	7.76	8.93	10.48	9.70

Table 3-2: Planning Year 2025-2026 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2024) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2025-2026 was excluded from the year-one analysis during the months in which the resource had been approved to be out of service. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2024). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model. In the LOLE model, resources with a signed and

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executed GIA receive a postponement to their anticipated in-service dates relative to the average delays per resource type observed by the Generation Interconnection team at MISO.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, and 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, and 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top eight seasonal coincident peaks for the last three Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 279 front-of-meter wind resources from 2013 to 2023, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis that is based on 30 weather years (1994 – 2023), synthetic shapes were developed by Astrapé for the 1994 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2023.

3.2.6 Demand Response

Demand response programs and their capabilities came from their corresponding registrations in the MECT tool. These resources were explicitly modeled as dispatch-limited resources and are the last set of resources dispatched by the model in an effort to avoid LOLE. Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Capacity

The following charts and tables below list the total Installed Capacity (ICAP) values by resource type and LRZ in the PY 2025-2026 LOLE model. Every July, MISO presents the preliminary capacity in the prompt year LOLE model at the LOLEWG and, starting with PY 2025-2026, MISO published the final ICAP values per zone and per season in its LOLE study report.

PY 2025-2026 ICAP MW, Summer											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,467	11,882	7,659	7,532	5,946	14,049	19,291	9,831	21,917	5,743	119,315
Demand Response	1,879	693	504	435	184	1,695	1,294	790	335	45	7,852
BTMG	1,460	339	603	310	97	351	1,073	17	20	104	4,373
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	205	113	10	0	142	208	15	64	229	0	986
Total	**26,507**	**15,810**	**21,782**	**11,564**	**6,774**	**19,078**	**25,917**	**11,810**	**22,892**	**6,427**	**168,561**

Table 3-3: Summer Total Installed Capacity by Resource Type and Local Resource Zone

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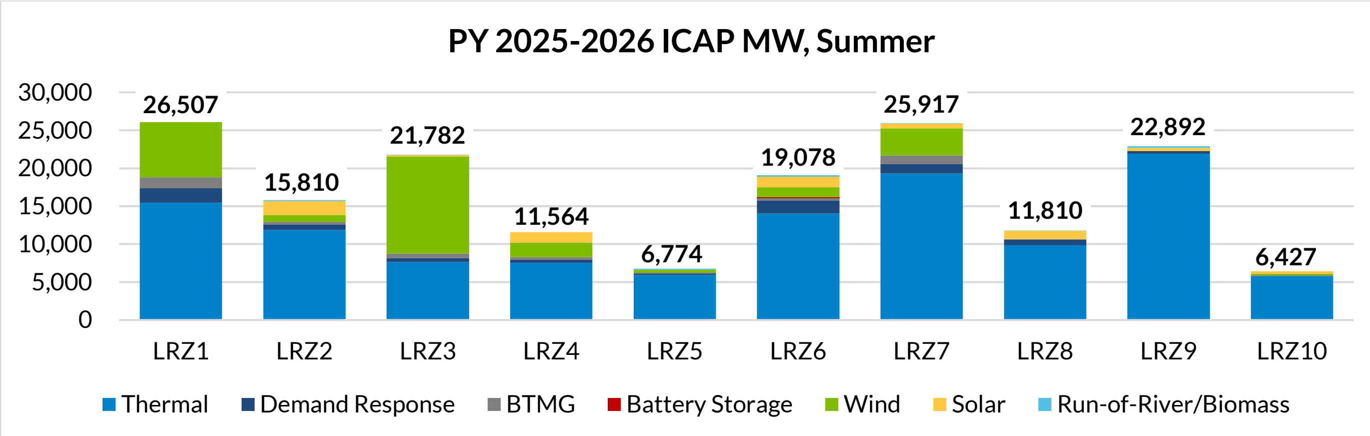

Figure 3-2: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Fall											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,477	12,095	7,765	7,357	6,043	14,203	19,506	9,884	22,001	5,812	120,142
Demand Response	1,435	719	512	440	47	1,515	627	586	334	5	6,220
BTMG	1,235	337	591	305	96	344	1,061	13	19	103	4,103
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	201	117	5	0	133	189	16	39	127	0	828
Total	**25,846**	**16,052**	**21,879**	**11,389**	**6,723**	**19,025**	**25,454**	**11,630**	**22,873**	**6,456**	**167,328**

Table 3-4: Fall Total Installed Capacity by Resource Type and Local Resource Zone

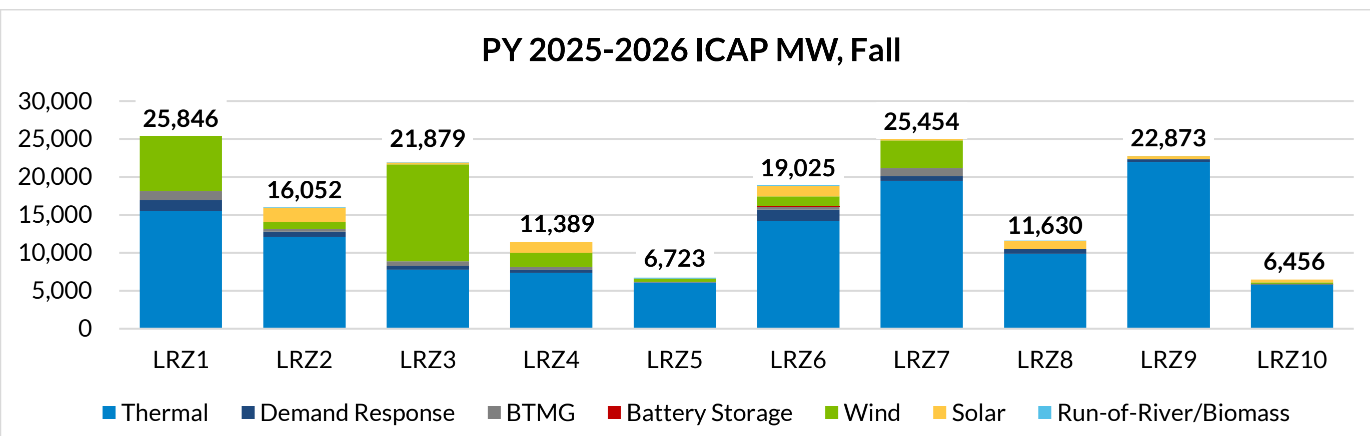

Figure 3-3: Fall Total Installed Capacity by Resource Type and Local Resource Zone

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PY 2025-2026 ICAP MW, Winter											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,955	12,056	8,142	7,739	6,504	14,392	20,471	10,561	23,999	6,384	126,202
Demand Response	1,560	701	391	325	33	1,407	660	1,088	334	5	6,504
BTMG	756	343	616	318	92	334	1,020	17	10	103	3,609
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	162	118	5	0	133	154	18	59	206	0	853
Total	**25,930**	**16,001**	**22,160**	**11,669**	**7,168**	**19,062**	**26,413**	**12,833**	**24,941**	**7,028**	**173,204**

Table 3-5: Winter Total Installed Capacity by Resource Type and Local Resource Zone

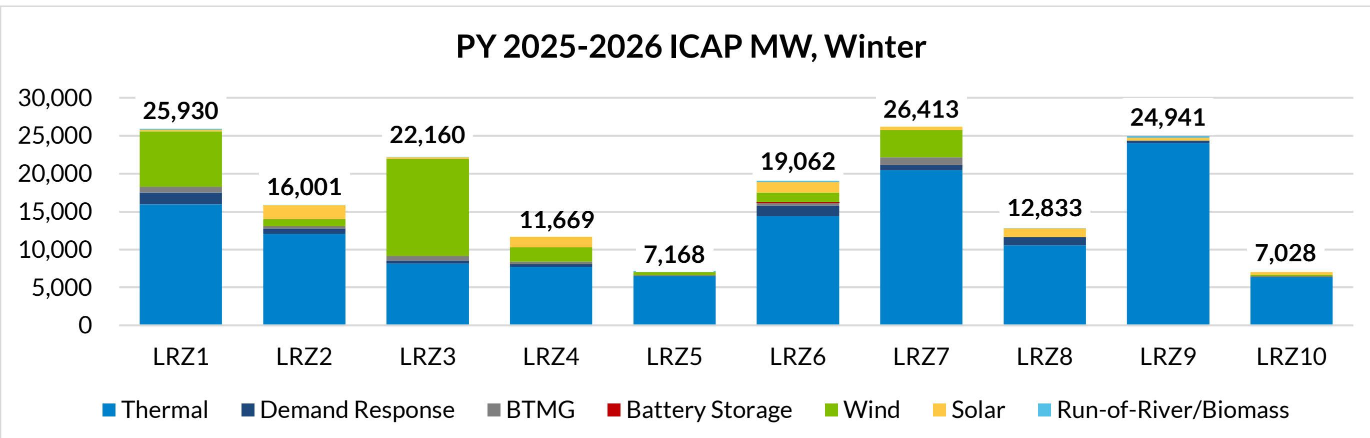

Figure 3-4: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Spring											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	14,895	11,695	7,928	7,470	6,960	13,910	19,783	10,072	22,307	5,959	120,980
Demand Response	1,404	719	387	386	57	1,522	670	887	334	5	6,370
BTMG	1,390	388	619	309	95	352	1,127	27	23	104	4,433
Battery Storage	0	0	50	0	0	301	0	0	25	0	376
Wind	7,285	893	12,982	1,897	406	1,281	3,606	0	0	185	28,535
Solar	212	1,891	224	1,390	180	1,393	788	1,383	867	626	8,953
Run-of-River/Biomass	229	138	4	0	124	129	20	62	243	0	949
Total	**25,415**	**15,724**	**22,195**	**11,451**	**7,822**	**18,888**	**25,994**	**12,432**	**23,799**	**6,878**	**170,596**

Table 3-6: Spring Total Installed Capacity by Resource Type and Local Resource Zone

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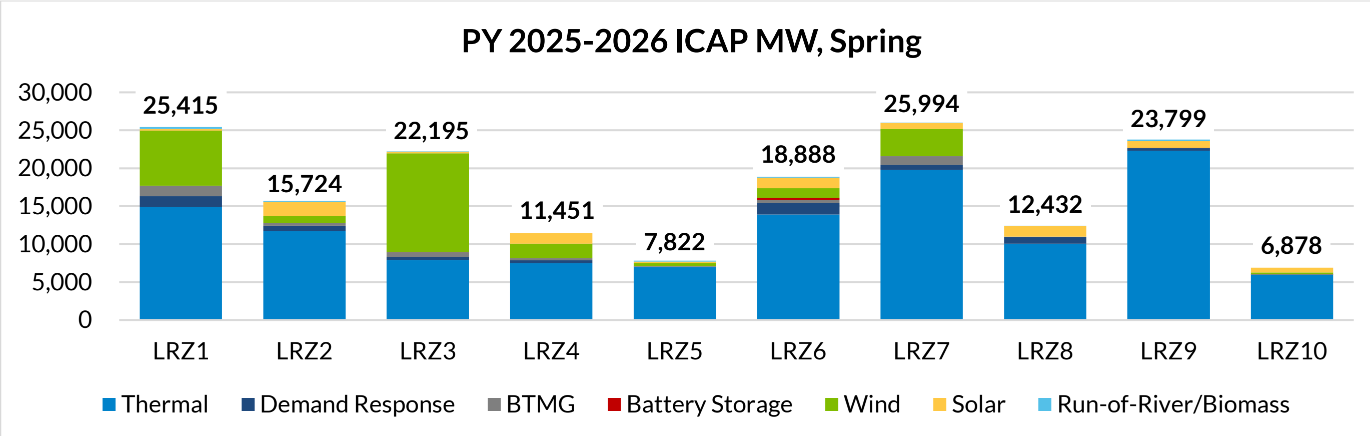

Figure 3-5: Spring Total Installed Capacity by Resource Type and Local Resource Zone

3.4 MISO Load Data

Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. At the request of stakeholders, MISO expanded its load data section to provide additional information about the LOLE study load development process.

The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability. Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30-year load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 1-2) and zonal Peak Demand (Table 2-1, Table 2-2, Table 2-3, and Table 2-4).

Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

The load development process is composed of several steps outlined in this section and will continue to be refined as needed in order to better capture weather uncertainty associated with the most recent load forecasts submitted by the Load Serving Entities.

The first step of the load development process includes data collection of the most recent year of historical hourly load data and the most recent historical temperature data from a zonal-specific weather station. This data is then consolidated with prior load and temperature data for a total historical dataset comprised of 30 years of hourly weather data and five years of hourly load data. For the PY 2025-2026 LOLE study, five years of historical data (2019 - 2023) was used in the neural net training/prediction portion of the load development process.

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Data Sources:

- Historical load data is collected from MISO Resource Assessment in compliance with NERC standard MOD-032-2 requirements.
- Weather data is collected through the National Oceanic and Atmospheric Administration (NOAA) and collected from the following weather stations for each zone.

LRZ	Station	Name	State	Latitude	Longitude	Elevation
1	72658014922	MINNEAPOLIS ST. PAUL INTERNATIONAL AIRPORT, MN US	Minnesota	44.89	-93.23	254.5
2	72640014839	MILWAUKEE MITCHELL AIRPORT, WI US	Wisconsin	42.95	-87.90	203.3
3	72546014933	DES MOINES INTERNATIONAL AIRPORT, IA US	Iowa	41.53	-93.65	286.3
4	72439093822	SPRINGFIELD ABRAHAM LINCOLN CAPITAL AIRPORT, IL US	Illinois	39.85	-89.68	176.7
5	72434013994	ST LOUIS LAMBERT INTERNATIONAL AIRPORT, MO US	Missouri	38.75	-90.37	162
6	72438093819	INDIANAPOLIS INTERNATIONAL AIRPORT, IN US	Indiana	39.73	-86.28	241.3
7	72539014836	LANSING CAPITAL CITY AIRPORT, MI US	Michigan	42.78	-84.60	261.2
8	72340313963	LITTLE ROCK AIRPORT ADAMS FIELD, AR US	Arkansas	34.73	-92.24	76.4
9	72231012916	NEW ORLEANS AIRPORT, LA US	Louisiana	30.00	-90.28	-1
10	72235003940	JACKSON INTERNATIONAL AIRPORT, MS US	Mississippi	32.32	-90.08	90.2

Table 3-7: Local Resource Zone Weather Stations

The second step of the process is to normalize the five years of load data to consistent economics. Each zone is analyzed and isolated to remove economic impacts on load to ensure that load levels at different temperatures provide an appropriate range across the most recent five years of historical data. This process involves zonal load growth adjustments by comparing the most recent five years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. A regression analysis is then performed at the zonal level, focusing on Summer, Winter, and off-peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. The NeuroShell Predictor software performs neural net training and predicting using a genetic algorithm. Since temperature data is not a direct input into the SERVM model, the relationships and effects it has on the MISO system are included in the 30-year hourly load shapes.

During the temperature and load training portion of this process, MISO evaluated each of the 10 LRZs by the following seasonal groupings: Summer, Winter, and off-season. Starting in the PY 2025-2026 LOLE study, the off-season grouping included both the Fall and Spring seasons. This was done to ensure there were enough extreme temperature data points and account for a larger sampling of temperature and load variability when the neural net predicts future load uncertainty. This process change resulted in an improved correlation between historical temperature and load data for the Fall and Spring seasons. The peak load and intra-hour load predictions drove some general load increases in these seasons during periods of extreme temperatures.

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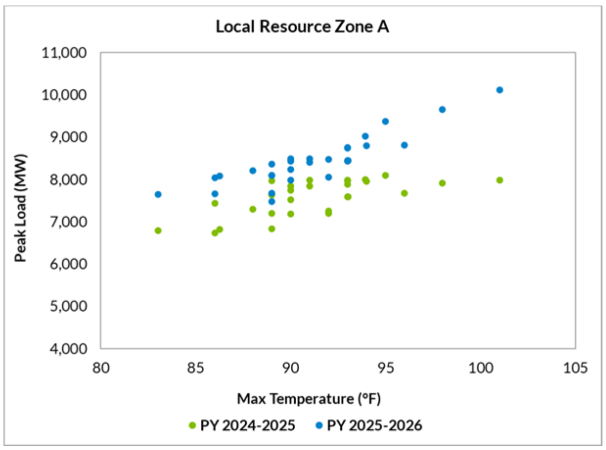
The graphs in Figure 3-6 below show how load responds to higher observed temperatures for months within the Fall and Spring seasons.

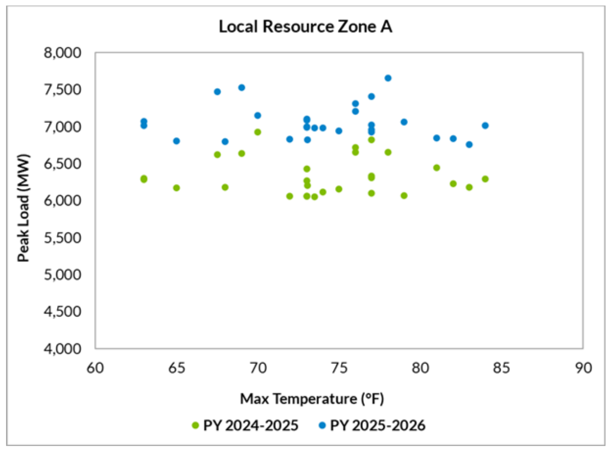
Comparable to off-season periods, the neural net software established functional relationships between historical temperature and load for the Summer and Winter seasons. However, unlike the off-season periods, the correlations between temperature and load for Summer and Winter seasons remained stable in the PY 2025-2026 LOLE study. When comparing the current Planning Year to the prior, no major outliers or concerns were identified in these correlations, and both years showed a general trend of increases in load at extreme temperatures.

The graphs in Figure 3-7 below show how load responds to higher observed temperatures for months within the Summer and Winter seasons.

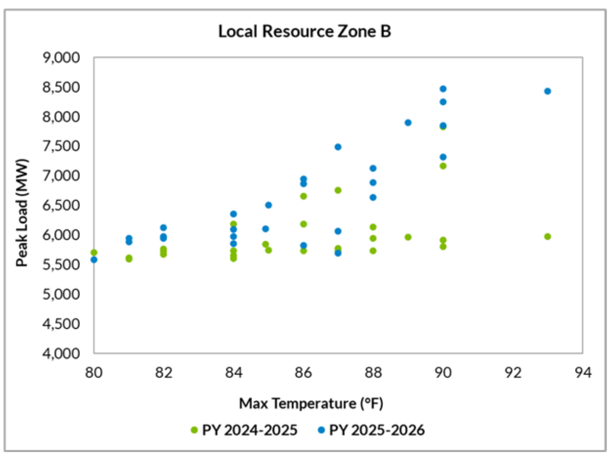
Fall Season
Temperature and Load Correlation
September



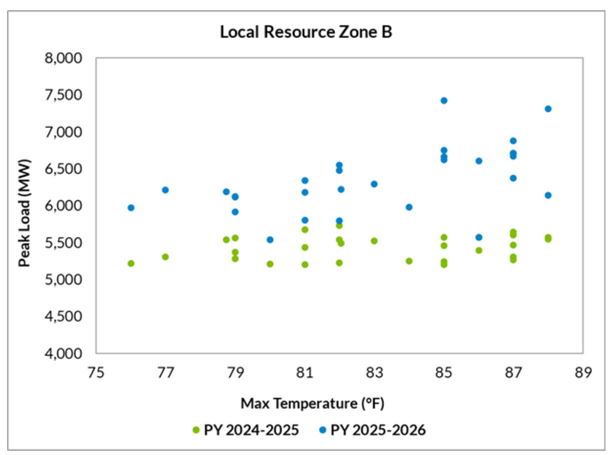
Spring Season
Temperature and Load Correlation
March



October



April



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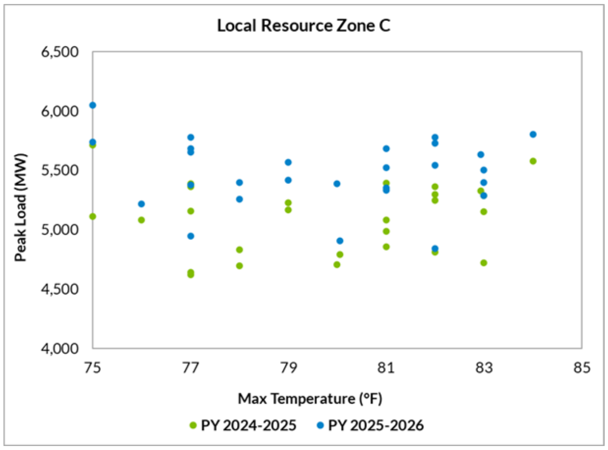
November



May

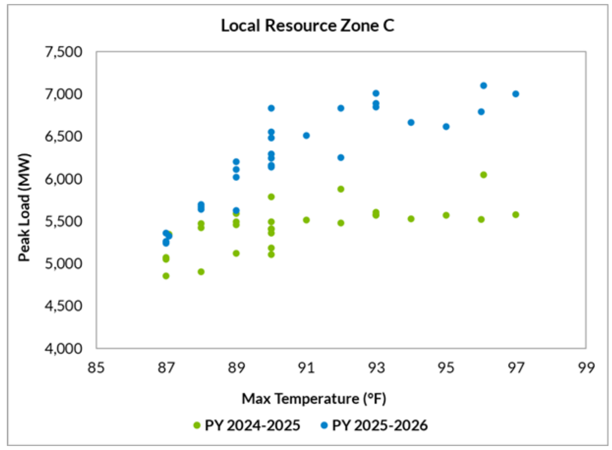
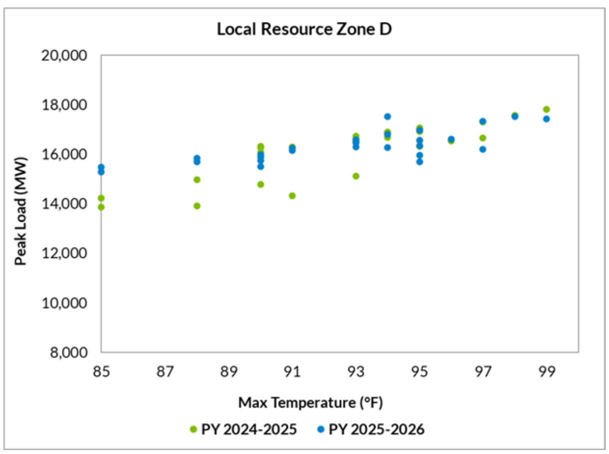
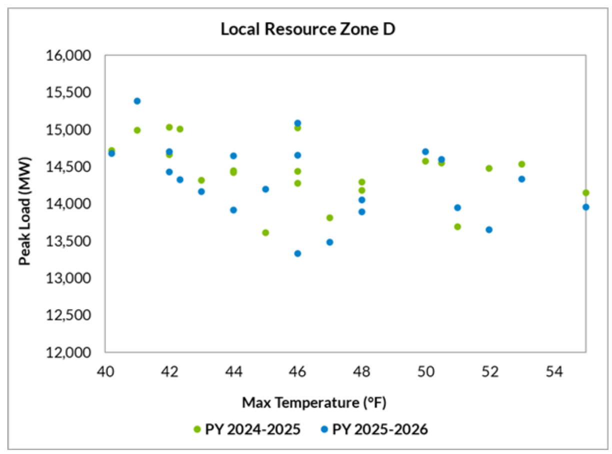


Figure 3-6: Temperature and Load Correlation for Fall and Spring Months

Summer Season
Temperature and Load Correlation
June



Winter Season
Temperature and Load Correlation
December



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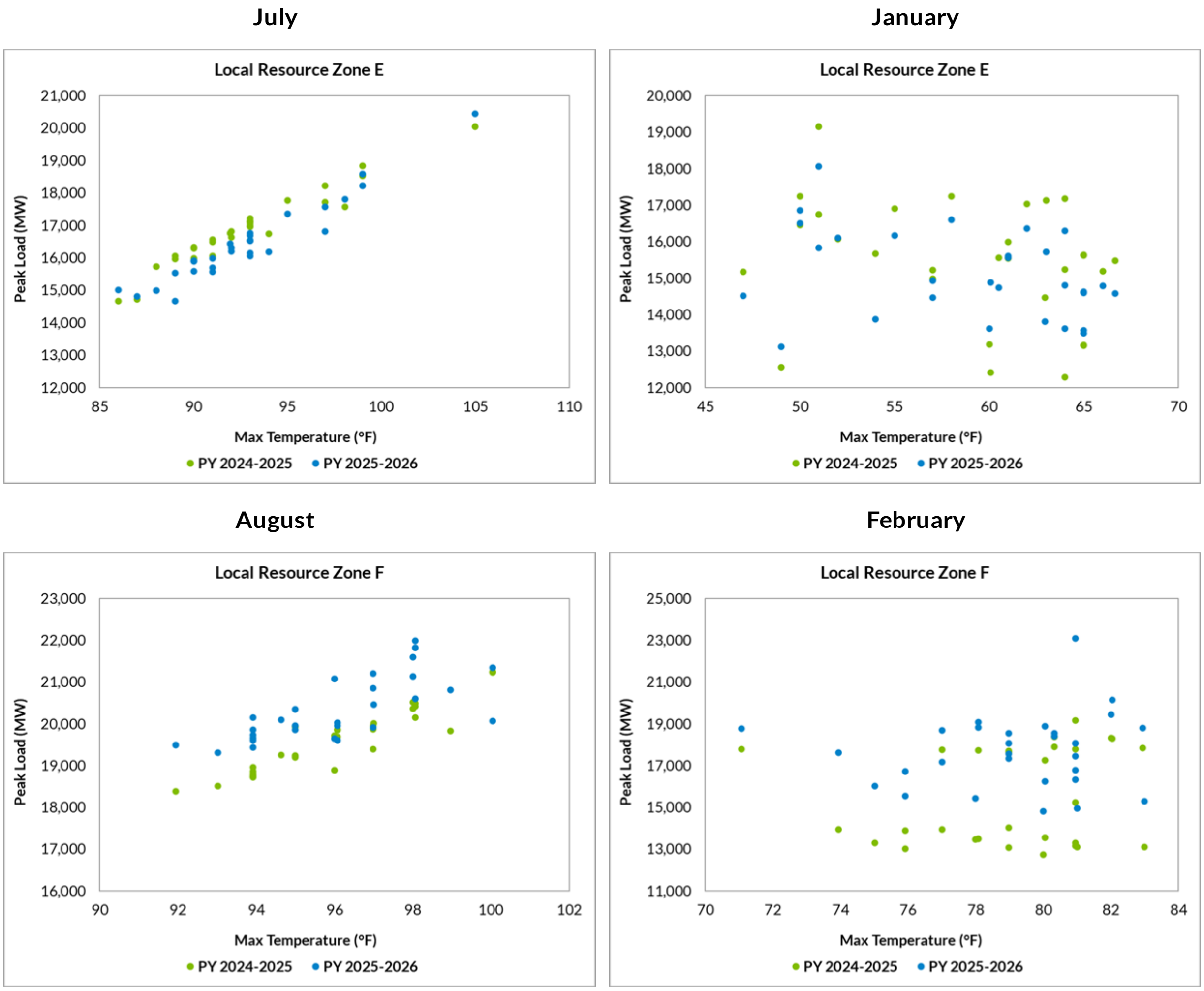

Figure 3-7: Temperature and Load Correlation for Summer and Winter Months

In the fourth step of the process and after the neural net has finished, MISO will validate the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing it against the entire 30 years of historical correlated load and weather data. During this step of the process, MISO will create a regression for the most extreme high and low temperatures in each zone to forecast out to temperatures in the 30-year range that the neural net may not have seen in the trained five-year historical load and temperature dataset.

In the fifth step of the load training process, MISO conducts a comparison of the synthetic 30-year hourly load shapes developed through the prior steps and the historical five years of hourly load data collected in the beginning of this process. During this comparative effort, MISO expects to see that the synthetic shapes are relatively in line with the historical shapes, but they should be slightly higher to account for any load reductions that were included in the historical net load shapes. If the resulting shapes are not in line with expectations, MISO will revisit step four and make any necessary changes in the regression during extreme temperatures. This may include reducing or increasing the number of data points to represent a more discrete trend.

The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ’s total monthly zonal Coincident Peak Demand forecast

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provided by the Load Serving Entities for each of the study years. To calculate the total monthly zonal Coincident Peak Demand forecasts for each year of study, the ratio of the monthly zonal Coincident Peak Demand forecast to the prompt seasonal Non-Coincident Peak Demand forecast is applied to the prompt and outyear seasonal Non-Coincident Peak Demand forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each zonal load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.4.1 Economic Load Uncertainty

To account for economic load uncertainty in the LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between historical projections and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-8.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.63%	0.9%	20.5%	57.3%	20.5%	0.9%

Table 3-8: Economic Uncertainty

3.5 External System

Firm imports from external areas to MISO are modeled at the individual resource level. Each firm external resource was modeled with its Installed Capacity amount and its corresponding seasonal forced outage rates, or at the contracted capacity from its corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analyses and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. External resources included as firm imports in the LOLE study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP), or that offered and subsequently cleared in the Planning Year 2024-2025 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-9 shows the number of firm import and export MW values in this year's study. Based on data from the Planning Year 2024-2025 PRA, MISO remained a net firm exporter.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,986	1,935	2,315	2,215	2,738	2,594	2,423	2,309
Exports (MW)	1,239	1,183	1,179	1,125	1,190	1,109	1,201	1,183
Net	**748**	**752**	**1,136**	**1,091**	**1,548**	**1,486**	**1,223**	**1,126**

Table 3-9: Planning Year 2025-2026 Firm Imports and Exports

Non-firm imports in the Planning Year 2025-2026 LOLE study were modeled as a seasonal probabilistic distribution representing three-year average energy imports, net of firm imports (already accounted for at the resource level), and off-system exports from MISO's internal generation. This modeling parameter is referred to as non-firm support. The distributions were developed using historic seasonal Net Scheduled Interchange (NSI) data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each season were subtracted from the NSI data to isolate the non-firm import values. An additional region was included in SERVM, which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model is provided in Table 3-10.

	Summer	Fall	Winter	Spring
p5	1,033	-71	-377	565
p10	1,371	561	-24	829
p25	2,413	1,485	642	1,736
p50	4,351	3,346	1,817	3,720
p75	6,073	5,111	4,242	5,383
p90	7,287	6,105	5,786	6,408
p95	7,657	6,436	6,380	6,710

Table 3-10: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.6 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal Planning Reserve Margin (PRM) values for Planning Year 2025-2026, as well as the seasonal Local Reliability Requirement (LRR) values for each of the 10 Local Resource Zones. The risk metrics were derived through

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probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.6.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that is used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1, then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter, while Fall and Spring had LOLE values of 0.00 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since Fall and Spring had 0.00 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01, and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met through further negative adjustments to capacity in these seasons.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2025-2026 LOLE study, is shown in Table 3-11. The MISO-wide seasonal LOLE distribution results from the PRM analyses, and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.10	0.01	0.01	0.01
LRZ 1	0.099	0.01	0.01	0.01
LRZ 2	0.091	0.01	0.01	0.01
LRZ 3	0.098	0.01	0.01	0.01
LRZ 4	0.01	0.01	0.10	0.01
LRZ 5	0.01	0.01	0.094	0.01
LRZ 6	0.091	0.01	0.01	0.01
LRZ 7	0.099	0.01	0.01	0.01
LRZ 8	0.01	0.01	0.093	0.01
LRZ 9	0.026	0.047	0.02	0.01
LRZ 10	0.069	0.015	0.01	0.012

Table 3-11: Planning Year 2025-2026 Seasonal LOLE Distribution

3.6.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE

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reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE study will calculate the seasonal PRM values based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFORd)

3.6.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analyses, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2025-2026 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates was added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates was added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criterion of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand) / Zonal Coincident Peak Demand

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4 Transfer Analysis

4.1 Calculation Methodology and Process Description

Transfer analyses determined Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values for LRZs in each season for Planning Year 2025-2026. Annual adjustments are made for Border External Resources and Coordinating Owner resources to determine the ZIA and ZEA in each season. Further adjustments are made for controllable exports, which are defined as exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. Controllable exports are subtracted from seasonal ZIA to determine seasonal CIL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Generation
    - Loss of baseload resources being replaced by renewable resources, which impacted generation dispatch, base flows, and transmission line loadings
    - +7 GW in net installed nameplate capacity
- Transmission
    - 700+ Transmission projects at $5B
    - Approximately 150 Transmission projects above 200 kV
- Demand
    - Approximately a 4% increase in all seasons

4.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem, and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem, and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

4.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as

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required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

4.1.3 Sensitivity

Transmission Owners in a specific zone can request that a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in a situation like that seen in Figure 4-1 below.

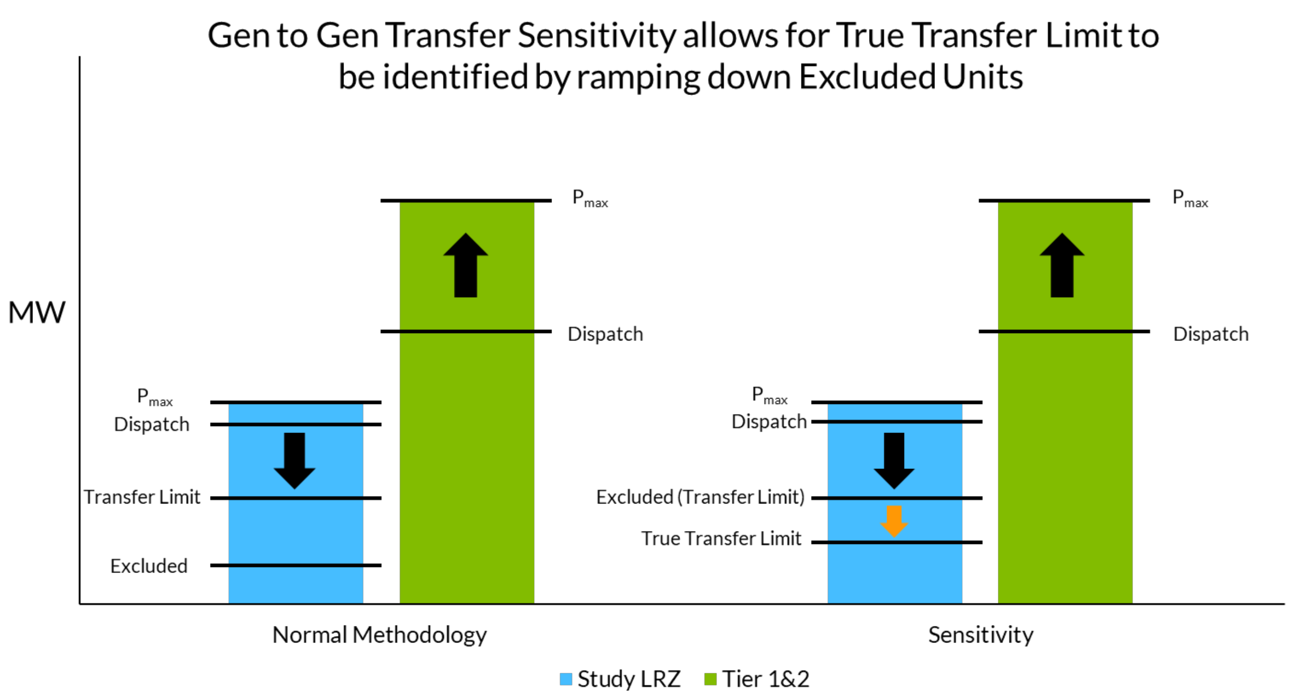

Figure 4-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology category would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity category identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation

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stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units, and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have these results included in their Capacity Import Limit for Planning Year 2025-2026.

4.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting a transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g., whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

4.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2025-2026, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2025-2026.

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4.2 Powerflow Models and Assumptions

4.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

4.2.2 Inputs Required

Thermal transfer analysis requires Powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which were used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix A for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

4.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 4-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2025	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2025	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Fall Peak	28.5%	31%
Winter 2025-2026	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2026	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Spring Peak	28.5%	31%

Table 4-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP24 analyses, with study files made available on MISO ShareFile. MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

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well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single-element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

4.2.4 General Assumptions

MISO uses TARA to process the Powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 4-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + \ FCITC$$

Equation 4-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of three percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by three percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 4-2 and Equation 4-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 4-2: Example Subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{Machine\ 1\ Reserve\ MW}{Source\ Subsystem\ Reserve\ MW} \times Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch$ = 25.8

Equation 4-2: Machine 1 Dispatch Calculation for 100 MW Transfer

4.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2025-2026 presented at the October 24th, 2024 meeting. Table 4-3 below shows the Planning Year 2025-2026 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\boldsymbol{ZIA = FCITC + Area\ Interchange - Border\ External\ Resources\ and\ Coordinating\ Owners}$$

Equation 4-3: Zonal Import Ability (ZIA) Calculation

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LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5573	5575
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370
LRZ 10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

Table 4-3: Planning Year 2025–2026 Import Limits

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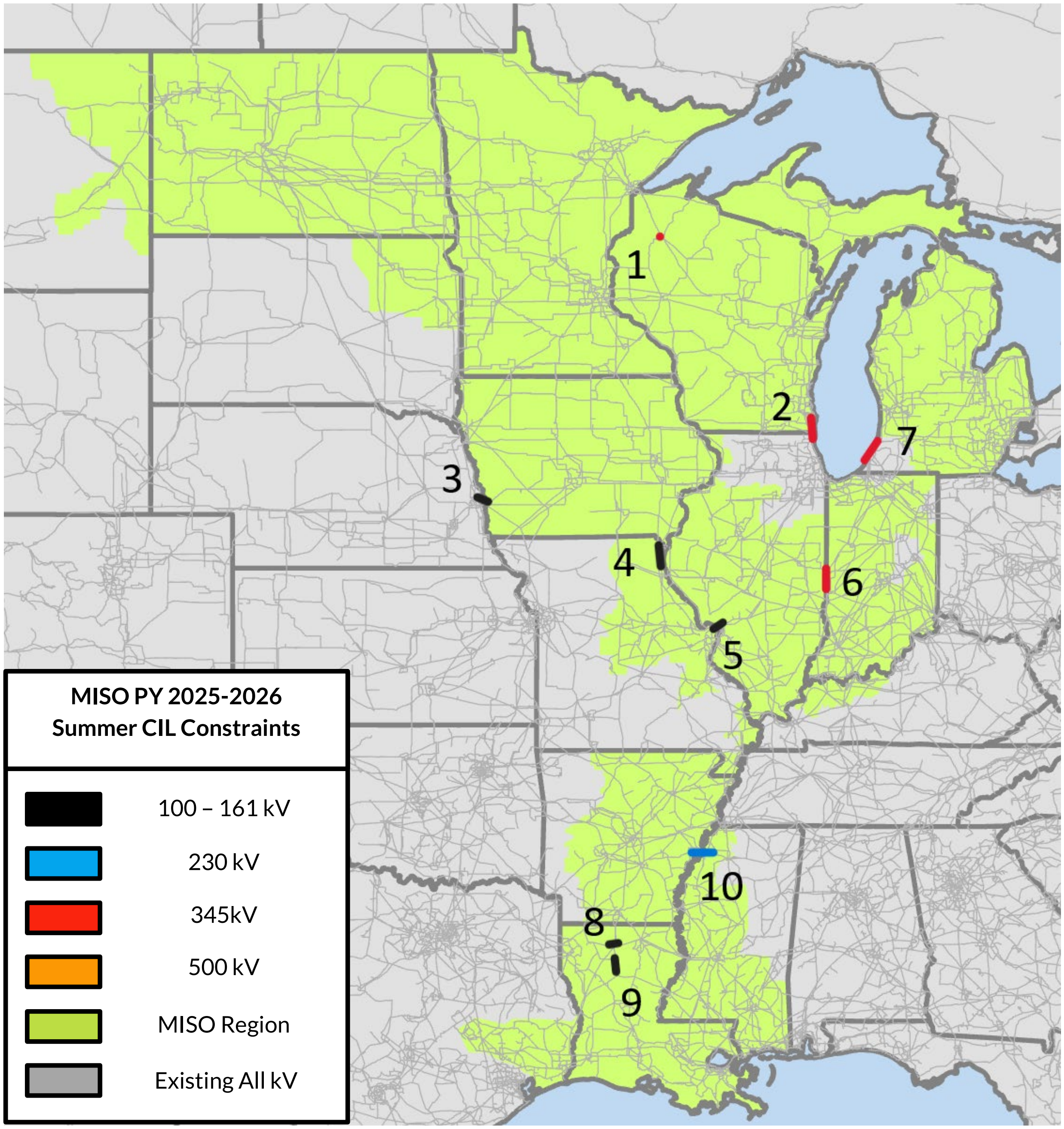

Figure 4-2: Planning Year 2025-2026 Summer Capacity Import Constraints Map

Schedule NLP-SR4

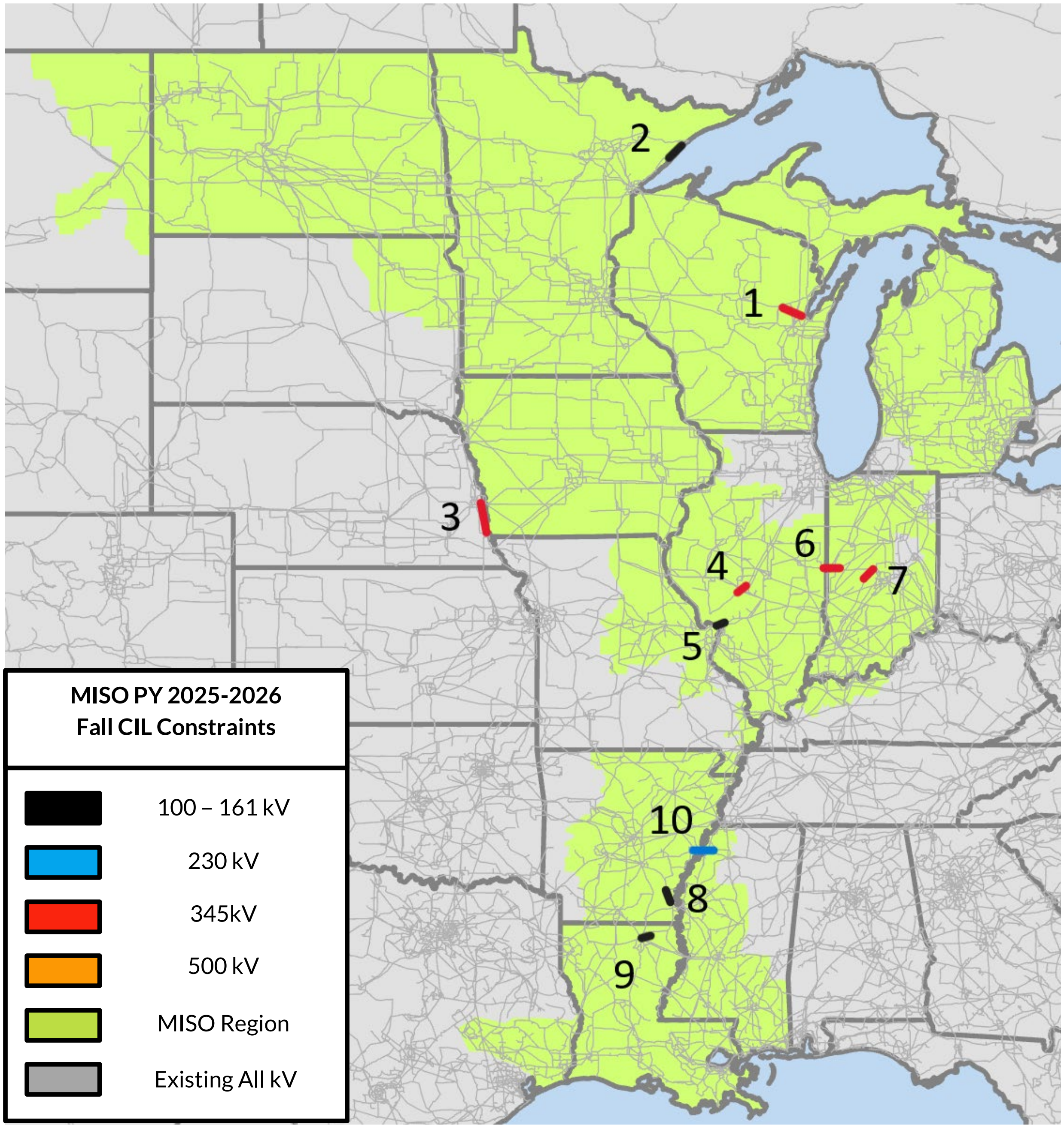

Figure 4-3: Planning Year 2025-2026 Fall Capacity Import Constraints Map

Schedule NLP-SR4

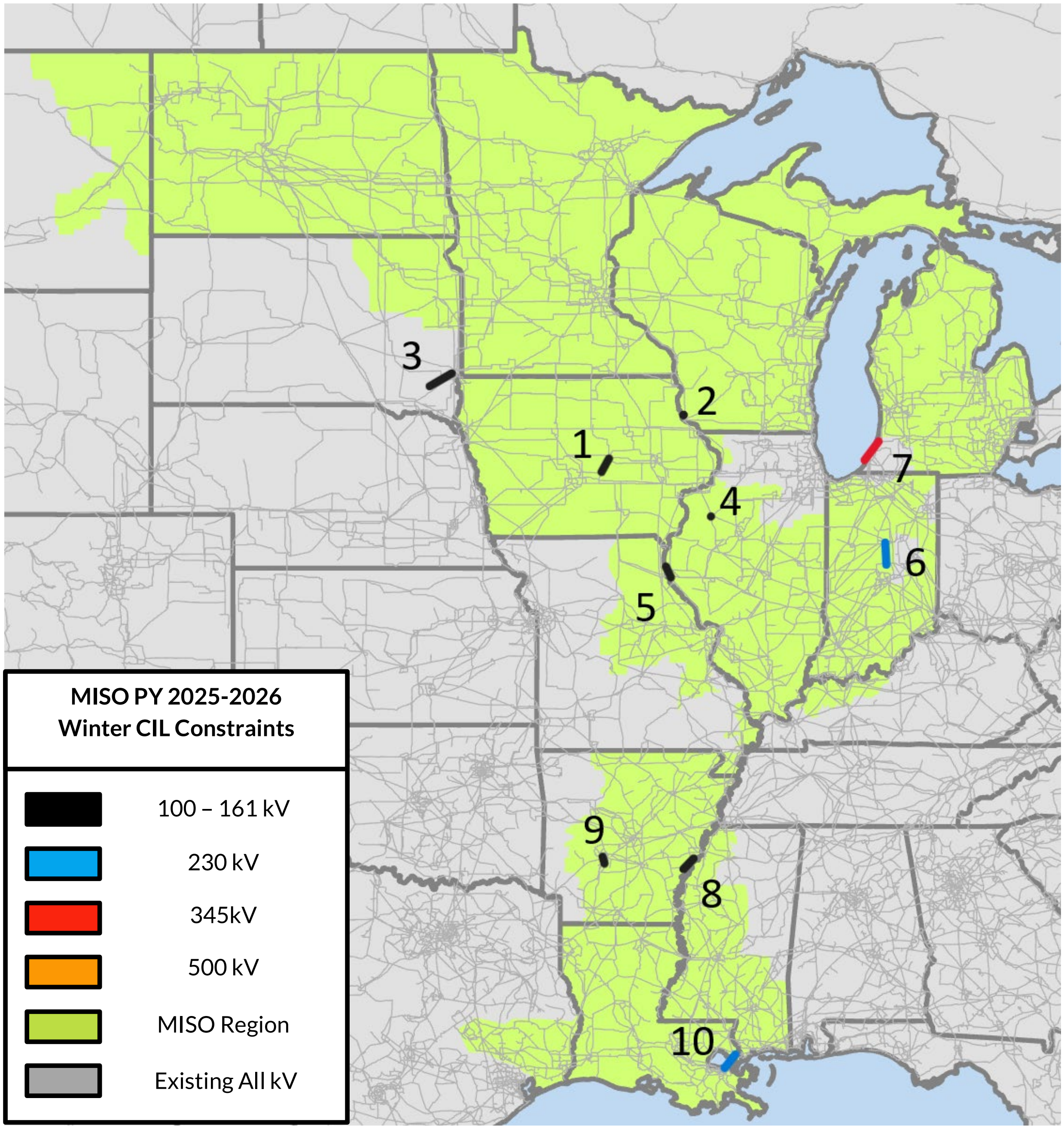

Figure 4-4: Planning Year 2025-2026 Winter Capacity Import Constraints Map

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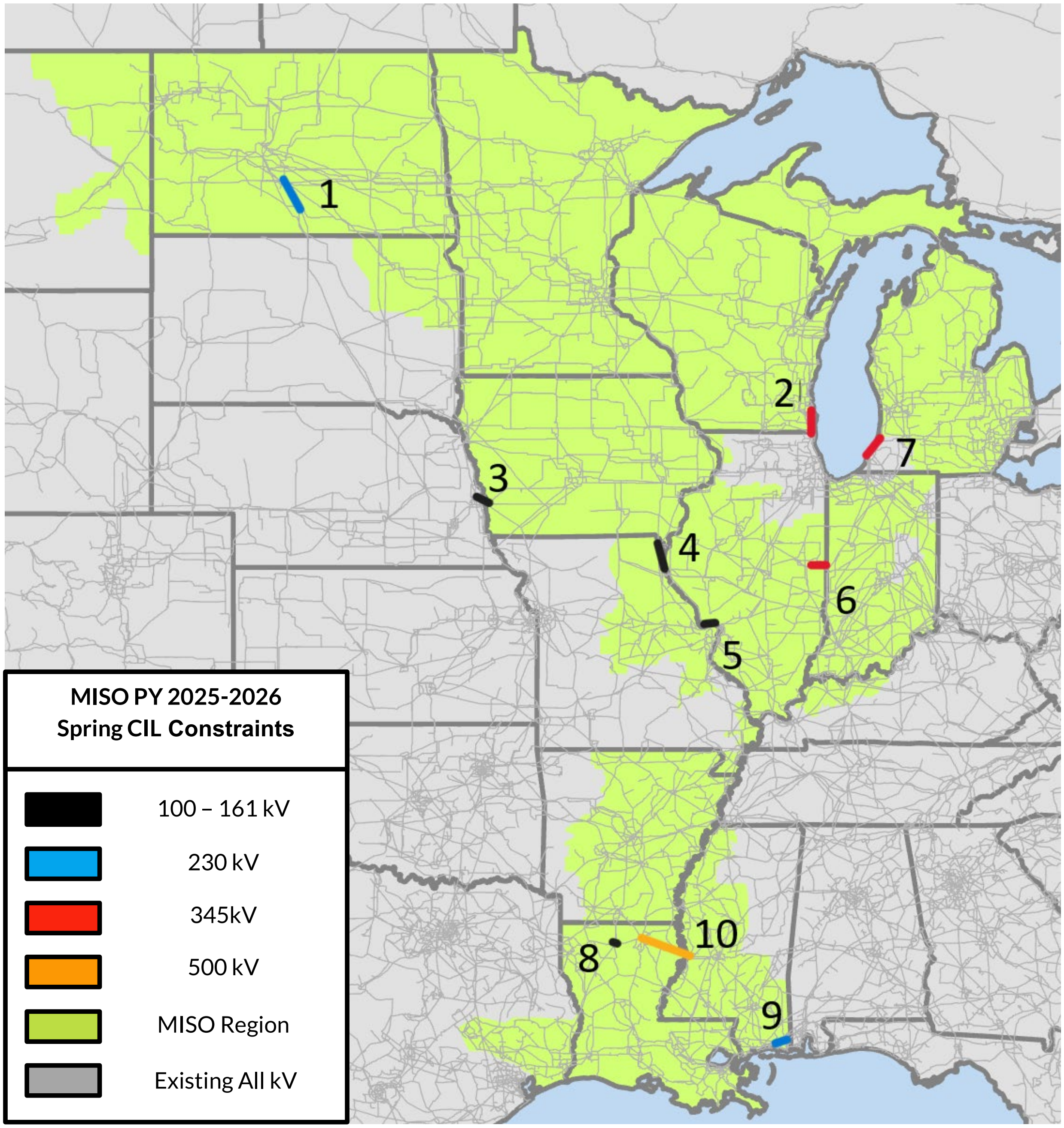

Figure 4-5: Planning Year 2025-2026 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 4-4 below shows the Planning Year 2025-2026 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072

Table 4-4: Planning Year 2025–2026 Export Limits

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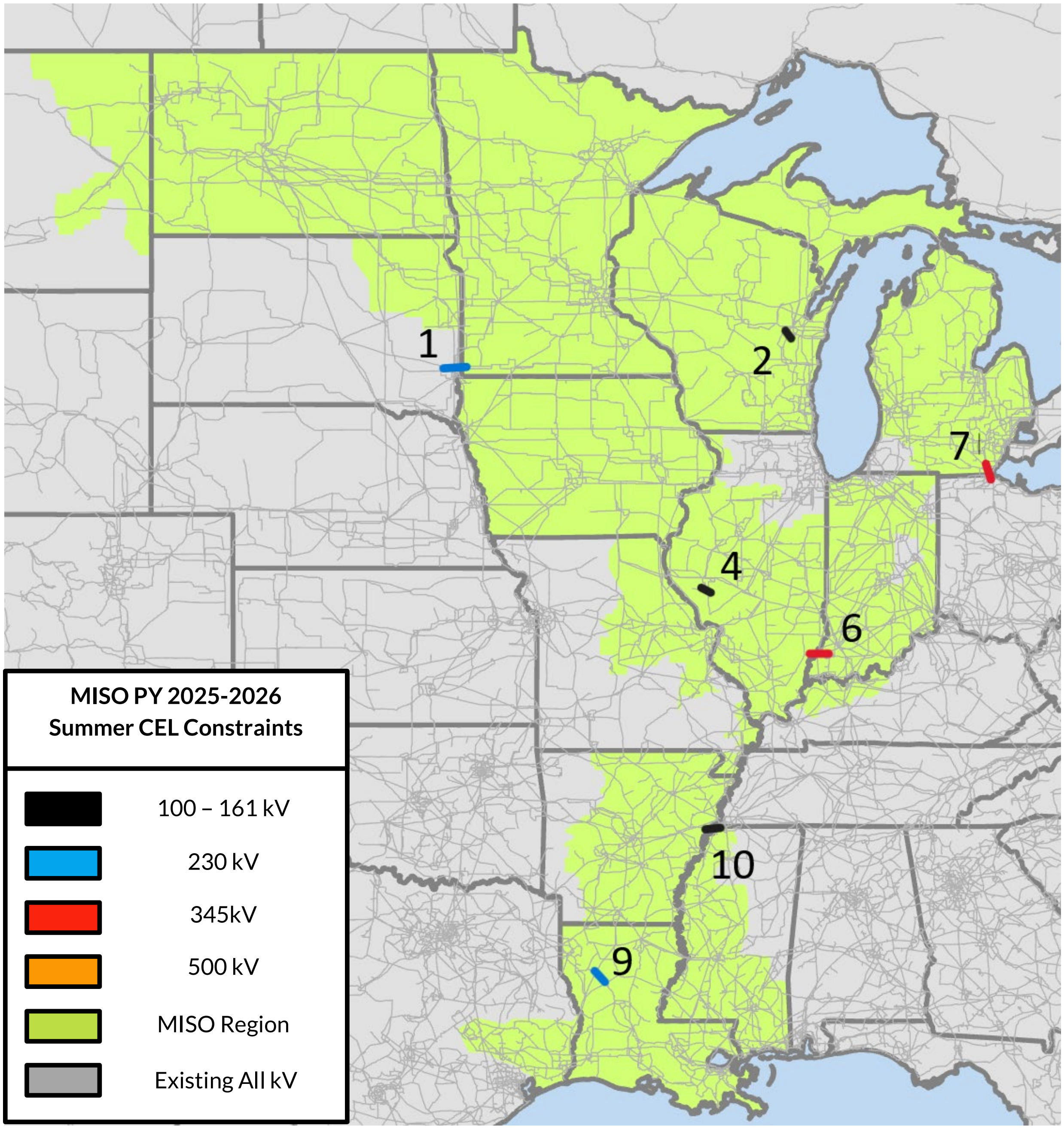

Figure 4-6: Planning Year 2025-2026 Summer Export Constraint Map

Schedule NLP-SR4

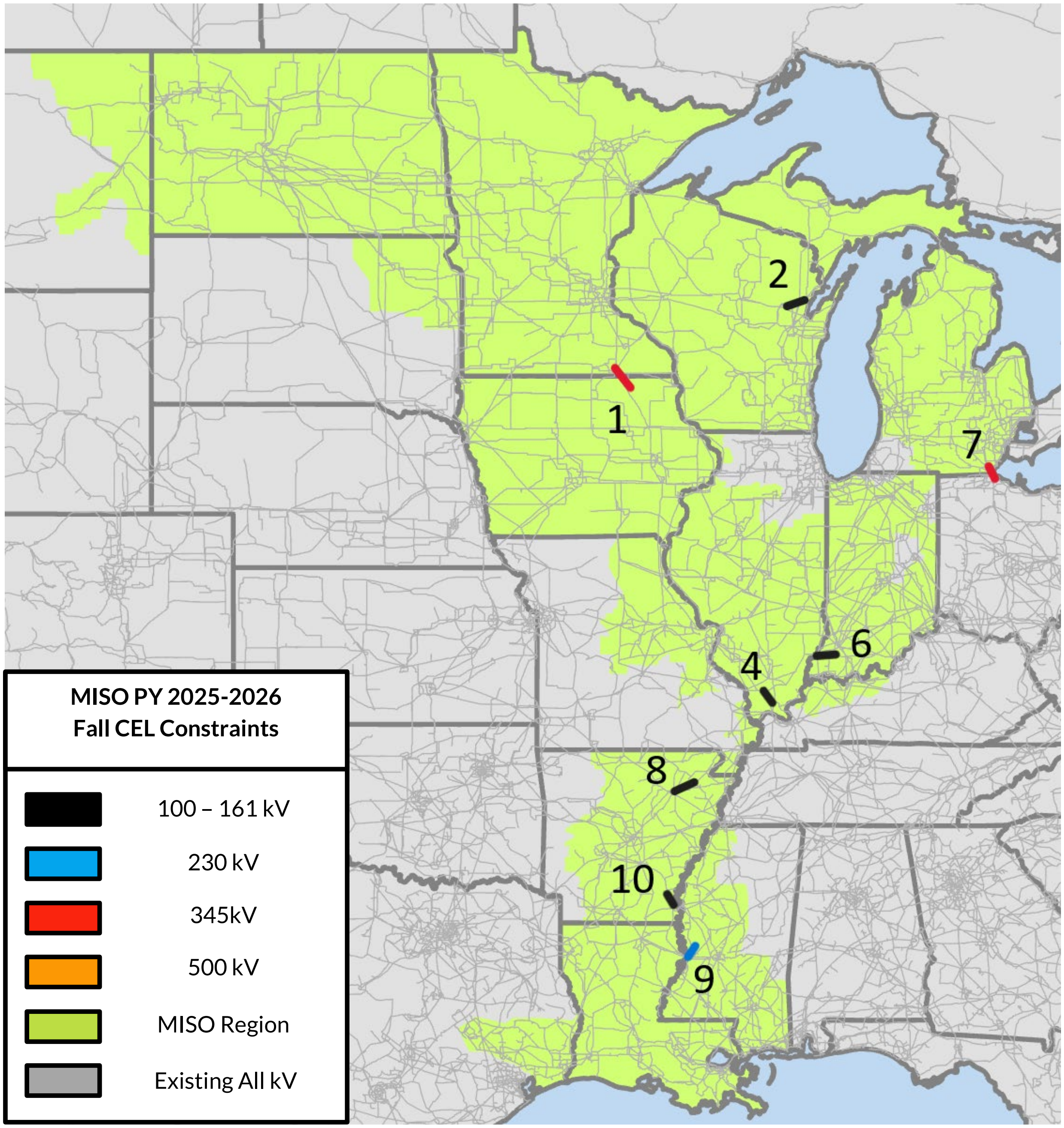

Figure 4-7: Planning Year 2025-2026 Fall Export Constraint Map

Schedule NLP-SR4

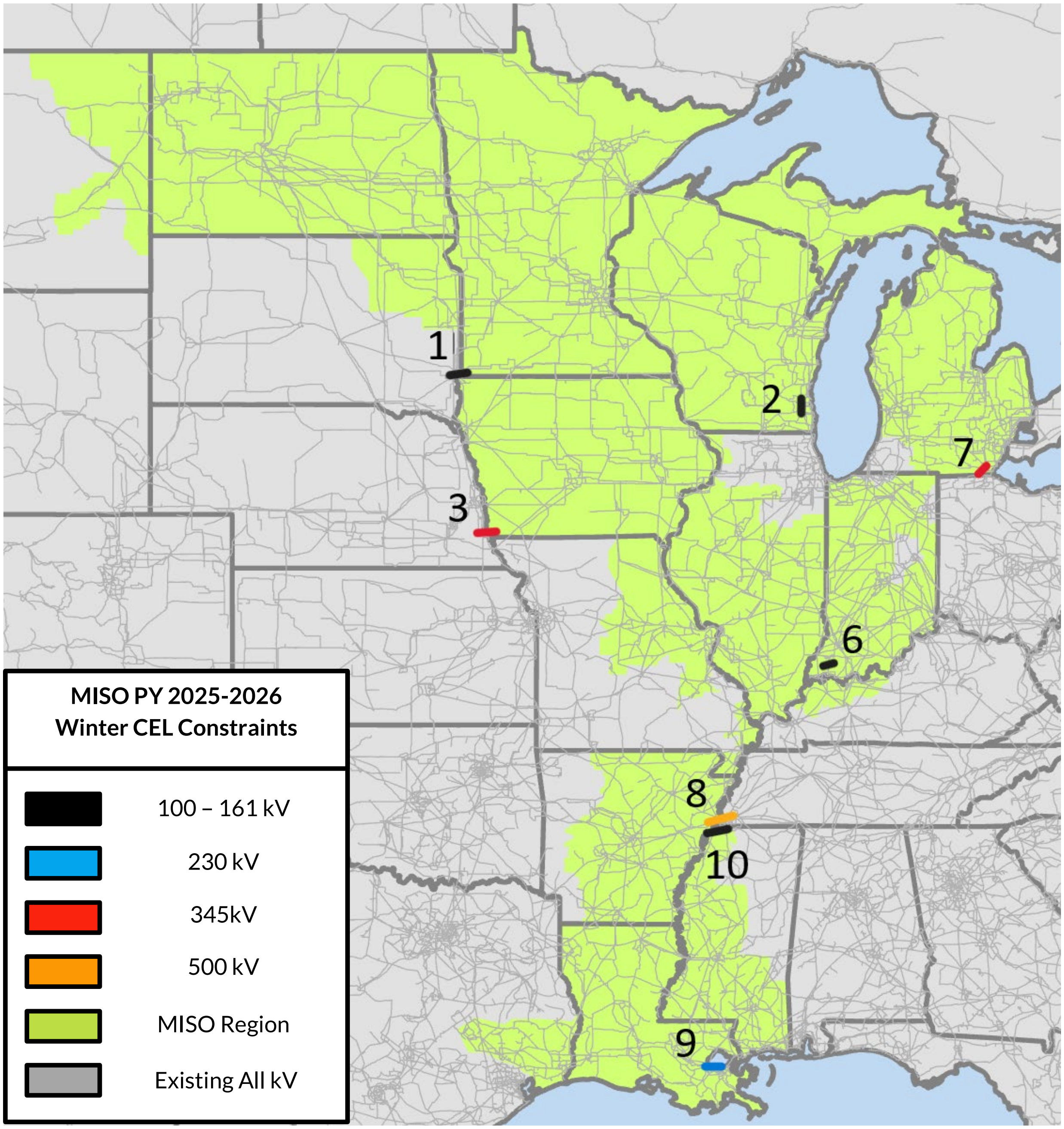

Figure 4-8: Planning Year 2025-2026 Winter Export Constraint Map

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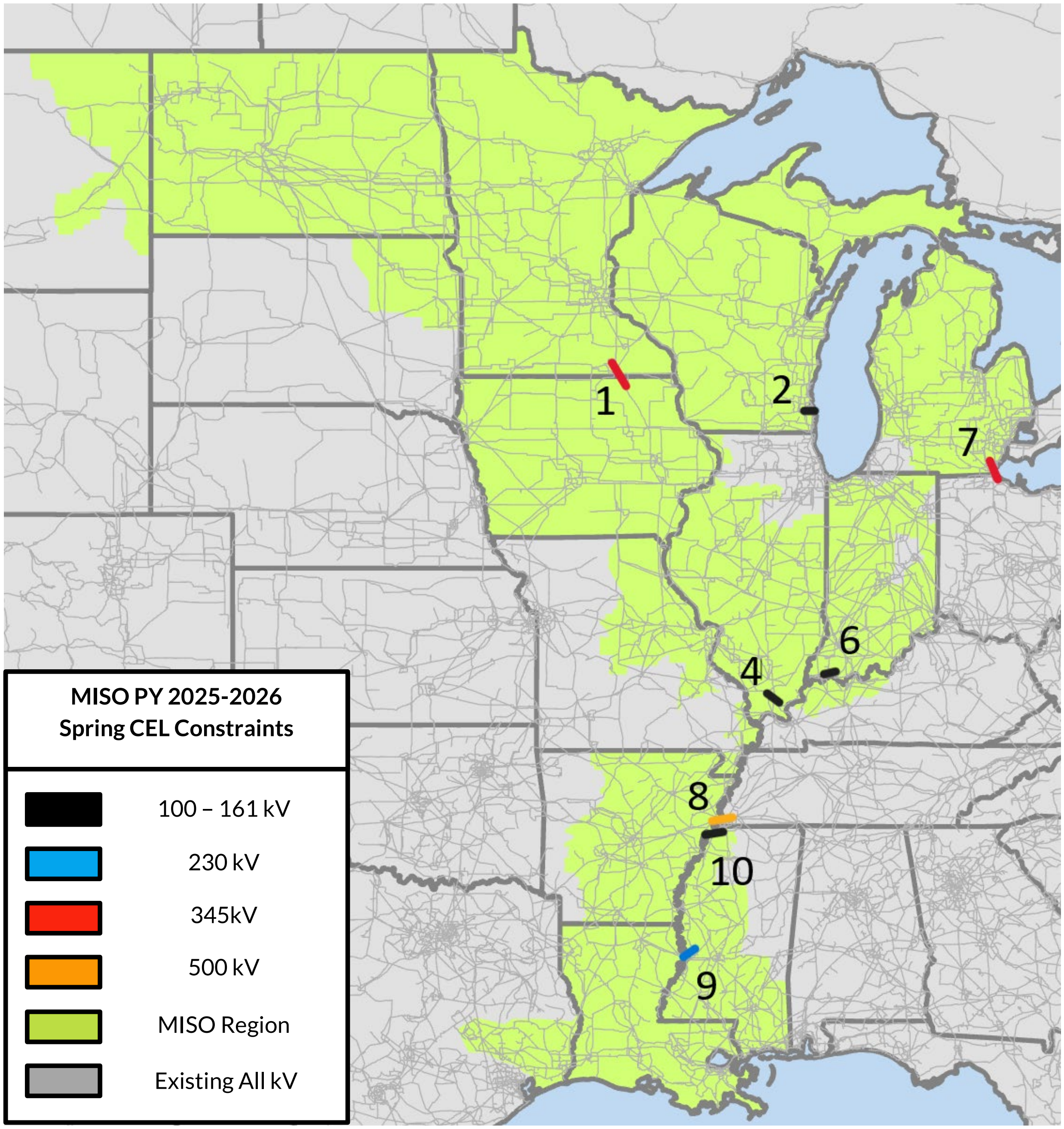

Figure 4-9: Planning Year 2025-2026 Spring Export Constraint Map

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Appendix A: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ALTW / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ALTW / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

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MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	HE / 207	GLHB / 362
MPW / 633	AMIL / 357	DEI / 208	MP / 608
MEC / 635	XEL / 600	NIPS / 217	GRE / 615
	SMMPA / 613	WEC / 295	OTP / 620
	DPC / 680	CWLP / 360	WPS / 696
	ALTE / 694	SIPC / 361	MGE / 697

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	HE / 207	SIGE / 210	DPC / 680
CWLP / 360	DEI / 208	IPL / 216	ALTE / 694
SIPC / 361	NIPS / 217	METC / 218	
GLHB / 362	BREC / 314	HMPL / 315	
GLH / 373	AMMO / 356	XEL / 600	
	ITCM / 627	SMMPA / 613	
	MEC / 635	MPW / 633	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	HE / 207	SMMPA / 613
AMMO / 356	GLHB / 362	DEI / 208	MPW / 633
	ALTW / 627	NIPS / 217	DPC / 680
	MEC / 635	CWLP / 360	ALTE / 694
		SIPC / 361	
		XEL / 600	

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MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ALTW / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	SMEPA / 349
		CLEC / 502
		LAFA / 503

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MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	SMEPA / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
SMEPA / 349	EES / 351	CLEC / 502
		LAFA / 503

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Appendix B: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2025-2026 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2025 through May 2026 and beyond. Analysis of Planning Year 2025-2026 is in Sections 1.2 and 2.1. Analysis of Future Years 2025-2034 will be included in Appendix D as an addendum to the study report and published in Q1 of 2025.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.6 of this report outlines the utilization of LOLE in the reserve margin determination. "The risk metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.4 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 1.2 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 1.2 and 2.1, a full analysis was performed for Planning Year 2025-2026.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10-year period.	Analysis of Planning Years 2028-2029 and 2030-2031 will be included in Appendix D as an addendum to the study report in Q1 2025.

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Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load Forecast Uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load Diversity • Seasonal Load Variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.4 of this report: “The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ’s total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each of the study years.” Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.4. Load Diversity / Seasonal Load Variations — In Section 3.4 of this report: “Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent 5 years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability.” Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: “Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season.”

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Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.5.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves.	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 4 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis.	Inclusion of the planned transmission addition assumptions is detailed in Section 4.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.5 provides the analysis on the treatment of external support assistance and limitations.

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Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.6.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 4 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.	MISO internal resources are among the quantities documented in the tables provided in Sections 1 and 2.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.	MISO load is among the quantities documented in the tables provided in Sections 1 and 2.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 1 and 2, the peak load and estimated amount of resources for Planning Year 2025-2026 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix D will detail the future Planning Year analysis and will be updated in Q1 of 2025.

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Requirements under: Standard BAL-502-RF-03	**Response**
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Section 1.2. The outyear Planning Years 4 (2028-2029) and 6 (2030-2031) will be covered in Appendix D and be published in Q1 2025.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2025-2026 LOLE Study Report will be posted publicly in November 2024, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 1 and 2 show the differences between the needed amount and the projected planning reserves for Planning Year 2025-2026. The amount of planning reserves needed for the outyear Planning Years 4 (2028-2029) and 6 (2030-2031) will be covered in Appendix D in Q1 2025.

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Appendix C: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

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PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SAC	Seasonal Accredited Capacity
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

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Appendix D: Outyear PRM Results

Outyear Planning Reserve Margin results for the future Plannings Years 2028-2029 and 2030-2031 will be published as an addendum to this report in Q1 of 2025 once the supporting probabilistic simulations and analyses have been completed.

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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust Its Revenues for Electric Service.	)))	Case No. ER-2024-0319

AFFIDAVIT OF NICHOLAS L. PHILLIPS

STATE OF MISSOURI)
) **ss**
CITY OF ST. LOUIS)

Nicholas L. Phillips, being first duly sworn states:

My name is Nicholas L. Phillips, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Surrebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

Nicholas L. Phillips

Sworn to me this 4 day of February, 2025.