SOAH DOCKET NO. 473-25-09020
PUC DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND ATTACHMENTS

OF

KARL J. NALEPA

ON BEHALF OF

ALLIANCE OF XCEL MUNICIPALITIES

FEBRUARY 28, 2025

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TABLE OF CONTENTS

Page

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND ADDRESS.

A. My name is Karl J. Nalepa. I am a partner in, and President of ReSolved Energy Consulting, LLC (REC), an independent utility consulting company. My business address is P.O. Box 90908, Austin, Texas 78709.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I hold a Master of Science degree in Petroleum Engineering from the University of Houston and a Bachelor of Science degree in Mineral Economics from Pennsylvania State University. I am also a certified mediator.

I have been a partner in REC since July 2011, but joined R.J. Covington Consulting, its predecessor firm, in June 2003. I lead our firm's regulated market practice, where I represent the interests of clients in utility regulatory proceedings, prepare client cost studies, and develop client regulatory filings. Before joining REC, I served for more than five years as an Assistant Director with the Railroad Commission of Texas (RRC). In this position, I was responsible for overseeing the economic regulation of natural gas utilities in Texas, which included supervising staff casework, advising Commissioners on regulatory issues, and serving as a Technical Rate Examiner in regulatory proceedings. Prior to joining the RRC, I worked as an independent consultant advising clients on a broad range of electric and natural gas industry issues, and before that, I spent five years as a supervising consultant with Resource Management International, Inc. I also served for four years as a Fuels Analyst with the Public Utility Commission of Texas (PUC or Commission), where I evaluated fuel issues in electric utility rate filings and fuel reconciliation filings, participated in electric utility-related rulemaking proceedings, and took part in the review of electric utility resource plans. My professional career began with eight years in the reservoir engineering department of Transco Exploration Company, which was an affiliate of Transco Gas Pipeline Company, a major interstate pipeline company. My Statement of Qualifications is included as Attachment KJN-1.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN A COMMISSION PROCEEDING?

A. Yes, I have testified many times before both the Commission and the RRC on a variety of regulatory issues. I have also provided testimony before the Louisiana Public Service Commission, Arkansas Public Service Commission, and Colorado Public Utilities Commission. A summary of my previously filed testimony is included as Attachment KJN-2. In addition, I have provided analysis and recommendations in many city-level regulatory proceedings that resulted in decisions without written testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am offering testimony on behalf of the Alliance of Xcel Municipalities (AXM).

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to evaluate whether the Southwestern Public Service Company (SPS or Company) System Resiliency Plan (Resiliency Plan, Plan, or SRP) complies with the governing statutory and regulatory requirements and recommend conforming adjustments if necessary.

Q. WHAT IS AXM'S POSITION REGARDING ENHANCEMENTS TO SYSTEM RESILIENCY?

A. AXM supports efforts that provide ratepayers with a more resilient and hardened system so that outages are mitigated, or avoided all together, during extreme weather events. AXM is a coalition of cities in a service territory that are directly impacted by outages and system failures caused by extreme weather and other resiliency events. Therefore, the importance of enhancing the resiliency of a utility's system is not lost on the cities that comprise this coalition.

Moreover, AXM recognizes that efforts to make SPS's system more resilient and hardened will require substantial capital investment on the part of the Company. Crucially, however, if found prudent by the Commission, ratepayers will be paying for SPS's capital investment to implement the Resiliency Plan via a return of and on this investment.

Consequently, in exchange for the concomitant effect that SPS's Resiliency Plan will have on customers' rates, it is imperative that the investments made by any utility to enhance the resiliency of its system go towards the measures that are the most effective and beneficial to ratepayers, and not towards measures that are not effective and/or beneficial to ratepayers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. After review and evaluation of SPS's proposed Resiliency Plan, I make the following findings and recommendations:

1. The projected cost of $538.3 million to implement the Company's Plan is substantial given the number of customers it serves. SPS estimates that the first-year revenue requirement impact of its Plan will increase residential customer bills by a significant $10.94 per month. Ratepayers should not be expected to pay more than is necessary to implement the Resiliency Plan.

2. Behind TNMP, SPS has the second-highest average SRP cost per customer of all utilities with SRP filings. Although resiliency programs are utility-specific and in particular SPS claims it has a low customer density which can drive up the cost per customer, the statute provides detailed parameters for allowed programs so implementation costs should fall within a reasonably narrow range. The high cost per customer invites a closer look into SPS's proposed measures.

3. The costs under the Company's Distribution Overhead Hardening measure accounts for nearly half of SPS's total request. Thus, the costs under this measure should be reduced to provide some relief to customers. I recommend that Distribution Overhead Hardening costs for activities within the Tier 1 (low) wildfire risk area be removed. This amount is $17.8 million and removing these costs will not affect SPS's wildfire mitigation goal.

4. To avoid the overlap of programs and duplication of costs, I recommend that SPS separately track the Distribution Overhead Hardening measure costs under 1) its existing programs, and 2) the hardening measures proposed in its Plan. The Company

should report these separate activities at a time and in a format specified by the Commission. If the report demonstrates that overlap has occurred, this provides the Commission with the information necessary to adjust SPS's costs and/or rates in a future proceeding.

5. It is not reasonable to include projects with a BCR of less than 1.0 in the SRP, especially since SPS is unable to verify that its "qualitative" benefits make up the difference. I recommend that investment for projects with a BCR< 1.0, be removed. This amount is $3.9 million.

6. As with the Distribution Overhead Hardening measure, to avoid the overlap of programs and duplication of costs, I recommend that SPS separately track the Distribution System Protection Modernization measure costs under 1) its existing programs, and 2) the measures proposed in its Plan. The Company should report these separate activities at a time and in a format specified by the Commission. If the report demonstrates that overlap has occurred, this provides the Commission with the information necessary to adjust SPS's costs and/or rates in a future proceeding.

7. SPS functionalizes the $112.7 million in Communication Modernization capital investment between Transmission plant ($16.6 million) and General plant ($96.1 million). Unless SPS can provide a supportable basis to allocate any of this capital investment to Distribution, I recommend these costs should not be included in the Distribution regulatory asset.

8. I recommend that the 6 additional mobile substations requested by SPS in its Operational Flexibility measure be rejected, as SPS has not shown them to be necessary or provide any additional resiliency benefit. The capital cost of the mobile substations is $30.8 million. If the Commission determines to approve procurement of the additional mobile substations, then I recommend only the amounts functionalized to Distribution be included in the regulatory asset.

9. SPS's wildfire mitigation measure is reasonable and should be approved. The measure envisions a broad range of programs to mitigate the impact of wildfires and complements SPS's current vegetation management budget of only $2.1 million. O&M expense is allocated to Transmission ($3.3 million) and Distribution ($13.5 million) and this allocation should be reflected in the regulatory asset.

10. Tracking SAIDI is an important metric, but a rolling 10-year average dilutes the impact on SAIDI. SAIDI should be tracked no longer than on a rolling 3-year average. In addition, SPS should also measure a rolling 3-year average SAIFI. Both the frequency and duration of outages provide important information on SPS's ability to improve system resiliency.

11. The Public Utilities Commission of Colorado approved several metrics for Public Service Company of Colorado that should be considered by the Commission in SPS's proposed SRP. These metrics include:

- The number of ignitions associated with electric overhead power lines within each wildfire risk Tier;
- The number of downed transmission and distribution wires within each wildfire risk Tier;
- The total number of wildfires in the Company's service territory;
- Percentage of on-cycle vegetation management activities for transmission and distribution assets in each wildfire risk Tier.

III. RESILIENCY PLAN BACKGROUND

Q. WHAT IS THE BASIS FOR SPS'S RESILIENCY PLAN?

A. In 2023, the 88th Texas Legislature passed, and the Governor signed into law H.B. 2555,[1] which created Public Utility Regulatory Act (PURA) § 38.078 and permits an electric utility to request Commission approval of the electric utility's transmission and distribution system resiliency plan. In passing H.B. 2555, the 88th Legislature made the following findings:

- protecting electrical transmission and distribution infrastructure from weather conditions can effectively reduce system restoration costs to and outage times for customers and improve system resiliency and overall service reliability for customers;
- it is in the state's interest for each electric utility to seek to mitigate system restoration costs to and outage times for customers when developing plans to enhance electrical transmission and distribution infrastructure storm resiliency; and
- all customers benefit from reduced system restoration costs.[2]

SPS's Resiliency Plan was developed in response to HB 2555 and PURA § 38.078.[3]

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[1] H.B. 2555, 88th Leg., R.S. (2023).

[2] *Id.*, Section 1, Subsections (3)-(5).

[3] *Application of Southwestern Public Service Company for Approval of its Transmission and Distribution System Resiliency Plan* at 2 (Dec. 30, 2024) (Application).

Q. WHAT MUST BE INCLUDED IN A RESILIENCY PLAN?

A. PURA § 38.078 allows an electric utility to file for approval by the Commission a plan to enhance the resiliency of its transmission and distribution system through a list of measures described in the Section.[4] The plan must explain the systematic approach the utility will use to carry out the plan during at least a three-year period[5] and the Commission must consider the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance and the estimated costs of implementing the measures proposed in the plan, in determining whether to approve the plan.[6] The Commission may approve a plan only if it determines that the plan is in the public interest.[7] Furthermore, an electric utility for which the Commission has approved a plan may request that the Commission review an updated plan no earlier than three years after approval of the most recent plan.[8]

Q. HOW IS THE IMPLEMENTATION OF AN APPROVED PLAN REVIEWED?

A. The implementation of an electric utility's approved plan may be reviewed under the rate provisions of PURA Chapter 36 or Chapter 38. If the Commission determines that the costs to implement an approved plan were imprudently incurred or otherwise unreasonable, those costs are subject to disallowance.[9]

Q. HOW ARE IMPLEMENTATION COSTS RECOVERED FROM A UTILITY'S CUSTOMERS?

A. Under PURA § 38.078, an electric utility may file with its resiliency plan an application for a rider to recover its distribution investment that is made to implement a plan and is used and useful in providing service to the public. The utility may file the application for a rider and the Commission may approve the rider before the utility places the distribution investment into service. However, the rider may not allow the utility to begin recovering

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4 Public Utility Regulatory Act (PURA) § 38.078(b).

5 PURA § 38.078(c).

6 PURA § 38.078(d).

7 PURA § 38.078(e).

8 PURA § 38.078(g).

9 PURA § 38.078(h).

the distribution investment before it is used and useful in providing service to the public.[10] The Commission shall also adopt a procedure for reconciliation of an electric utility's distribution-related costs to implement an approved plan to determine the electric utility's reasonably and prudently incurred plan costs.[11]

If an electric utility that files a plan with the Commission does not apply for a rider, the utility may defer all or a portion of the distribution-related costs relating to the implementation of the plan for future recovery as a regulatory asset, including depreciation expense and carrying costs at the utility's approved weighted average cost of capital (WACC). The regulatory asset may be recovered through a Transmission Cost Recovery Factor (TCRF) for utilities operating solely outside of ERCOT, Distribution Cost Recovery Factor (DCRF), or another general rate proceeding.[12]

Q. IS THERE A RESTRICTION ON THE COSTS TO BE RECOVERED?

A. Yes. Plan costs considered by the Commission to be reasonable and prudent may include only incremental costs that are not already being recovered through the electric utility's base rates or any other rate rider and must be allocated to customer classes pursuant to the rate design most recently approved by the Commission.[13]

Q. HAS THE COMMISSION ADOPTED A RULE IMPLEMENTING PURA § 38.078?

A. Yes. 16 Tex. Admin. Code (TAC) § 25.62, *Transmission and Distribution System Resiliency Plans*, implements PURA§ 38.078.

IV. OVERVIEW OF THE APPLICATION

Q. WHAT IS SPS REQUESTING IN ITS APPLICATION?

A. SPS is requesting the Commission:[14]

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10 PURA § 38.078(i).

11 PURA § 38.078(j).

12 PURA § 38.078(k).

13 PURA § 38.078(l).

14 Application at 17.

- find SPS's proposed SRP is in the public interest and compliant with 16 TAC § 25.62, and approve it;
- authorize SPS to implement the SRP through 2028 or at least three years after any approval of this SRP, whichever is later, unless SPS requests to amend the SRP with the amendment to take effect no later than three years from an approval of this SRP;
- approve SPS's requested flexibility in implementation as described in the SRP;
- authorize SPS to establish a regulatory asset to capture distribution-related costs related to the implementation of the SRP;
- authorize a twelve-month amortization period for the regulatory asset as requested above;
- authorize SPS to defer all costs associated with the preparation and defense of this application;
- approve SPS's proposed metrics as stated in the SRP; and
- grant all other relief the Commission deems necessary or appropriate.

Q. WHAT RESILIENCY MEASURES ARE INCLUDED IN SPS'S PLAN?

A. SPS includes five measures in its Plan. Table 1 below identifies the measures and the associated costs:[15]

Table 1

Resiliency Measure	Estimated Capital Costs (millions)	Estimated O&M Expense (millions)
Distribution Overhead Hardening	$253.0	$0.0
Distribution System Protection Modernization	$92.3	$0.0
Communication Modernization	$112.7	$0.0
Operational Flexibility	$43.7	$0.006
Wildfire Mitigation	$19.8	$16.8
Total	$521.5	$16.8
Grand Total		$538.3

The total estimated capital costs and O&M expense is $538.3 million.

[15] *Id.* at 11-12.

V. BASIS FOR EVALUATION

Q. WHAT STANDARD DID YOU APPLY IN YOUR EVALUATION OF SPS'S RESILIENCY PLAN APPLICATION?

A. The basis for my evaluation of SPS's application is whether its request is consistent with the terms of PURA § 38.078, the Resiliency Plan statute. Under PURA § 38.078, the Commission must consider the extent to which the plan is expected to enhance system resiliency, including whether the plan prioritizes areas of lower performance and the estimated costs of implementing the measures proposed in the plan. The Commission may approve a plan only if it determines that the plan is in the public interest. The plan is intended to prevent, withstand, mitigate, or more promptly recover from the risks posed by resiliency events to a utility's transmission and distribution systems.[16]

Q. HOW SHOULD SPS'S APPLICATION BE EVALUATED?

A. SPS's application should be evaluated on:

- whether the Plan includes only measures prescribed by the statute;
- whether the Plan prioritizes areas of lower performance, including the extent to which the resiliency plan prioritizes critical load;
- whether the measures can be distinguished from similar existing programs;
- the estimated time and costs of implementing the measures proposed in the Plan and whether the measures are cost effective;
- the verifiability and severity of the resiliency risks posed by the resiliency events the Plan is designed to address;
- the extent to which the plan will enhance resiliency of the electric utility's system, mitigate system restoration costs, reduce the frequency or duration of outages, or improve overall service reliability for customers during and following a resiliency event;
- whether there are more efficient, cost-effective, or otherwise superior means of preventing, withstanding, mitigating, or more promptly recovering from the risks posed by the resiliency events; and

[16] 16 Tex. Admin. Code §25.62(c).

• whether the Plan is in the public interest.

Q. WHY IS IT IMPORTANT THAT THE PLAN MEET THE CRITERIA YOU JUST DESCRIBED?

A. There are several reasons. First, the Legislature established specific criteria for measures to be included in the Plan, and it is necessary that the Plan conform with those criteria. Second, the Legislature provided extraordinary regulatory relief in the form of a regulatory asset for recovery of costs incurred under the Plan. Costs that do not comply with the criteria should not be afforded that same regulatory relief. Third, the projected cost of $538.3 million to implement the Company's Plan is substantial given the number of customers it serves. SPS estimates that the first-year revenue requirement impact of its Plan will increase residential customer bills by a significant $10.94 per month.[17] Ratepayers should not be expected to pay more than is necessary to implement the Resiliency Plan.

Q. HOW DO SPS'S COSTS COMPARE TO OTHER PLANS?

A. I compared the Company's requested Resiliency Plan costs to the costs of other utility resiliency plans. These costs are summarized in Table 2:

Table 2

Docket No.	Utility	Cost ($ million)	No. of Customers	$ per Customer
57463	SPS	$538.3[18]	280,000[19]	1,922[20]
56545	Oncor	$3,412[21]	4,000,000[22]	853[23]

17 Response to TIEC RFI 1-3.

18 *Application of Southwestern Public Service Company for Approval of a System Resiliency Plan*, Docket No. 57463, at 3 (Dec. 30, 2024).

19 *Id.* at 8 (Dec. 30, 2024).

20 $538.3 million / 280,000 customers = $1,922.5 per customer.

21 *Application of Oncor Electric Delivery Company LLC for Approval of a System Resiliency Plan*, Docket No. 56545, Application of Oncor Electric Delivery Company LLC for Approval of a System Resiliency Plan (Application) at 6 (Bates 7) (May 6, 2024).

22 *Id*. at 2 (Bates 3).

23 $3.412 billion / 4,000,000 customers = $853 per customer.

56548	CenterPoint	$2,278[24]	2,800,000[25]	814[26]
56735	Entergy Texas	$335[27]	512,000[28]	654[29]
56954	TNMP	$751[30]	270,000[31]	2,782[32]
57057	AEP Texas	$352[33]	1,100,000[34]	320[35]
57259	SWEPCO	$183[36]	192,000[37]	953[38]

Behind TNMP, SPS has the second-highest average SRP cost per customer of all utilities with SRP filings. Although I am aware that resiliency programs are utility-specific and in particular SPS claims it has a low customer density which can drive up the cost per customer,[39] the statute provides detailed parameters for allowed programs so I would expect that the implementation costs should fall within a reasonably narrow range. The high cost per customer invites a closer look into SPS's proposed measures.

[24] *Application of CenterPoint Energy Houston Electric, LLC for Approval of its Transmission and Distribution System Resiliency Plan*, Docket No. 56548, Application of CenterPoint Energy Houston Electric, LLC for Approval of its Transmission and Distribution System Resiliency Plan at 2 (Apr. 29, 2024).

[25] *Id*. at 5.

[26] $2.278 billion / 2,800,000 customers = $814 per customer.

[27] *Application of Entergy Texas, Inc. for Approval of a Resiliency Plan*, Docket No. 56735, Application of Entergy Texas, Inc. for Approval of a Resiliency Plan at 5 (Jun. 21, 2024).

[28] *Id*., Attachment A at 9.

[29] $335 million / 512,000 customers = $654 per customer.

[30] *Application of Texas-New Mexico Power Company for Approval of a System Resiliency Plan*, Docket No. 56954, Application of Texas-New Mexico Power Company for Approval of a System Resiliency Plan at 12 (Aug. 28, 2024).

[31] *Id*. at 5.

[32] $751 million / 270,000 customers = $2,782 per customer.

[33] *Application of AEP Texas, Inc. for Approval of a System Resiliency Plan*, Docket No. 57057, AEP Texas Inc.'s Petition for Approval of a System Resiliency Plan (Application) at 6-7 (Sep. 25, 2024).

[34] *Id*. at 1.

[35] $352 million / 1,100,000 customers = $320 per customer.

[36] *Application of Southwestern Electric Power Company for Approval of a System Resiliency Plan*, Docket No. 57259, at 6 (November 21, 2024).

[37] *Id*., Attachment A (System Resiliency Plan) at 1.

[38] $183 million / 192,000 customers = $953 per customer.

[39] System Resiliency Plan at 5.

VI. EVALUATION OF THE PLAN

Q. HAVE YOU REVIEWED SPS'S PROPOSED RESILIENCY PLAN?

A. Yes, I have.

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO THE PLAN?

A. Yes. I recommend several adjustments to conform the Plan to the statutory requirements. My adjustments follow the order of the Company's presentation of measures in its requested Resiliency Plan. Importantly, the adjustments I recommend are not "disallowances" of costs, since none of the proposed measures have yet been implemented. Instead, my adjustments represent the removal of certain activities and the associated estimated costs from the proposed Resiliency Plan. The Company may still seek recovery of the costs associated with these activities in rates, but the costs will not be included in the Resiliency Plan regulatory asset.

Q. WHAT DOES SPS CONSIDER TO BE THE PRIMARY VULNERABILITIES OF ITS DISTRIBUTION SYSTEM?

A. SPS considers the number of assets exposed to resiliency events, age of the infrastructure, vegetation density, accessibility to system assets, customer count, and structural loading of infrastructure to be its primary vulnerabilities.[40]

Q. HOW DOES SPS'S PROPOSED PLAN ADDRESS THESE VULNERABILITIES?

A. The Company states the proposed SRP will reduce the frequency of power outages and outage times; provide cost savings from decreased storm recovery costs and expensive emergency repairs; harden the infrastructure and equipment to withstand weather events and other threats; improve overall safety, reliability and system stability; and result in a more modern and flexible system that can better serve customers.[41]

Q. DOES SPS ALREADY UNDERTAKE RESILIENCY ACTIVITIES?

A. Yes. SPS currently undertakes a number of activities to address system resiliency improvements. These include:

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[40] 1898 & Co's SPS System Resiliency Investment Study Report at 42.

[41] System Resiliency Plan at 4.

1. In 2014, SPS updated its construction standards, transitioning from Grade C to Grade B construction for all new and rebuilt overhead facilities. This means that all overhead lines installed since 2014 are hardened to SPS's highest standard, making them better able to withstand and mitigate resiliency events that impact the SPS service area.[42]

2. As a part of its Wood Pole Inspection and Treatment Program, SPS has invested approximately $109 million to replace over 21,000 wooden poles since 2020. According to SPS, pole failures contributed to the largest amount of CMI from 2020-2022, so pole inspections play an important role in identifying and mitigating pole failures.[43]

3. Since 2017, SPS has conducted a routine overhead system maintenance program, where the Company performs circuit assessments and any necessary rebuilds to resolve identified defects. This program reviews the entire SPS distribution system every three to five years, with the primary focus on assessment of overhead pole equipment.[44]

4. SPS conducts a Feeder Performance Improvement Program (FPIP) to identify the worst performing feeders in SPS's service territory and create capital projects to improve their reliability. SPS compiles an annual list of distribution feeders, ranks them and completes a detailed engineering analysis to identify beneficial upgrades.[45]

5. SPS's ongoing Advanced Capital Projects initiative was formalized in 2021[46] and identifies facilities and areas of the system that need additional hardening based on specific input from SPS personnel regarding issues such as line condition, operating concerns, flexibility, and customer impact.[47]

6. Under SPS's Fault Location Isolation and Service Restoration (FLISR) project, SPS uses data from its Advanced Distribution Management System (ADMS) to identify distribution feeders for modernization and equips selected facilities with

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[42] *Id.* at 37.

[43] *Id.*

[44] *Id.* at 38.

[45] *Id.*

[46] Response to TIEC RFI 2-5.

[47] System Resiliency Plan at 38.

automated field devices that are integrated with the ADMS, allowing SPS to remotely monitor system conditions and control devices.[48]

Q. PLEASE DESCRIBE THE MEASURES REFLECTED IN SPS'S PLAN.

A. I describe the measures in the following section of my testimony.

1. Distribution Overhead Hardening

Q. PLEASE BRIEFLY DESCRIBE THIS MEASURE.

A. SPS explains that its Distribution Overhead Hardening Measure includes a comprehensive look at each protection zone along the feeder, identifies deficiencies in the construction, and rebuilds all facilities needed to upgrade the zone to SPS's current standards.[49] This measure is intended to include replacing distribution poles, conductor, line transformers, and open wire secondary; trussing/reinforcing distribution poles; adding new poles to mitigate long span-lengths; wrapping poles to mitigate external wildfire risks in areas of heightened wildfire risk; and replacing arrestors and transformer fuses with non-expulsion alternatives to prevent ignitions in areas of heightened wildfire risk.[50]

Q. WHAT BENEFITS DOES SPS CLAIM UNDER THIS MEASURE?

A. SPS claims that the measure will enhance the structural integrity of SPS's overhead infrastructure to prevent, withstand, and mitigate weather-based resiliency events and wildfire risks.[51] SPS expects the pole replacements, additions, and reinforcement under this measure will reduce span lengths and make rebuilt facilities more capable of surviving an extreme weather event that can cause structural overloading.[52] Conductor upgrades are expected to increase structural integrity and provide additional capacity to prevent thermal overloads and facilitate load transfers during heat and cold events. The additional structural integrity from these activities is intended to reduce the likelihood of conductor contact or broken equipment igniting a wildfire.[53] Replacing fuses and arrestors with non-expulsion

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[48] *Id.*

[49] *Id.* at 39.

[50] *Id.*

[51] *Id.* at 40.

[52] *Id.*

[53] *Id.*

alternatives in areas of heightened wildfire risk is also intended to reduce ignition risk, and pole wraps in areas of heightened wildfire risk should help protect facilities from external wildfire damage.[54] Table 3 summarizes the results of SPS's benefit-cost analysis for the projects included in this measure:[55]

Table 3

Program	Average Benefit Cost Ratio (BCR)	Minimum BCR	Average Customer Minutes of Interruption (CMI) Reduction	Avoided Restoration Costs
Distribution Overhead Hardening	**4.7**	**3.22**	**58%**	**76%**

Q. HOW DOES SPS DISTINGUISH THIS MEASURE FROM ITS EXISTING RESILIENCY ACTIVITIES?

A. SPS explains that the Wood Pole Inspection and Treatment program and the Routine Overhead Maintenance programs I described earlier involve periodic inspections and replacements of individual assets. SPS argues these programs are intended to prevent point failures based on asset condition, not to provide comprehensive hardening for a protection zone. Furthermore, the Company asserts that circuit rebuilds under FPIP address only the worst performing feeders on the SPS system, while the Distribution Overhead Hardening measure will target specific protection zones for comprehensive rebuilds to harden the entire zone. SPS also notes that the wildfire-specific activities in areas of heightened wildfire risk are not part of the existing programs. And because SPS is selecting protection zones for rebuilds based on the BCR, this measure will target the facilities that provide the greatest net resiliency benefit for customers, not necessarily those with the worst historical performance.

[54] *Id.*

[55] *Id.* at 48.

Q. IS SPS'S REQUESTED MEASURE REASONABLE?

A. I do not oppose this measure, but I am concerned that the measure is essentially an expansion of existing, ongoing programs. Moreover, the costs proposed under this measure represent nearly half of SPS's total resiliency plan cost.[56] The rule requires that, if a resiliency plan includes measures that are similar to other existing programs or measures, the utility must distinguish the measures in the resiliency plan from these programs and measures and, if appropriate, explain how the related items work in conjunction with one another.[57] SPS tries to explain that its existing programs target specific locations or feeders and are not comprehensive in scope. But at the end of the day these existing programs result in overall improvements in resiliency. Furthermore, SPS argues that the measure will work in conjunction with the existing programs because the measure will face fewer facilities that do not meet current standards or will address facilities that are not subject to other programs. But SPS provides no bright line between existing programs and those proposed under this measure.

Q. WHAT DO YOU RECOMMEND?

A. First, as I described earlier in my testimony, SPS's SRP request is among the highest cost per customer of all utilities filing an SRP and the costs under the Company's Distribution Overhead Hardening measure accounts for nearly half of SPS's total request. Thus, the costs under this measure can be reduced to provide some relief to customers. SPS did not provide its distribution overhead hardening costs by activity. But in its Plan, SPS did assess wildfire risk to the SPS System and prioritized programs that would maximize wildfire mitigation. It established three operational tiers, from Tier 1 (low risk) to Tier 3 (high risk).[58] I recommend that costs for activities within the Tier 1 (low) wildfire risk area be removed. This amount is $17.8 million[59] and removing these costs will not affect SPS's wildfire mitigation goal.

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[56] *See* Table 1.

[57] 16 TAC § 25.62(c)(2)(D).

[58] System Resiliency Plan at 9.

[59] SPS System Resiliency Investment Study Report at 149.

Second, to avoid the overlap of programs and duplication of costs, I recommend that SPS separately track the distribution overhead hardening measure costs under 1) its existing programs, and 2) the hardening measures proposed in its Plan. The Company should report these separate activities at a time and in a format specified by the Commission. If the report demonstrates that overlap has occurred, this provides the Commission with the information necessary to adjust SPS's costs and/or rates in a future proceeding.

2. <u>Distribution System Protection Modernization</u>

Q. PLEASE BRIEFLY DESCRIBE THIS MEASURE.

A. SPS designed its Distribution System Protection Modernization measure to lessen the impact of infrastructure failures. The measure includes two programs intended to reduce the customer impacts of outages: (1) Mainline Automated Reclosing Deployment and (2) Lateral Reclosing Deployment.[60]

Q. WHAT BENEFITS DOES SPS CLAIM UNDER THIS MEASURE?

A. The Distribution System Protection Modernization measure addresses the resiliency risks associated with extreme weather events. This measure is intended to focus on mitigating and more promptly recovering, primarily through the use of reclosers and communications equipment to enable sectionalization, load transfer, and remote monitoring and control of the SPS system.[61] Table 5 summarizes the expected benefits under this measure:[62]

Table 5

Program	Average BCR	Minimum BCR	Average CMI Reduction	Avoided Restoration Costs
Mainline Automated Reclosing Deployment	**4.2**	**0.9**	**37%**	**68%**

[60] System Resiliency Plan at 54.

[61] *Id.* at 55.

[62] *Id*. at 61.

Lateral Reclosing Deployment	**1.8**	**0.9**	**21%**	**100%**

Q. HOW DOES SPS DISTINGUISH THIS MEASURE FROM ITS EXISTING RESILIENCY ACTIVITIES?

A. SPS explains that the Distribution System Protection Modernization Measure will work in conjunction with the FLISR program,[63] which I described earlier in my testimony. SPS argues that the work proposed in this measure is incremental to FLISR work and will broaden SPS's deployment of communications-enabled field devices to circuits with demonstrated net benefits for customers.[64] Finally, SPS asserts this measure also includes additional work in the substation that is not part of the FLISR program.[65]

Q. IS SPS'S REQUESTED MEASURE REASONABLE?

A. I do not oppose this measure, but I am concerned that the measure is essentially an expansion of an existing, ongoing program. As SPS indicated, its FLISR project uses data from its ADMS to identify distribution feeders for modernization and equips selected facilities with automated field devices that are integrated with the ADMS, allowing SPS to remotely monitor system conditions and control devices.[66] This is exactly what SPS proposes under its Modernization measure. In addition, SPS is requesting funding activities at or above a BCR of 0.9, indicating that for some projects, the expected customer benefits are only 90% of the estimated costs. SPS contends that qualitative benefits make up the remaining 10% but was not able to quantify or monetize these alleged benefits.[67]

Q. WHAT DO YOU RECOMMEND?

A. First, it is not reasonable to include projects with a BCR of less than 1.0 in the SRP, especially since SPS is unable to verify that its "qualitative" benefits make up the difference. SPS provided investment resulting in a BCR $\geq$ 1.0 and a BCR $\geq$ 0.9 for this

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63 *Id*. at 64.

64 *Id*. at 65.

65 *Id*.

66 *Id*. at 38.

67 Response to TIEC RFI 2-22.

measure.[68] I recommend that the difference in investment, representing the investment for projects with a BCR< 1.0, be removed. This amount is $3.9 million.[69]

Second, to avoid the overlap of programs and duplication of costs, I recommend that SPS separately track the Distribution System Protection Modernization measure costs under 1) its existing programs, and 2) the measures proposed in its Plan. The Company should report these separate activities at a time and in a format specified by the Commission. If the report demonstrates that overlap has occurred, this provides the Commission with the information necessary to adjust SPS's costs and/or rates in a future proceeding.

3. Communication Modernization

Q. PLEASE BRIEFLY DESCRIBE THIS MEASURE.

A. SPS explains that the Communication Modernization measure consists of investments in private communications infrastructure to modernize SPS's operational technology communications, including building out a private LTE (pLTE) cellular network.[70]

Q. WHAT BENEFITS DOES SWEPCO CLAIM UNDER THIS MEASURE?

A. The Company believes the proliferation of connected devices presents opportunities to provide value for customers through applications such as automated switching, enhanced powerline safety settings (EPSS), and advanced metering. But SPS contends these devices require a reliable, and reliably available, communications network to connect them to SPS's ADMS. It is the Company's position that public cellular networks provide inadequate coverage across much of its rural, sparsely populated service area to deploy the devices on a widespread basis. SPS also asserts that reliance on a third-party cellular network presents cybersecurity risks for SPS's critical infrastructure.[71]

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68 SPS System Resiliency Investment Study Report at 146.

69 ($76.1 million + $1.7 million) – ($79.7 million + $2.0 million) = $3.9 million.

70 System Resiliency Plan at 66.

71 *Id.*

Q. DID SPS CALCULATE A BCR FOR ITS COMMUNICATION MODERNIZATION MEASURE?

A. No. SPS explains that the Communication Modernization investment enables the full effectiveness of the Mainline Automated Reclosing Deployment program under its proposed Distribution System Protection Modernization measure. SPS points out that its System Resiliency Investment Study Report shows a BCR of 4.3 for the mainline automation program alone,[72] but the combined BCR for Communication Modernization and Mainline Automated Reclosing Deployment is 1.8.[73] This is because the benefits are attributable to the Reclosing Deployment but the cost is for both the Reclosing Deployment and Communication Modernization.

Q. HOW DOES SPS DISTINGUISH THIS MEASURE FROM ITS EXISTING RESILIENCY ACTIVITIES?

A. SPS explained that it has been deploying private fiber for communications between substations and control systems, as well as microwave installations for point-to-point communications for many years, but these solutions provide a different set of capabilities from pLTE and neither can provide communications to field devices across the distribution system. In addition, SPS currently relies on circuit-level communications and public cellular networks to enable communication between devices across most of its system and these solutions will continue to play a role in providing backup communications or communications in areas not covered by the pLTE network. SPS argues that the Communication Modernization measure is distinct from these approaches because it involves development of an integrated private communications network. Finally, SPS admitted it recently began initial development of its pLTE network, but this will not be included in the program proposed in the SRP.[74]

Q. IS SPS'S REQUESTED MEASURE REASONABLE?

A. I do not oppose this measure but point out that SPS functionalizes the $112.7 million in capital investment between Transmission plant ($16.6 million) and General plant ($96.1

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72 SPS System Resiliency Investment Study Report at 136.

73 *Id.* at 143-144.

74 System Resiliency Plan at 75.

million).[75] Other than a secondary allocation of General plant to the Distribution function, which SPS did not provide, these costs should not be included in the Distribution regulatory asset.

Q. WHAT DO YOU RECOMMEND?

A. Unless SPS can provide a supportable basis to allocate any of this capital investment to Distribution, I recommend these costs should not be included in the Distribution regulatory asset.

4. Operational Flexibility

Q. PLEASE BRIEFLY DESCRIBE THIS MEASURE.

A. The Operational Flexibility measure consists of two programs that SPS asserts will make its system more resilient by providing additional flexibility in managing power disruptions when an outage occurs. The first program, the Mobile Substation Equipment Procurement program, will allow SPS to procure additional mobile substation equipment to enable quicker restoration of power during equipment failures at SPS substations. The second program, the Installation of Transmission Switches program, will allow SPS to install additional transmission switches to increase SPS's ability to sectionalize and isolate faults on the transmission system, which should reduce the customer impacts of outages and accelerating service restoration for customers by isolating damaged sections.[76]

Q. WHAT BENEFITS DOES SPS CLAIM UNDER THIS MEASURE?

A. SPS designed the Operational Flexibility Measure to mitigate and more promptly recover from the risks posed by weather-based resiliency events. Specifically, this measure is intended to address risks that result in outages on the transmission system and at SPS substations.[77]

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[75] Response to TIEC RFI 1-2.

[76] System Resiliency Plan at 76.

[77] *Id.* at 77.

Q. DID SPS CALCULATE A BCR FOR ITS OPERATIONAL FLEXIBILITY MEASURE?

A. No. This measure was not evaluated by SPS's consultant 1898 & Co.,[78] so no BCR was developed.

Q. HOW DOES SPS DISTINGUISH THIS MEASURE FROM ITS EXISTING RESILIENCY ACTIVITIES?

A. SPS already deploys a fleet of 12 mobile substations[79] and has 4 more already on order.[80] SPS's request will expand SPS's fleet by 6 additional mobile substations.[81] SPS's current transmission switch installation work addresses: (1) the replacement of existing switches due to age or defect through end of life replacement and (2) installations on newly installed taps. SPS does not have an existing program to proactively install transmission switches on existing transmission facilities.[82]

Q. IS SPS'S REQUESTED MEASURE REASONABLE?

A. While SPS reports that it has identified a need for additional mobile substations,[83] it admits that it has never had a single resiliency event that required every mobile substation in its fleet to be deployed in response.[84] Over the last three years, SPS has deployed its mobile substations an average of just 20 times per year.[85] In addition, while SPS suggests the new mobile substations will allow SPS to retire aging units,[86] it does not plan to retire any assets while they are still functional.[87] SPS has not shown that the additional 6 mobile substations are necessary or provide any additional resiliency benefit. Furthermore, the requested $43.7 million in capital costs is split between Transmission ($24.1 million) and

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78 Application at 3.

79 Direct Testimony of Brianne Jole at 40.

80 Response to TIEC RFI 2-12.

81 Direct Testimony of Brianne Jole at 39.

82 System Resiliency Plan at 84.

83 *Id.* at 78.

84 Response to TIEC 2-37.

85 System Resiliency Plan at 78.

86 Direct Testimony of Brianne Jole at 40.

87 Response to TIEC RFI 2-35.

Distribution ($19.6 million), so if approved, only the Distribution portion can be included in the Distribution regulatory asset.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the 6 additional mobile substations requested by SPS be rejected, as SPS has not shown them to be necessary or provide any additional resiliency benefit. The capital cost of the mobile substations is $30.8 million.[88] If the Commission determines to approve procurement of the additional mobile substations, then I recommend only the amounts functionalized to Distribution be included in the regulatory asset.

5. <u>Wildfire Mitigation</u>

Q. PLEASE BRIEFLY DESCRIBE THIS MEASURE.

A. SPS proposes two programs under its Wildfire Mitigation measure: (1) Wildfire Situational Awareness and (2) Wildfire Physical Mitigations. The Wildfire Situational Awareness program includes activities that are intended to help SPS assess its wildfire risk by monitoring forecasted and real time fire danger and fire weather conditions and monitoring of SPS assets and to better understand wildfire risk on the landscape relative to populated areas and SPS facilities. Activities include wildfire risk mapping, enhanced meteorology capabilities, weather and fire science modeling, and AI cameras. The Wildfire Physical Mitigation program encompasses activities that help SPS mitigate potential utility ignition sources (prevention) and physical risks to the equipment used in its service area from passing wildfire (protection). Activities include defensible space around poles (DSAP), wood substation conversion, and transmission wildfire detailed inspections.[89] In addition, SPS incorporates a number of wildfire mitigation-related programs in its other SRP measures.[90]

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[88] Direct Testimony of Brianne Jole at 39.

[89] System Resiliency Plan at 86.

[90] *Id.* at 85.

Q. WHAT BENEFITS DOES SPS CLAIM UNDER THIS MEASURE?

A. The expected benefits of this measure include reducing the frequency and duration of customer outages caused by wildfires, reducing restoration costs, and improving overall service reliability for customers.[91]

Q. DID SPS CALCULATE A BCR FOR ITS WILDFIRE MITIGATION MEASURE?

A. No. This measure was not evaluated by SPS's consultant 1898 & Co.,[92] so no BCR was developed.

Q. HOW DOES SPS DISTINGUISH THIS MEASURE FROM ITS EXISTING RESILIENCY ACTIVITIES?

A. SPS recognizes that some of the programs under this measure are similar to SPS's existing programs for wildfire mitigation, but argues that the programs are on a "quicker cadence" in order to enable SPS to more quickly and efficiently mitigate risks. SPS also points out that it is able to derive significant benefits by drawing on the experiences of SPS's affiliate, Public Service Company of Colorado, which has a robust wildfire mitigation program which encompasses many of the same programs that SPS has included in this SRP.[93]

Q. IS SPS'S REQUESTED MEASURE REASONABLE?

A. Yes, SPS's wildfire mitigation measure is reasonable. It envisions a broad range of programs to mitigate the impact of wildfires. It is important to note that SPS's current vegetation management budget, which parallels a component of SPS's physical mitigation program, is only $2.1 million.[94] SPS's request will add $19.8 million in capital costs and $16.8 million in operation and maintenance (O&M) expense to address wildfire mitigation. However, while the capital costs are all allocated to Distribution, the O&M expense is allocated to Transmission ($3.3 million) and Distribution ($13.5 million). This allocation should be reflected in the regulatory asset.

[91] *Id*. at 100.

[92] Application at 3.

[93] System Resiliency Plan at 103.

[94] Project No. 41381, SPS Annual Report on Vegetation Management at 7 (May 1, 2024).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that SPS's proposed wildfire mitigation measure be approved, subject to the proper allocation of costs between the Transmission and Distribution functions.

6. <u>Summary</u>

Q. CAN YOU SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS TO SPS'S PLAN?

A. Yes. My recommended adjustments are summarized in Table 6:

Table 6

Resiliency Measure	Requested Capital Costs(millions)	Adjustment to Capital Costs (millions)	Requested O&M Expense (millions)	Adjustment to O&M Expense (millions)
Distribution Overhead Hardening	$253.0	($17.8)	$0	$0
Distribution System Protection Modernization	$92.3	($3.9)	$0	$0
Communication Modernization	$112.7	$0 (1)	$0	$0
Operational Flexibility	$43.7	($30.8) (2)	$0.006	$0
Wildfire Mitigation	$19.8	$0	$16.8	$0 (3)
Total	$521.5	($52.5)	$16.8	$0

(1) No adjustment but capital costs are split between Transmission plant ($16.6 million) and General plant ($96.1 million). SPS has not provided support for any allocation to Distribution.

(2) These capital costs should be split between Transmission plant and Distribution plant, but SPS has not provided support for any allocation.

(3) No adjustment but O&M expenses are split between Transmission ($3.3 million) and Distribution ($13.5 million).

VII. <u>EVALUATION METRICS</u>

Q. PLEASE SUMMARIZE THE METRICS PROPOSED BY SPS.

A. The metrics proposed by SPS include:[95]

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95 *Id.* at 105-107.

1. **Underperforming Area Count.** Identifies the number of underperforming areas across the SPS System. This metric applies to all resiliency measures except Wildfire Mitigation.

2. **Rolling 10-Year Average SAIDI.** Calculates the average duration of all outage events over the last 10 years, normalized for customer counts. This metric applies to all resiliency measures except Wildfire Mitigation.

3. **Storm Restoration Duration.** Calculates an average storm restoration duration for Major Event Days. Each year, a new average restoration duration is calculated and compared with the average durations from the previous three years. This metric applies to all resiliency measures except Wildfire Mitigation.

4. **Average Hardened Protection Zone (AHPZ) CI vs Average Protection Zone (APZ) CI Comparison by County (Hardened Only).** Compares hardened protection zones with non-hardened protection zones. This metric applies to the Distribution System Resiliency measures.

5. **AHPZ CI Percentage Improvement.** Estimates the performance improvement between non-hardened protection zones and hardened protection zones. This metric includes all interruptions and applies to the Distribution System Resiliency measures.

6. **RAN Tower Completion.** SPS will report cellular tower construction completion, testing, and in-servicing as compared to the SRP.

7. **End Device Connectivity.** SPS will report connectivity of end devices to PLTE cellular towers, including acceptance from the business unit on end-to-end testing validation in accordance with the Plan.

8. **Units Completed in DSAP.** SPS will calculate and report the number of units identified and completed in Tiers 2 and 3 for DSAP compared to the Plan.

9. **Transmission Inspections.** Detailed inspections executed in Tier 2 and 3 wildfire areas, with associated number of emergency and high-priority defects identified and remediated.

Q. DO YOU RECOMMEND ANY ADJUSTMENTS TO SPS'S PROPOSED METRICS?

A. Yes. SPS's metrics need more specificity on measuring the effectiveness of its measures.

Q. WHAT ARE YOUR ADJUSTMENTS?

A. First, while I agree that tracking SAIDI is an important metric, a rolling 10-year average dilutes the impact on SAIDI. SAIDI should be tracked no longer than on a rolling 3-year average. In addition, SPS should also measure a rolling 3-year average SAIFI. Both the frequency and duration of outages provide important information on SPS's ability to improve system resiliency.

Q. DO YOU HAVE AN ADDITIONAL ADJUSTMENT?

A. Yes. SPS referred to the wildfire mitigation plan approved for its affiliate Public Service Company of Colorado. That plan, approved by the Public Utilities Commission of Colorado, included several metrics that should be considered by the Commission in SPS's proposed SRP. These metrics include:[96]

- The number of ignitions associated with electric overhead power lines within each wildfire risk Tier;
- The number of downed transmission and distribution wires within each wildfire risk Tier;
- The total number of wildfires in the Company's service territory;
- Percentage on-cycle vegetation management activities for transmission and distribution assets in each wildfire risk Tier.

VIII. <u>RATE CASE EXPENSES</u>

Q. WHAT IS THE PURPOSE OF ADDRESSING RATE CASE EXPENSES IN THIS PROCEEDING?

A. The purpose of addressing rate case expenses in this proceeding is to comply with PURA § 33.023, which states:

(a) The governing body of a municipality participating in or conducting a ratemaking proceeding may engage rate consultants, accountants, auditors, attorneys, and engineers to:

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96 *In the Matter of the Application of Public Service Company of Colorado for Approval of Wildfire Mitigation Plan and Wildfire Protection Rider,* Proceeding No. 20A-0300E, Decision No. R21-0109 (Feb. 26, 2021).

> *(1) conduct investigations, present evidence, and advise and represent the governing body; and*
>
> *(2) assist the governing body with litigation in an electric utility ratemaking proceeding before the governing body, a regulatory authority, or a court.*
>
> *(b) The electric utility in the ratemaking proceeding shall reimburse the governing body of the municipality for the reasonable cost of the services of a person engaged under Subsection (a) to the extent the applicable regulatory authority determines is reasonable.*

Q. HOW MUCH OF AXM'S REQUESTED RATE CASE EXPENSES ARE ATTRIBUTABLE TO REC?

A. REC has spent time reviewing the application testimony, schedules and workpapers, reviewing discovery, analyzing the filing, preparing recommendations and conferring with counsel. As of January 31, 2025, REC has not yet submitted any invoices for this assignment.

Q. PLEASE IDENTIFY THE REC STAFF WHO INCURRED EXPENSES IN THIS CASE, THEIR HOURLY RATES, AND TOTAL HOURS BILLED.

A. I am leading the review for REC, and my billing rate is $280 per hour. As discussed in my pervious answer, I have not yet submitted any invoices for my time on this assignment. However, after January 31, 2025, we will have additional tasks to complete, including preparation of testimony, reviewing and potentially responding to discovery, preparation for hearing, settlement negotiations and supporting post hearing filings.

Q. WHAT CRITERIA MUST BE MET UNDER THE COMMISSION'S RATE CASE EXPENSE RULE (16 TEXAS ADMINISTRATIVE CODE § 25.245)?

A. The following criteria are set out in the rule:

1. Whether the fees paid to, tasks performed by, or time spent on a task by an attorney or other professional were extreme or excessive,
2. Whether the expenses incurred for lodging, meals and beverages, transportation, or other services or materials were extreme or excessive,
3. Whether there was duplication of services or testimony,

4. Whether the utility's or municipality's proposal on an issue in the rate case had no reasonable basis in law, policy, or fact and was not warranted by any reasonable argument for the extension, modification, or reversal of commission precedent,

5. Whether rate-case expenses as a whole were disproportionate, excessive, or unwarranted in relation to the nature and scope of the rate case addressed by 1 the evidence pursuant to subsection (b)(5) of this section, or

6. Whether the utility or municipality failed to comply with the requirements for providing sufficient information pursuant to subsection (b) of this section.

Q. IN LIGHT OF THE FIRST CRITERION SET OUT IN YOUR PREVIOUS ANSWER, IS YOUR BILLING RATE AND THE TIME SPENT ON THE TASKS IN THIS CASE REASONABLE?

A. Yes. My billing rate is reasonable. This is my normal billing rate for services provided to similar clients. This rate is in the range of billing rates charged by other consultants with similar experience and is reasonable for a consultant providing these types of services before utility regulatory agencies in Texas. My hourly rate is especially reasonable given that I have more than 35 years of utility rate regulatory experience.

Q. IN LIGHT OF THE SECOND CRITERION, DO REC'S EXPENSES INCLUDE ANY TYPE OF IDENTIFIED CHARGES OR CHARGES THE COMMISSION HAS EXCLUDED IN THE PAST?

A. No. REC's charges are entirely for professional fees. There are no other expenses included on our invoices.

Q. IN LIGHT OF THE THIRD CRITERION, WAS THERE ANY DUPLICATION OF SERVICES OR TESTIMONY?

A. No. AXM provided testimony through one witness. No other city group is participating in this proceeding.

Q. IN LIGHT OF THE FOURTH CRITERION, DID THE ISSUES YOU RAISED HAVE A REASONABLE BASIS IN LAW, POLICY, OR FACT?

A. Yes. The issues raised in my testimony focus directly on whether SPS's Resiliency Plan was in the public interest.

Q. IN LIGHT OF THE FIFTH CRITERION, WHAT IS YOUR CONCLUSION REGARDING REC'S ACTUAL CHARGES?

A. In my opinion, the work performed by REC through January 31, 2025, although not yet invoiced, is reasonable and necessary and not disproportionate, excessive, or unwarranted in relation to the nature and scope of the rate filing. Furthermore, to the best of my knowledge, I have fully complied with the information requirements set out in the sixth criterion.

Q. DID AXM ALSO INCUR EXPENSES FOR LEGAL SERVICES IN THIS PROCEEDING?

A. Yes, AXM received and continues to receive legal services from Herrera Law & Associates, PLLC in this proceeding. Herrera Law & Associates will provide an affidavit attesting to the reasonableness of AXM's legal expenses incurred in this matter after the filing of this testimony. Upon request by Commission Staff, Herrera Law & Associates will periodically update their respective rate case expenses, including consultant expenses, and as further directed by the Commission and ALJs.

IX. CONCLUSION

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

SOAH DOCKET NO. 473-25-09020
PUC DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND ATTACHMENTS

OF KARL J. NALEPA

Attachment KJN-1 Summary of Qualifications

KARL J. NALEPA

Mr. Nalepa is an energy economist with more than 40 years of private and public sector experience in the electric and natural gas industries. He has extensive experience analyzing utility rate filings and resource plans with particular focus on fuel and power supply requirements, quality of fuel supply management, and reasonableness of energy costs. Mr. Nalepa developed peak demand and energy forecasts for public utilities and has forecast the price of natural gas in ratemaking and resource plan evaluations. He led a management and performance review of the Texas Public Utility Commission and has conducted performance reviews and valuation studies of municipal utility systems. Mr. Nalepa previously directed the Railroad Commission of Texas' Regulatory Analysis & Policy Section, with responsibility for preparing timely natural gas industry analysis, managing ratemaking proceedings, mediating informal complaints, and overseeing consumer complaint resolution. He has prepared and defended expert testimony in both administrative and civil proceedings and has served as a technical examiner in natural gas rate proceedings.

EDUCATION

1998	Certificate of Mediation Dispute Resolution Center, Austin
1989	NARUC Regulatory Studies Program Michigan State University
1988	M.S. - Petroleum Engineering University of Houston
1980	B.S. - Mineral Economics Pennsylvania State University

PROFESSIONAL HISTORY

2011 -	ReSolved Energy Consulting Partner
2003 - 2011	RJ Covington Consulting Managing Director
1997 – 2003	Railroad Commission of Texas Asst. Director, Regulatory Analysis & Policy
1995 – 1997	Karl J. Nalepa Consulting Principal
1992 – 1995	Resource Management International, Inc. Supervising Consultant
1988 – 1992	Public Utility Commission of Texas Fuels Analyst
1980 – 1988	Transco Exploration Company Reservoir and Evaluation Engineer

AREAS OF EXPERTISE

Regulatory Analysis

Electric Power: Analyzed electric utility rate, certification, and resource forecast filings. Assessed the quality of fuel supply management, and reasonableness of fuel costs recovered from ratepayers. Projected the cost of fuel and purchased power. Estimated the impact of environmental costs on utility resource selection. Participated in regulatory rulemaking activities. Provided expert staff testimony in a number of proceedings before the Texas Public Utility Commission.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the Public Utility Commission. Also assist municipal utilities in preparing and defending requests to change rates and other regulatory matters before the Public Utility Commission.

Natural Gas: Directed the economic regulation of gas utilities in Texas for the Railroad Commission of Texas. Responsible for monitoring, analyzing and reporting on conditions and events in the natural gas industry. Managed Commission staff representing the public interest in contested rate proceedings before the Railroad Commission and acted as technical examiner on behalf of the Commission. Mediated informal disputes between industry participants and directed handling of customer billing and service complaints. Oversaw utility compliance filings and staff rulemaking initiatives. Served as a policy advisor to the Commissioners.

As consultant, represent interests of municipal clients intervening in large utility rate proceedings through analysis of filings and presentation of testimony before the cities and Railroad Commission. Also assist small utilities in preparing and defending requests to change rates and other regulatory matters before the Railroad Commission.

Litigation Support

Retained to support litigation in natural gas contract disputes. Analyzed the results of contract negotiations and competitiveness of gas supply proposals considering gas market conditions contemporaneous with the period reviewed. Supported litigation related to alleged price discrimination related to natural gas sales for regulated customers. Provided analysis of regulatory and accounting issues related to ownership of certain natural gas distribution assets in support of litigation against a natural gas utility. Supported independent power supplier in binding arbitration regarding proper interpretation of a natural gas transportation contract. Provided expert witness testimony in administrative and civil court proceedings.

Utility System Assessment

Led a management and performance review of the Public Utility Commission. Conducted performance reviews and valuation studies of municipal utility systems. Assessed ability to compete in the marketplace and recommended specific actions to improve the competitive position of the utilities. Provided comprehensive support in the potential sale of a municipal gas system, including preparation of a valuation study and all activities leading to negotiation of contract for sale and franchise agreements.

Energy Supply Analysis

Reviewed system requirements and prepared requests for proposals (RFPs) to obtain natural gas and power supplies for both utility and non-utility clients. Evaluated submittals under alternative demand and market conditions and recommended cost-effective supply proposals. Assessed supply strategies to determine optimum mix of available resources.

Econometric Forecasting

Prepared econometric forecasts of peak demand and energy for municipal and electric cooperative utilities in support of system planning activities. Developed forecasts at the rate class and substation levels. Projected price of natural gas by individual supplier for Texas electric and natural gas utilities to support review of utility resource plans.

Reservoir Engineering

Managed certain reserves for a petroleum exploration and production company in Texas. Responsible for field surveillance of producing oil and natural gas properties, including reserve estimation, production forecasting, regulatory reporting, and performance optimization. Performed evaluations of oil and natural gas exploration prospects in Texas and Louisiana.

PROFESSIONAL MEMBERSHIPS

Society of Petroleum Engineers
International Association for Energy Economics
United States Association for Energy Economics

SELECT PUBLICATIONS, PRESENTATIONS, AND TESTIMONY

"Summary of the USAEE Central Texas Chapter's Workshop entitled 'EPA's Proposed Clean Power Plan Rules: Economic Modeling and Effects on the Electric Reliability of Texas Region,'" with Dr. Jay Zarnikau and Mr. Neil McAndrews, USAEE Dialogue, May 2015

"Public Utility Ratemaking," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, September 2013

"What You Should Know About Public Utilities," EBF 401: Strategic Corporate Finance, The Pennsylvania State University, October 2011

"Natural Gas Markets and the Impact on Electricity Prices in ERCOT," Texas Coalition of Cities for Fair Utility Issues, Dallas, October 2008

"Natural Gas Regulatory Policy in Texas," Hungarian Oil and Gas Policy Business Colloquium, U.S. Trade and Development Agency, Houston, May 2003

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2003

"Gas Utility Update," Railroad Commission Regulatory Expo and Open House, October 2002

"Deregulation: A Work in Progress," Interview by Karen Stidger, *Gas Utility Manager*, October 2002

"Regulatory Overview: An Industry Perspective," Southern Gas Association's Ratemaking Process Seminar, Houston, February 2001

"Natural Gas Prices Could Get Squeezed," with Commissioner Charles R. Matthews, *Natural Gas*, December 2000

"Railroad Commission Update," Texas Society of Certified Public Accountants, Austin, April 2000

"A New Approach to Electronic Tariff Access," Association of Texas Intrastate Natural Gas Pipeline Annual Meeting, Houston, January 1999

"A Texas Natural Gas Model," United States Association for Energy Economics North American Conference, Albuquerque, 1998

"Texas Railroad Commission Aiding Gas Industry by Updated Systems, Regulations," *Natural Gas,* July 1998

"Current Trends in Texas Natural Gas Regulation," Natural Gas Producers Association, Midland, 1998

"An Overview of the American Petroleum Industry," Institute of International Education Training Program, Austin, 1993

Direct testimony in PUC Docket No. 10400 summarized in *Environmental Externality,* Energy Research Group for the Edison Electric Institute, 1992

"God's Fuel - Natural Gas Exploration, Production, Transportation and Regulation," with Danny Bivens, Public Utility Commission of Texas Staff Seminar, 1992

"A Summary of Utilities' Positions Regarding the Clean Air Act Amendments of 1990," Industrial Energy Technology Conference, Houston, 1992

"The Clean Air Act Amendments of 1990," Public Utility Commission of Texas Staff Seminar, 1992

SOAH DOCKET NO. 473-25-09020
PUC DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	**§ § § § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND ATTACHMENTS

OF KARL J. NALEPA

Attachment KJN-2 Summary of Previously Filed Testimony

KARL J. NALEPA
TESTIMONY FILED

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Public Utility Commission of Texas					
57299	Feb 25	Cities	WETT	Cost of Service	Cost of Service
57259	Jan 25	CARD	SWEPCO	System Resiliency Plan	Public Interest Review
57057	Nov 24	Cities	AEP Texas	System Resiliency Plan	Public Interest Review
56963	Sep 24	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
56954	Oct 24	Cities	Texas-New Mexico Power	System Resiliency Plan	Public Interest Review
56887	Aug 24	Cities	Texas-New Mexico Power	DCRF	DCRF Methodology
56643	Jan 25	CARD	SWEPCO	Fuel Reconciliation	Fuel Cost Recovery
56595	Jun 24	Xcel Municipalities	Southwestern Public Service	DCRF	DCRF Methodology
56572	Aug 24	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
56548	Jun 24	Cities	CenterPoint Houston	System Resiliency Plan	Public Interest Review
56545	Jul 24	Office of Public Counsel	Oncor Electric Delivery	System Resiliency Plan	Public Interest Review
56428	Apr 24	Cities	Texas-New Mexico Power	DCRF	DCRF Methodology
56425	Apr 24	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
56306	Mar 24	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
56225	Aug 24	City of El Paso	El Paso Electric	GCRR	GCRR Methodology
56165	May 24	Cities	AEP Texas	Cost of Service	Cost of Service
55993	Jan 24	Cities	CenterPoint Energy Houston	DCRF	DCRF Methodology
55973	Jul 24	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel Cost Recovery

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
55629	Nov 23	CARD	SWEPCO	DCRF	DCRF Methodology
55525	Oct 23	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
55176	Mar 24	Office of Public Counsel	El Paso Electric	Business Solar Program	Public Interest Review
55155	Apr 24	Office of Public Counsel	SWEPCO	Remand	Refund Methodology
54950	Aug 23	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
54929	Oct 23	Office of Public Counsel	El Paso Electric	CCN	Public Interest Review
54830	Sep 23	Cities	CenterPoint Energy Houston	TEEEF	TEEEF Cost of Service
54825	Jun 23	Cities	CenterPoint Energy Houston	DCRF	DCRF Methodology
54659	Jun 23	City of El Paso	El Paso Electric	GCRR	GCRR Methodology
54657	Dec 23	Office of Public Counsel	Lubbock Power & Light	TCOS	Wholesale Transmission Rate
54634	Aug 23	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
54282	Jan 23	Xcel Municipalities	Southwestern Public Service	Fuel Surcharge	Appropriate Recovery Period
54234	Jan 23	CARD	SWEPCO	Fuel Surcharge	Appropriate Recovery Period
54057	Mar 23	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost Recovery
54040	Jan 23	CARD	SWEPCO	TCRF	TCRF Methodology
54039	Nov 22	CARD	SWEPCO	DCRF	DCRF Methodology
53931	Mar 23	Office of Public Counsel	SWEPCO	Fuel Reconciliation	Fuel Cost Recovery
53766	Nov 22	Xcel Municipalities	Southwestern Public Service	Rate Surcharge	Appropriate Interest Rate
53719	Oct 22	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
53625	Nov 22	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
53601	Aug 22	Cities	Oncor Electric Delivery	Cost of Service	Revenues / Tariffs / Cost Allocation

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
53551	Aug 22	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
53436	May 22	TNMP Cities	Texas-New Mexico Power	DCRF	DCRF Methodology
53034	Jul 22	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel Cost Recovery
52728	May 22	Office of Public Counsel	City of College Station	TCOS	Wholesale Transmission Rate
52487	Mar 22	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review
52485	Mar 22	Office of Public Counsel	Southwestern Public Service	CCN	Public Interest Review
52195	Oct 21	City of El Paso	El Paso Electric	Cost of Service	Cost of Service Model
52194	July 21	Cities	CenterPoint Energy Houston	EECRF	EECRF Methodology
52178	July 21	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
52081	July 21	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
52067	July 21	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
51997	Aug 21	Office of Public Counsel	Entergy Texas, Inc.	System Restoration Costs	Cost Review
51802	Aug 21	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation
51415	Mar 21	CARD	SWEPCO	Cost of Service	Cost Allocation
51381	Dec 20	Entergy Cities	Entergy Texas Inc.	GCRR	GCRR Methodology
51345	Oct 20	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
51215	Mar 21	Office of Public Counsel	Entergy Texas Inc.	CCN	Public Interest Review
51100	Nov 20	Office of Public Counsel	Lubbock Power & Light	TCOS	Wholesale Transmission Rate
50997	Jan 21	CARD	SWEPCO	Fuel Reconciliation	Fuel Cost Recovery
50790	Jul 20	Office of Public Counsel	Entergy Texas, Inc.	Sale, Transfer, Merger	Public Interest Review
50714	May 20	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
50110	Dec 19	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
49831	Feb 20	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost Allocation
49737	Jan 20	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
49594	Jul 19	Oncor Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
49592	Jul 19	AEP Cities	AEP Texas Inc.	EECRF	EECRF Methodology
49586	Jul 19	TNMP Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
49583	Aug 19	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
49496	Jun 19	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
49494	Jul 19	AEP Cities	AEP Texas Inc.	Cost of Service	Plant Additions
49421	Jun 19	Office of Public Counsel	CenterPoint Energy Houston	Cost of Service	Cost of Service
49395	May 19	City of El Paso	El Paso Electric	DCRF	DCRF Methodology
49148	Apr 19	City of El Paso	El Paso Electric	TCRF	TCRF Methodology
49042	Mar 19	SWEPCO Cities	SWEPCO	TCRF	TCRF Methodology
49041	Feb 19	SWEPCO Cities	SWEPCO	DCRF	DCRF Methodology
48973	May 19	Xcel Municipalities	Southwestern Public Service	Fuel Reconciliation	Fuel / Purch Power Costs
48963	Dec 18	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
48420	Aug 18	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
48404	Jul 18	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
48371	Aug 18	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service
48231	May 18	Cities	Oncor Electric Delivery	DCRF	DCRF Methodology
48226	May 18	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
48222	Apr 18	Cities	AEP Texas Inc.	DCRF	DCRF Methodology
47900	Dec 17	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
47527	Apr 18	Xcel Municipalities	Southwestern Public Service	Cost of Service	Cost of Service
47461	Dec 17	Office of Public Counsel	SWEPCO	CCN	Public Interest Review
47236	Jul 17	Cities	AEP Texas	EECRF	EECRF Methodology
47235	Jul 17	Cities	Oncor Electric Delivery	EECRF	EECRF Methodology
47217	Jul 17	Cities	Texas-New Mexico Power	EECRF	EECRF Methodology
47032	May 17	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
46936	Oct 17	Xcel Municipalities	Southwestern Public Service	CCN	Public Interest Review
46449	Apr 17	Cities	SWEPCO	Cost of Service	Cost of Service
46348	Sep 16	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
46238	Jan 17	Office of Public Counsel	Oncor Electric Delivery	STM	Public Interest Review
46076	Dec 16	Cities	Entergy Texas Inc.	Fuel Reconciliation	Fuel Cost Recovery
46050	Aug 16	Cities	AEP Texas	STM	Public Interest Review
46014	Jul 16	Gulf Coast Coalition	CenterPoint Energy Houston	EECRF	EECRF Methodology
45788	May 16	Cities	AEP-TNC	DCRF	DCRF Methodology
45787	May 16	Cities	AEP-TCC	DCRF	DCRF Methodology
45747	May 16	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
45712	Apr 16	Cities	SWEPCO	DCRF	DCRF Methodology
45691	Jun 16	Cities	SWEPCO	TCRF	TCRF Methodology
45414	Feb 17	Office of Public Counsel	Sharyland	Cost of Service	Cost of Service

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
45248	May 16	City of Fritch	City of Fritch	Cost of Service (water)	Cost of Service
45084	Nov 15	Cities	Entergy Texas Inc.	TCRF	TCRF Methodology
45083	Oct 15	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
45071	Aug 15	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
44941	Dec 15	City of El Paso	El Paso Electric	Cost of Service	CEP Adjustments
44677	Jul 15	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
44572	May 15	Gulf Coast Coalition	CenterPoint Energy Houston	DCRF	DCRF Methodology
44060	May 15	City of Frisco	Brazos Electric Coop	CCN	Transmission Cost Recovery
43695	May 15	Pioneer Natural Resources	Southwestern Public Service	Cost of Service	Cost Allocation
43111	Oct 14	Cities	Entergy Texas Inc.	DCRF	DCRF Methodology
42770	Aug 14	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
42485	Jul 14	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
42449	Jul 14	City of El Paso	El Paso Electric	EECRF	EECRF Methodology
42448	Jul 14	Cities	SWEPCO	TCRF	Transmission Cost Recovery Factor
42370	Dec 14	Cities	SWEPCO	Rate Case Expenses	Rate Case Expenses
41791	Jan 14	Cities	Entergy Texas Inc.	Cost of Service	Cost of Service/Fuel
41539	Jul 13	Cities	AEP Texas North	EECRF	EECRF Methodology
41538	Jul 13	Cities	AEP Texas Central	EECRF	EECRF Methodology
41444	Jul 13	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
41223	Apr 13	Cities	Entergy Texas Inc.	ITC Transfer	Public Interest Review
40627	Nov 12	Austin Energy	Austin Energy	Cost of Service	General Fund Transfers

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
40443	Dec 12	Office of Public Counsel	SWEPCO	Cost of Service	Cost of Service/Fuel
40346	Jul 12	Cities	Entergy Texas Inc.	Join MISO	Public Interest Review
39896	Mar 12	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power
39366	Jul 11	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
38951	Feb 12	Cities	Entergy Texas Inc.	CGS Tariff	CGS Costs
38815	Sep 10	Denton Municipal Electric	Denton Municipal Electric	Interim TCOS	Wholesale Transmission Rate
38480	Nov 10	Cities	Texas-New Mexico Power	Cost of Service	Cost of Service/Rate Design
37744	Jun 10	Cities	Entergy Texas Inc.	Cost of Service/ Fuel Reconciliation	Cost of Service/ Nat Gas/ Purch Power/ Gen
37580	Dec 09	Cities	Entergy Texas Inc.	Fuel Refund	Fuel Refund Methodology
37482	Jan 10	Cities	Entergy Texas Inc.	PCRF	PCRF Methodology
37404	Aug 09	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Corrected TCOS Rate
36956	Jul 09	Cities	Entergy Texas Inc.	EECRF	EECRF Methodology
36392	Nov 08	Texas Municipal Power	Texas Municipal Power	Interim TCOS	Wholesale Transmission Rate
35717	Nov 08	Cities Steering Committee	Oncor Electric Delivery	Cost of Service	Cost of Service/Rate Design
34800	Apr 08	Cities	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Coal/Nuclear
16705	May 97	North Star Steel	Entergy Gulf States	Fuel Reconciliation	Natural Gas/Fuel Oil
10694	Jan 92	PUC Staff	Midwest Electric Coop	Revenue Requirements	Depreciation/ Quality of Service
10473	Sep 91	PUC Staff	HL&P	Notice of Intent	Environmental Costs
10400	Aug 91	PUC Staff	TU Electric	Notice of Intent	Environmental Costs
10092	Mar 91	PUC Staff	HL&P	Fuel Reconciliation	Natural Gas/Fuel Oil

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10035	Jun 91	PUC Staff	West Texas Utilities	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas/Fuel Oil/Coal
9850	Feb 91	PUC Staff	HL&P	Revenue Req. Fuel Factor	Natural Gas/Fuel Oil/ETSI Natural Gas/Coal/Lignite
9561	Aug 90	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
9427	Jul 90	PUC Staff	LCRA	Fuel Factor	Natural Gas
9165	Feb 90	PUC Staff	El Paso Electric	Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas
8900	Jan 90	PUC Staff	SWEPCO	Fuel Reconciliation Fuel Factor	Natural Gas Natural Gas
8702	Sep 89 Jul 89	PUC Staff	Gulf States Utilities	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas/Fuel Oil Natural Gas/Fuel Oil Natural Gas/Fuel Oil
8646	May 89 Jun 89	PUC Staff	Central Power & Light	Fuel Reconciliation Revenue Requirements Fuel Factor	Natural Gas Natural Gas/Fuel Oil Natural Gas
8588	Aug 89	PUC Staff	El Paso Electric	Fuel Reconciliation	Natural Gas

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Railroad Commission of Texas					
18879	Feb 25	Cities	Atmos Energy West Texas	Cost of Service	Cost Allocation/Rate Design
17471	Aug 24	TGS Cities	Texas Gas Service	Cost of Service	Cost Allocation/Rate Design
15513	Mar 24	Cities Served by CenterPoint	CenterPoint Energy Entex	Cost of Service	Consolidation / Cost of Service
13758	Sep 23	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Cost Allocation
09896	Sep 22	City of El Paso	Texas Gas Service	Cost of Service	Consolidation / Cost of Service
07061	Sep 21	Texas Cities Alliance	Multiple	Gas Cost Securitization	Prudence Determination
05509	Dec 20	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10928	Mar 20	TGS Cities	Texas Gas Service	Cost of Service	Cost of Service/Rate Design
10920	Feb 20	East Texas Cities Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10900	Nov 19	Cities Steering Committee	Atmos Energy Triangle	Cost of Service	Cost of Service
10899	Sep 19	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10737	Jun 18	T&L Gas Co.	T&L Gas Co.	Cost of Service	Cost of Service/Rate Design
10622	Apr 17	LDC, LLC	LDC, LLC	Cost of Service	Cost of Service/Rate Design
10617	Mar 17	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10580	Mar 17	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
10567	Feb 17	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10506	Jun 16	City of El Paso	Texas Gas Service	Cost of Service	Cost of Service/Energy Efficiency
10498	Feb 16	NatGas, Inc.	NatGas, Inc.	Cost of Service	Cost of Service/Rate Design
10359	Jul 14	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10295	Oct 13	Cities Steering Committee	Atmos Pipeline Texas	Revenue Rider	Rider Renewal

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
10242	Jan 13	Onalaska Water & Gas	Onalaska Water & Gas	Cost of Service	Cost of Service/Rate Design
10196	Jul 12	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
10190	Jan 13	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10174	Aug 12	Cities Steering Committee	Atmos Energy West Texas	Cost of Service	Cost of Service/Rate Design
10170	Aug 12	Cities Steering Committee	Atmos Energy Mid Tex	Cost of Service	Cost of Service/Rate Design
10106	Oct 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10083	Aug 11	City of Magnolia, Texas	Hughes Natural Gas	Cost of Service	Cost of Service/Rate Design
10038	Feb 11	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
10021	Oct 10	AgriTex Gas, Inc.	AgriTex Gas, Inc.	Cost of Service	Cost of Service/Rate Design
10000	Dec 10	Cities Steering Committee	Atmos Pipeline Texas	Cost of Service	Cost of Service/Rate Design
9902	Oct 09	Gulf Coast Coalition	CenterPoint Energy Entex	Cost of Service	Cost of Service/Rate Design
9810	Jul 08	Bluebonnet Natural Gas	Bluebonnet Natural Gas	Cost of Service	Cost of Service/Rate Design
9797	Apr 08	Universal Natural Gas	Universal Natural Gas	Cost of Service	Cost of Service/Rate Design
9732	Jul 08	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9670	Oct 06	Cities Steering Committee	Atmos Energy Corp.	Cost of Service	Affiliate Transactions/ O&M Expenses/GRIP
9667	Nov 06	Oneok Westex Transmission	Oneok Westex Transmission	Abandonment	Abandonment
9598	Sep 05	Cities Steering Committee	Atmos Energy Corp.	GRIP Appeal	GRIP Calculation
9530	Apr 05	Cities Steering Committee	Atmos Energy Corp.	Gas Cost Review	Natural Gas Costs
9400	Dec 03	Cities Steering Committee	TXU Gas Company	Cost of Service	Affiliate Transactions/ O&M Expenses/Capital Costs

DKT NO.	DATE	REPRESENTING	UTILITY	PHASE	ISSUES
Before the Louisiana Public Service Commission					
U-37392	Feb 25	PSC Staff	Dixie Electric Membership Corporation	Cost of Service	Cost of Service / FRP Renewal
U-36254	Jul 22	PSC Staff	Dixie Electric Membership Corporation	Formula Rate Plan	Emergency Rate Relief
U-35359	Feb 20 Nov 20	PSC Staff	Dixie Electric Membership Corporation	Cost of Service	Cost of Service / FRP Renewal / AMS Certification Stipulation
U-34344/ U-34717	Apr 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Stipulation
U-34344	Jan 18	PSC Staff	Dixie Electric Member Corporation	Formula Rate Plan	Adjusted Revenues
U-33633	Nov 15	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Prudence
U-33033	Jul 14	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Revenue Requirement
U-31971	Nov 11	PSC Staff Entergy Gulf States Louisiana	Entergy Louisiana, LLC/	Resource Certification	Certification/Cost Recovery
Before the Colorado Public Utilities Commission					
18A-0791E	Mar 19	Pueblo County	Black Hills Colorado Electric	Economic Development Rate	Tariff Issues
Before the Arkansas Public Service Commission					
O7-105-U	Mar 08	Arkansas Customers & pipelines serving CenterPoint	CenterPoint Energy, Inc.	Gas Cost Complaint	Prudence / Cost Recovery

SOAH DOCKET NO. 473-25-09020
PUC DOCKET NO. 57463

APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR APPROVAL OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM RESILIENCY PLAN	§ § § § §	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND ATTACHMENTS

OF KARL J. NALEPA

Attachment KJN-3

QUESTION NO. TIEC 1-2:

For each of the proposed measures, please state the amount of capital and operations and maintenance (O&M) that SPS is proposing to invest in (1) the transmission system and (2) the distribution system.

RESPONSE:

Please see Exhibit SPS-TIEC 1-2 Functionalization of Capital and O&M by Measure, which can be found on SPS's file sharing platform. For each proposed measure, Exhibit SPS-TIEC 1-2 presents the estimated Transmission, Distribution, and General functional classifications for capital and O&M. Please note that actual accounting under the FERC Uniform System of Accounts may differ based on actual asset classification at the time they are placed in-service and unitized in SPS's accounting records. At this time, SPS can only provide an estimate of functionalization between Distribution, Transmission, and General. This estimate requires numerous assumptions regarding, among other things, the total costs of SPS's approved SRP and the timing of capital investments and O&M activities.

Preparers: Brianne Jole, Wendall Reimer, Anne Sherwood, Richard Lain
Sponsors: Brianne Jole, Wendall Reimer, Anne Sherwood, Brooke Trammell

QUESTION NO. TIEC 1-3:

Please provide the projected TCRF and DCRF rate impact by customer class assuming all cost recovery occurs at the same time (no need to spread across multiple years) from the proposed SRP, along with supporting workpapers in "live" EXCEL format.

RESPONSE:

At this time, SPS can only provide an estimate of the rate impact by customer class for SPS's projected TCRF and DCRF. This estimate requires numerous assumptions regarding, among other things, the total costs of SPS's approved System Resiliency Plan ("SRP"), the timing of capital investments and O&M activities; any related asset retirements; the timing of DCRF and TCRF rate filings; the amortization of SRP cost deferrals; the applicable deferred income tax benefits; the effects of subsequent changes in the components of the costs of capital, future usage, and customer growth; and numerous other factors. Changes to any of these assumptions between now and year-end 2028 will affect the actual rate impacts for SPS customers.

To estimate the SRP rate impact, SPS developed a capital revenue requirement factor consisting of its approved Weighted Average Cost of Capital, income tax gross-up, approved depreciation rates, and taxes (other than income taxes). SPS also developed a revenue requirement factor for distribution O&M that will be included in cost deferrals and included in a subsequent DCRF or base rate filing. SPS applied the capital revenue requirement factor to the total estimated capital expenditures proposed in this filing.

The resulting estimate is presented as an annual percentage bill increase from today's rates, by customer class, for the DCRF and TCRF in Exhibit SPS-TIEC 1-3 - SRP Rate and Bill Impacts.xlsx, which can be found on SPS's file sharing platform.

Preparers: Richard Lain, Alex Trowbridge
Sponsor: Brooke Trammell

QUESTION NO. TIEC 2-5:

Referring to page 38, please provide a list of each project and its associated capital investment over the last 5 years under the Advanced Capital Projects Initiative. In responding, please identify which projects are hardening and transmission related.

RESPONSE:

The Advanced Capital Projects Initiative was formalized in 2021 to standardize the intake of projects that previously were completed following a local review for Distribution specific projects; none of the projects are Transmission related. The list in Exhibit SPS-TIEC 2-5 is not all inclusive of projects that SPS completes to support our communities but captures the projects associated with the Advanced Capital Projects Initiative.

Preparers: Eran Moore, Brianne Jole
Sponsor: Casey Meeks

QUESTION NO. TIEC 2-12:

Referring to page 81 and mobile substations:

a. Please provide a list of SPS's existing inventory of mobile substations, including size/voltage/configuration details, along with asset age.
b. Please provide in "live" Excel format the O&M expense for the past 5 years for the existing mobile substation fleet.
c. What is the estimated annual ongoing O&M expense to operate and maintain the mobile substations being requested in this SRP?
d. How are mobile substations currently functionalized?

RESPONSE:

a. See below for the list of mobile substations/equipment currently in the SPS fleet, including mobile substations currently on order.

SPS MOBILE SUBSTATIONS

Unit	MVA	HV Ratings (kV)	LV Ratings (kV)	Manufc. Year	Age
Z501	20	117D x 67D	34.5Y x 24.94Y x 12.47Y x 4.16Y	2016	9
Z502	20	115/69	23Y x 13.2Y	1979	46
Z503	10	67D x 34.5D x 23D	12.47Y x 7.2D x 4.16Y x 2.4D	1971	54
Z504	28	117D x 67D	34.5Y x 24.94Y x 12.47Y	2011	14
Z505	56	115	69	2014	11
Z506	28	117D x 67D	34.5Y x 24.94Y x 12.47Y	2012	13
Z509	20	117D x 67D	24.94Y x 12.47Y x 4.16Y	1992	33
Z512	28	117D x 69D	34.5Y x 24.94Y x 12.47Y	2019	6
Z513	28	117D x 69D	34.5Y x 24.94Y x 12.47Y	2020	5
Z514	30	138D x 115D x 69D	12.47Y	2015	10
Z515	14.4	67D x 34.5D x 23D	13.2Y x 4.16Y x 2.4D	2021	4
Z516	14.4	69 x 34.5 x 23	13.2Y x 4.16Y x 2.4D	2022	3
	20	117D x 69D	23Y x 13.2Y	2019	6

SPS MOBILE SUBSTATIONS - On Order

Unit	MVA	HV Ratings (kV)	LV Ratings (kV)	Manufc. Year	Age
	70	115	69	2025	0
	20	117D x 67D	24.94Y x 12.47Y	2025	0
	28	117D x 67D	34.5Y x 24.94Y x 12.47Y	2025	0

	28	117D x 67D	34.5Y x 24.94Y x 12.47Y	2025	0

SPS MOBILE EQUIPMENT

Unit	DESCRIPTION	HV Ratings (kV)	LV Ratings (kV)	Manufc. Year	Age
Z507	20 MVA Regulator Trailer	12.5Y	12.5Y	1992	33
Z511	115 kV Circuit Switcher	115Y	115Y	1992	33

b. SPS does not maintain this data in the requested format. The O&M expense for mobile substation equipment is $36 per month. For 15 mobile substations/equipment, that equates to $6480 per year in O&M costs.

c. See Table 16 in the SRP (Bates 103). All O&M costs reported for the Operational Flexibility measure relate to the Mobile Substation Equipment Procurement program. On-going O&M would be similar to existing units at $36 per month, per unit.

d. Unit Z505 is functionalized to transmission. All other mobile substations are functionalized to distribution. Because all units are stored in Amarillo, TX, all costs are functionalized to Texas and charged to New Mexico customers only if and when they are utilized in New Mexico.

Preparer: Joel Brown
Sponsor: Brianne Jole

QUESTION NO. TIEC 2-22:

Referring to page 20:

a. Does a BCR of 0.9 mean that the customer only recoups 90% of its investment over the life of the investment? If anything other than yes, please explain.

b. Did 1898 & Co. rely on any reports, surveys, or other data in determining that general safety risk and other qualitative considerations provided an additional 10% customer benefit recommended for each of the various types of programs and measures proposed? If yes, please provide the reports, surveys, or other data relied upon.

RESPONSE:

a. No. A BCR of 0.9 means that the benefits quantified by 1898 & Co., when monetized using the DOE ICE Calculator, equal 90% of the net present value of the cost of the investment over its lifetime. As noted in the 1898 & Co. Report, other qualitative considerations that provide benefits to customers were not quantified, monetized, or included in the BCR calculation.

b. No. The 10% qualitative consideration is based on 1898 & Co.'s professional expertise, experience performing risk and resiliency modeling, and understanding of the risks associated with failed electric utility infrastructure. Mitigating safety, wildfire, and cybersecurity risks, improving overall service reliability, and other qualitative considerations provide real, tangible benefits for customers.

Preparers: Jason De Stigter, Jack Perkins
Sponsor: Jason De Stigter

The following requests pertain to the Direct Testimony of Brianne R. Jole:

QUESTION NO. TIEC 2-35:

Referring to page 40, lines 3-6, what will be the number of mobile substations, net of retirements, after SPS receives the four mobile substations on order right now?

RESPONSE:

SPS currently does not plan to retire assets while they are still functional. The proposed additions will allow SPS to retire older units as they fail.

Preparer: Joel Brown
Sponsor: Brianne Jole

QUESTION NO. TIEC 2-37:

Has SPS ever experienced a resiliency event situation where all of its mobile substations were deployed and it would have benefitted from additional mobile substations? If yes, please describe the resiliency event and provide relevant information that substantiates that additional mobile substations would have provided incremental benefit.

RESPONSE:

SPS has never experienced a single resiliency event that required every mobile substation in the fleet to be deployed in response.

Preparer: Joel Brown
Sponsor: Brianne Jole

Project No. 41381

Southwestern Public Service Company (SPS)
d/b/a Xcel Energy

Annual Report on Vegetation Management
As Required by 16 Tex. Admin. Code §25.96
To the
Public Utility Commission of Texas (PUCT)

May 1, 2024

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SOUTHWESTERN PUBLIC SERVICE COMPANY

VEGETATION MANAGEMENT REPORT – 2024

TABLE OF CONTENTS

Contents

Vegetation Management Plan Summary for 2024

Overview

Southwestern Public Service Company's ("SPS") Vegetation Management department performs functions associated with regulatory compliance, electric service reliability and safety of SPS's electric distribution and transmission overhead lines, substations, and other facilities through the management of vegetation[1]. SPS's Vegetation Management Program includes the services of distribution and transmission line clearance, overhead safety inspection program, landscape maintenance, and bare ground weed control.

This Vegetation Management Report ("Report") summarizes SPS's Vegetation Management Plan ("Plan") for 2024 and the Vegetation Management Implementation Summary for 2023 as prescribed in the Public Utility Commission of Texas ("PUCT") Electric Rules, SUBST. R. 25.96., pursuant to §25.96(f).

Background

SPS implemented a formal transmission and distribution vegetation management program in 1999. The objective of SPS's Vegetation Management Program is to keep primary-voltage conductors clear of incompatible vegetation. This is primarily accomplished by outside contractors performing routine maintenance. Maintenance activities include tree and brush mitigation/removal, tree pruning, mowing, and herbicide applications. Maintenance objectives include:

- Public and worker safety
- Compliance with regulatory requirements
- Reliable electric service
- Integrated vegetation management practices
- Environmental stewardship and habitat enhancement

A professional vegetation manager is employed to oversee the program. The current SPS Vegetation Management Program Manager is a licensed Texas pesticide applicator as well as an ISA Certified Arborist. Continuing Education Units (CEUs) are required to maintain each of these certifications.

Contractors perform most field work. Each year, contractors are assigned a list of circuits/maintenance maps to be worked. After the contractor completes a circuit or map, SPS inspects the work for compliance in accordance with Xcel Energy's Vegetation Management Guidelines, attached to this report as Appendix A.

Customer Education

SPS has several publications related to vegetation management that are shared with customers. These include practical manuals on topics like tree pruning and planting as well as several types of door hangers for customer identification and acknowledgement. Customers are notified of scheduled work by an outbound

[1] SPS is an electric utility subsidiary of Xcel Energy Inc. ("Xcel Energy"). Xcel Energy is the parent company of the following four wholly owned utility operating companies: Northern States Power Company, a Minnesota corporation ("NSPM"); Northern States Power Company, a Wisconsin corporation ("NSPW"); Public Service Company of Colorado, a Colorado corporation ("PSCo"); and SPS.

call recording, door hanger or personal visit. Additionally, all customer materials are available on Xcel Energy's website at: https://www.xcelenergy.com/trees

A. VEGETATION MANAGEMENT GOALS

The overall goal of SPS's Vegetation Management Program is to develop site-specific, environmentally sensitive, cost-effective, and socially responsible solutions to vegetation control near electric facilities. We do this through risk-based scheduling of distribution facilities. This risk-based analysis considers past outages, customer counts, and other risk factors, which allows SPS to best manage potential reliability impacts, like System Average Interruption Duration Index ("SAIDI") metrics. While SPS's cyclical interval base is five years, some distribution circuits are scheduled for vegetation management activities after three to four years, while others may be scheduled after six to seven years, based on the results of risk analysis.

Due to the wide range of vegetation types and densities found throughout the service territory in Texas, the number of miles of distribution facilities needed to be addressed varies greatly from year to year as does the corresponding level of expenditures.

SPS tracks the following information monthly: (1) number of distribution miles completed; (2) cost per mile completed; (3) expense amount; (4) number of sustained customer interruptions due to vegetation (normalized and non-normalized); (5) contractor completed work evaluations; and (6) contractor safety-related incidents.

More information related to SPS's Vegetation Management Program goals can be found in Section 1 and 2 of Xcel Energy's Vegetation Management Guidelines (Appendix A).

B. VEGETATION CLEARANCES AND SCHEDULING APPROACH

As detailed in Section 3 of Xcel Energy's Vegetation Management Guidelines (Appendix A), SPS distribution clearance guidelines trees which have shown prior contact with energized facilities and/or appear to have a likelihood of growing beyond the conductors prior to the following maintenance cycle shall be pruned to provide a minimum of six (6) feet of side clearance from the outermost phase, and a minimum of ten (10) feet of clearance from below the wires at time of maintenance pruning.

C. REMEDIATION PLAN

Identification of Vegetation-Caused Outages

As part of SPS's Vegetation Management Program, vegetation-caused, primary level voltage outages that impact more than 25 customers are investigated soon after the event to determine if the event was preventable or non-preventable. An example of a preventable vegetation-caused event would be re-growth of a tree from the last maintenance cycle breaking and falling across a line causing an outage. An example of a non-preventable vegetation-caused outage would be a tree with no obvious defects uprooting from outside the right-of-way. These investigations prove very helpful in determining the effectiveness of SPS's Vegetation Management Program and help SPS personnel customize the program to meet specific vegetation management risks by area.

2023 Top Ten Percent SAIDI and SAIFI Feeders

Appendix B includes the 2024 Remediation plan for the 2023 top ten percent SAIDI and System Average Interruption Frequency Index ("SAIFI") feeders, affected by vegetation-caused events only. The 2023 top ten percent distribution feeders for the SAIDI and SAIFI include 17 total circuits after accounting for duplicates between the two lists. Appendix B indicates the SAIDI and SAIFI values, number of events, customer minutes out ("CMO") and sustained customer interruptions ("SCI") count, the number of SCI's investigated by the vegetation management department, the number of preventable and non-preventable SCIs as determined by the vegetation management department, the last year vegetation maintenance was performed, the year vegetation maintenance is scheduled, and the remediation plan for each feeder.

Analysis

- Nine feeders are scheduled for inspection in 2024 for critical tree issues.
- Eight of the feeders had minor vegetation-caused events. No remediation plan is needed.

Conclusions

The 2023 top ten percent SAIDI and SAIFI feeder list, affected by vegetation-caused events only, does not indicate any feeders that are having significant, repeated, preventable vegetation events. The reasons for relatively low vegetation impacts include program oversight promoting proper pruning techniques, adequate clearance at the time of pruning, pursuance of tree removals and brush control, and the inspection of completed work.

D. TREE RISK MANAGEMENT PROGRAM

Trees are a major contributor of electric service interruptions nationwide. Trees cause outages in two ways, mechanical and electrical. Mechanical damage refers to entire trees or portions of trees failing and physically damaging facilities (knocking down wires, poles, etc.). Electrical outages can also occur. These interruptions are caused when a portion of a tree becomes a short-circuit path for electricity causing a protective device to operate and stop the flow of electricity. Section 2 of Xcel Energy's Vegetation Management Guidelines (Appendix A) details SPS's tree risk management program.

Hazard Tree Mitigation

Any tree on or off the right-of-way with the potential to contact an electric supply line is considered a "danger tree". A "hazard tree" is a tree that has an unacceptable risk of failing before the next maintenance cycle. Hazard trees are cleared below line height or removed.

Conditions which may indicate presence of a "hazard tree" include but are not limited to the following:

- Biological Factors
    - Decay/deadwood/dead trees
    - Cracks

  - Weak branch unions
  - Cankers/fungal bodies

- Environmental Factors
  - Root damage, restrictions
  - Changes in exposure
  - Poor architecture (leaning, structural overloading, imbalance due to wounding, etc.)

Work Guidelines

The American National Standard Institute's A-300 standard presents performance standards for the care and maintenance of trees, shrubs, and other woody plants. The standard is intended as a guide for federal, state, municipal, and private authorities including property owners, property managers, and utilities.

Tree pruning is the selective removal of branches within inadequate distance from the primary line, or that will grow too close to the power line before the next maintenance cycle. Secondary, streetlight and service wires are not routinely pruned for clearance unless overbuilt primary exists. Secondary or streetlight wires are generally cleared of vegetation if major interference, such as a broken limb, exists.

Tree pruning is done to provide adequate clearance from SPS facilities while making proper cuts. If practical, pruning methods will be based on procedures and examples set forth by ANSI A300. Generally, trees are pruned to improve or re-establish the clearance provided from previous tree maintenance performed.

Dangerous limbs, such as those overhanging wires having a high potential risk for breaking or bending into SPS conductors due to ice, snow or wind loading are removed or shortened.

Tree Removal

Tree removal is the selective mitigation of entire trees and brush at ground level. Generally, SPS will mitigate (or in the case of brush, remove):

- Tall-growing trees fitting the mitigation criteria for the geographic region
- Tall-growing brush having the potential to grow into the conductor
- All second growth from stumps cut on previous pruning cycles

All trees and brush are cut as close to the ground as practical, and attempts are made to treat all deciduous stumps with approved herbicide to prevent sprouting. Trees are not routinely removed from the vicinity of secondary, streetlight and service wires. Customers wanting to have trees removed near these conductors on their own may request the conductor be de-energized by SPS for private tree mitigation.

E. ADVERSE ENVIRONMENTAL CONDITIONS

SPS monitors adverse environmental conditions, such as drought and wildfire danger, through news reports, local and regional weather warnings, the Texas Forest Service and from internal field inspections. In the event of such adverse environmental conditions, SPS employees, crews and contractors are prepared to respond quickly to such conditions to maintain the reliability of the system and safely restore power if an outage occurs while minimizing the impact on vegetation on the electric distribution system. Finally, SPS vegetation management personnel and contractors are trained to identify trees that have become or are becoming hazard trees due to drought conditions.

F. OVERHEAD DISTRIBUTION MILES

Table 1 below shows SPS's total overhead primary voltage distribution miles in its Texas system, excluding service drops as of January 1, 2024.

Table 1 – Total Overhead Circuit Primary Miles

Texas System	10,951

G. ELECTRIC POINTS OF DELIVERY

Table 2 below shows SPS's total number of distribution electric points of delivery on its Texas system as of January 1, 2024.

Table 2 - Total Number of Electric Points of Delivery

Texas System	267,178

H. AMOUNT OF VEGETATION-RELATED WORK

In 2024, approximately 1,098 distribution line miles are scheduled for maintenance. As of March 31, 2024, SPS has completed 536 miles of vegetation-related work, or approximately 48 percent. SPS's goal for the 2024 program year is to have approximately 71% of the distribution system on a five-year vegetation maintenance cycle by year end.

VEGETATION MANAGEMENT REPORT – 2024

I. BUDGET

Table 3 summarizes SPS's 2024 Vegetation Management budget. This budget covers calendar year 2024.

Table 3 – SPS's 2024 Vegetation Management Budget

Categories	**TX Contractor Amount**
Scheduled Vegetation Maintenance	$ 1,960,818
Unscheduled Vegetation Maintenance	$ 177,000
Tree Risk Management*	$ 0
Minor Emergency and Post-storm Activities*	$ 0
Total	**$ 2,137,818**

**Note:* Budgeted Tree Risk Management expenses are included in the Scheduled and Unscheduled Vegetation Management budget categories for 2024. Similarly, Minor Emergency and Post-storm Activity expenses are included in the Unscheduled Maintenance budget categories for 2024. Major Emergency and Post-storm Activity expenses including facility damage are typically charged to SPS storm reserve accounts.

Vegetation Management - Implementation Summary For 2023

A. VEGETATION MANAGEMENT GOALS

The following is a summary of the 2023 goals & results:

- SPS's vegetation management contractor successfully met all safety related goals with zero contractor-caused outages and no significant contract tree worker injuries.
- The Company also successfully met vegetation-caused outage goals, as measured by Sustained Customer Interrupts, with the weather normalized actual of 3,249 versus a year-end target of less than 4,615 customer interrupts.
- In 2023, SPS did not complete the initially planned target of 2,317 miles and completed miles were approximately 1,366 miles. The miles completed represented a higher average reliability risk value and were prioritized in 2023.
- SPS's 2024 plan has been developed based on reliability risk assessments performed for various maintenance areas as well as consideration of cycle status. Maintenance areas with higher reliability risks identified are scheduled for vegetation management activities in 2024.

B. SUCCESSES AND CHALLENGES

In 2023, SPS did not have any significant property owner interference issues. In situations where a property owner initially refuses access to perform the necessary vegetation clearing, SPS was able to resolve by following the established policy sending the property owner a certified letter stating the need to maintain their trees along with a date that the work has been scheduled.

C. PROGRESS AND OBSTACLES

In 2023, the remediation plan for all sixteen feeders was completed. Refer to the "2023 Texas Remediation Plan for 2022 Top 10% SAIFI & SAIDI Feeders" report (Appendix D). There were no obstacles.

D. CONTINUING EDUCATION HOURS

In 2023, the SPS Vegetation Management Program Manager certified by the Texas Department of Agriculture received the five CEU's need to recertify in January 2024 for the Texas pesticide applicator license. Eight (16.5) CEUs for the ISA Certified Arborists certification were obtained in 2023. ISA recertification is not due until June 2025.

E. VEGETATION MANAGEMENT WORK ACCOMPLISHED

In 2023, 1,366 distribution miles were completed. The goal at the beginning of the year was 2,317 miles.

F. SAIDI AND SAIFI SCORES

The separate SAIDI and SAIFI scores for vegetation-caused interruptions for each month by feeder are detailed in the 2023 TX Vegetation Annual Filing Feeder SAIDI SAIFI report (Appendix C1 & C2).

G. 2023 VEGETATION MANAGEMENT BUDGET VS ACTUAL

	2023 Budget (Contractor Only)	2023 Actual Expenditures (Contractor Only)	2023 Percentage of Actual Expenditures vs. Budget	Actual Expenditures for Preceding Year (2022) (Contractor Only)
Scheduled Work	$3,650,690	$1,587,929	43%	$2,039,155
Unscheduled Work	$133,975	$118,684	89%	$140,000
TOTAL	**$3,784,665**	**$1,706,613**	**45%**	**$2,179,155**

The actual expenditures for the 2023 targeted work were $1,493,802 versus a budgeted amount of $3,787,665. While the Company did not achieve the originally targeted miles cleared, the electric reliability of our Texas customers was not materially impacted as referenced in part A above.

TX 2023 Actual Expenditures Divided by Distribution Electric Points of Delivery (267,178)	$5.59
TX 2023 Actual Expenditures including Storm Reserve (+$76,293) Divided by the Number of Customers (267,178)	$5.88
SPS Distribution Vegetation Management Budget from Last Base Rate Case, January 1, 2022 through December 31, 2022	$2,397,565

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Appendix A – Xcel Energy's Vegetation Management Guidelines

VEGETATION MANAGEMENT PROGRAM

GUIDELINES

Xcel Energy®

TABLE OF CONTENTS

SECTION 1:
GENERAL

1.1 INTRODUCTION

Xcel Energy provides, safe, clean and reliable services to its customers at a competitive price. Xcel Energy (the Company) has developed these vegetation maintenance guidelines (Guidelines) for Company employees and contractors to use when performing vegetation maintenance services on electric distribution and transmission. These Guidelines are designed to help ensure that vegetation near our transmission and distribution facilities is maintained in a consistent manner that minimizes the risk of interference with the safe operation of the electric facilities. Vegetation management includes the services of electric distribution and transmission line clearance, overhead safety inspection program, landscape maintenance, bareground weed abatement and selected natural gas facilities.

These Guidelines are available in English and Spanish. Any interpretation of these Guidelines shall be based on the English version.

Additionally, Vegetation Management has standardized distribution and transmission business process maps. Contractors are required to comply with the most current versions.

Required documentation: Contractors who are performing vegetation management services are required to maintain and provide to their employees and keep on each truck or work location at all times:

- Current copy of the Guidelines.
- The booklet "Best Management Practices for Utility Pruning of Trees" by the International Society of Arboriculture.
- **Minimum approach distance tables to energized facilities.**

**This information supersedes all previous manuals and guidelines for line clearance and vegetation management work for Xcel Energy operating companies including Northern States Power Minnesota, Northern States Power Wisconsin, Public Service Company of Colorado, and Southwestern Public Service Company, whether one or more, each is referred to as "Company" herein.

The Vegetation Management Program Guidelines was developed by the Company for use by Company employees and its authorized representatives based on its work practices, safety rules, training, appropriate governing authorities and rules, as well as weather, topography and historic methods. Use of this manual by unauthorized third parties is not permitted and may result in damage or injury due to conditions unique to the Company for which the manual was developed. This manual and the information it contains are the sole Property of the Company and are considered confidential. No part of this book will be distributed to any party without permission from the Company.

1.2 SAFETY POLICY

1.2.1 General

All personnel performing vegetation management work on or near Company facilities or rights of way shall follow approved safety guidelines and procedures. All contractors performing work for the Company shall comply with all applicable governmental safety and health regulations, and the safety and health provisions of their contracts. Unless superseded by Company safety policy, contractors are responsible for developing and following their own safety procedures and complying with all laws and regulations.

Note: This information addresses reliability for the Company's operating companies and is not intended for use as personal safety guidelines. Regardless of the service performed, every work site has its own safety and work requirements.

1.2.2 Safety Intervention Stop Work Responsibility (SISWR)

Safety Statement

There is no job we do nor service we perform so urgent that we cannot take time and use the necessary equipment to do it safely.

The SISWR policy at the Company establishes each worker's authority and responsibility to perform a Safety Intervention or Stop Work when an unsafe condition or situation develops at their worksite. The simple message is, "If you see something unsafe, speak up and intervene. If the situation remains unsafe, stop the work." Everyone should feel confident to question and stop any at-risk behavior by Company employees, contractors, vendors, visitors or the general public, who may be in or around Company work sites.

Safety Intervention applies if there is no imminent danger or hazard to people. It should be utilized to resolve safety concerns or issues that can improve work practices, tools, and equipment, or to advance safety at the Company. To intervene, approach the individual and let the individual know you are concerned about the individual's safety. Take action to address or correct the unsafe situation. Then, get a commitment from the individual to work safely. If the issue is not resolved in a short period of time or if feedback provided is not acted upon, discuss the concern with the supervisor or manager. Safety interventions do not necessarily result in stopping work, but may elevate to stopping work if the issue is not quickly resolved.

Stop Work Responsibility: Every Company employee and contractor has both the authority and responsibility to stop work. Stop Work Responsibility is used to prevent injury, harm, or damage to Company employees, contractors, visitors, vendors, the general public, Company property and equipment, or the environment. To exercise Stop Work, safely stop the work, equipment, or process. Gather all personnel in the area and help identify the safety issues. Contact the person in charge, or a supervisor or manager, and let them know the work has been stopped and the resolution of an immediate safety concern is necessary.

1.2.3 Industry Standards

There are two important standards for tree worker safety in the United States, OSHA 1910.269[1] and ANSI Z133. Tree workers must meet the requirements of these standards as well as any other applicable federal, state or local laws, codes or regulations.

OSHA Standard 1910.269 is the Occupational Safety and Health Administration's vertical standard pertaining to work relating to the generation, transmission, and distribution of electricity. A specific section of OSHA 1910.269 requires that everyone performing tree work in proximity to electric hazards must be qualified and that their training is documented.

ANSI Z133 is the American National Standard for Arboricultural Operations – Pruning, Repairing, Maintaining, and Removing Trees, and Cutting Brush – Safety Requirements. ANSI Z133 provides information that can be helpful in understanding and complying with the requirements contained in OSHA Standard 1910.269.

ANSI Z133 defines an electric hazard to exist any time a tree worker, tool, tree or any other conductive object is closer than 10 feet from an energized conductor with a voltage of 50,000 volts or LESS, these clearance distances increase as voltages increase. ANSI Z133 provides tables that outline minimum approach distances for both qualified and non-qualified tree workers based on voltage and elevation. Contractors may elect to provide and train with minimum approach distance tables that have greater distances than outlined in ANSI Z133.

1.2.4 State Requirements

In the service territories of Public Service Company of Colorado and Southwestern Public Service Company, there are additional standards that apply.

Colorado: Colorado Revised Statutes Title 9 Safety – Industrial and Commercial, Article 2.5 - High Voltage Power lines – Safety Requirements. Only qualified employees of an electric utility can perform any activity that may bring an individual or equipment within 10 feet of high voltage (lines in excess of 600 volts) overhead lines. Contractors working directly for the utility are considered qualified. Non- qualified employees or individuals must contact the appropriate utility to make arrangements for safe activity.

Texas: Texas Statutes Chapter 752 – High Voltage Power lines. Only qualified employees of an electric utility can perform any activity that may bring an individual or equipment within 6 feet of high voltage (lines in excess of 600 volts) overhead lines. Contractors working directly for the utility are considered qualified. Non-qualified individuals must contact the appropriate utility to make arrangements for actions to be taken to mitigate the hazard.

[1]All references to Standards in these Guidelines refer to the most current published version of the standards at the time the Guidelines are being applied.

1.2.5 Additional Safety Considerations

The following safety procedures shall be followed by contractors performing vegetation management work for the Company:

- The contractors must be aware at all times of the nature and characteristics of the Company's electric and/or gas facilities to be worked before any work begins. Contractors need to understand that electric facilities must remain energized during the performance of work unless special arrangements are made with an authorized Company representative.
- The contractor shall comply with the Company's Contractor Safety Program.
- The contractor shall comply with the terms of its contract with the Company.
- The contractor shall obtain full information as to the voltage of its circuits and minimum approach distances before starting the work.
- The contractor shall at all times conduct work in a manner to safeguard the public from injury and property from damage.
- The contractor must use all necessary protection for its employees and the public, and guard against interference with normal operation of the circuits. If, in the judgment of the contractor's general foreperson/supervisor, it is too hazardous to prune or remove trees with the circuits energized, the contractor must contact an authorized Company representative(s). If appropriate, the Company will provide the necessary protective materials or de-energize circuits to ensure the safe pruning or removal of the tree(s).
- Should the contractor knock down or come into contact with Company conductors (power lines), the contractor must notify the Company immediately and take the necessary protective measures. All contractor-caused electric service interruptions are subject to repair at the contractor's expense.
- In the event a contractor becomes aware of any dangerous, broken, loose or faulty Company facilities in the normal course of its line clearance performance, the contractor shall promptly advise the Company as to the exact equipment location(s) and nature of the condition found in accordance with the Overhead Safety Inspection Program. (See Section 5)
- Any contractor personnel entering substation equipment yards must be qualified employees (OSHA 1910.269) and must have completed Company sponsored substation hazard awareness training. When instructed to do so, the contractor shall notify dispatch/area control prior to entering any substation and when leaving the substation. Contractors shall close the gate upon entering a substation and lock it upon exiting. Substation gates are to remain secured at all times in accordance with the Company's Substation Access Program. Parking in substations is not allowed unless pre-approved by the appropriate Company Vegetation Management representative.

1.3 WHY ELECTRIC UTILITIES ARE REQUIRED TO PERFORM VEGETATION MANAGEMENT

Trees are a major contributor of electric service interruptions nationwide. Trees cause outages in two ways; mechanical and electrical. Mechanical damage refers to entire trees or portions of trees failing and physically damaging facilities (knocking down wires, poles, etc.). Because trees can be conductive, electrical outages can also occur. These interruptions are caused when a portion of a tree becomes a short-circuit path for electricity. This often causes a protective device to operate and stop the flow of electricity. Vegetation management is necessary to ensure the safe and reliable operation of electric transmission and distribution facilities and, at the time of work, adequate vegetation clearance must be achieved from the conductors and mitigation of applicable hazard trees in an attempt to prevent interruptions of electric service for the duration of the targeted maintenance cycle.

The Company's vegetation management practices must comply with state and federal laws. These laws include requirements by state regulatory entities such as public utility commissions and public service commissions that require electric utilities to maintain their electrical systems in accordance with the National Electric Safety Code (NESC). The NESC generally requires the pruning or removal of interfering trees near overhead facilities. In addition, the NESC, Vegetation Management Section 218.A.1 addressed ungrounded facilities:

> *Vegetation that may damage ungrounded supply conductors should be pruned or removed. Vegetation management should be performed as experience has shown to be necessary.*
>
> *Note: Factors to consider in determining the extent of vegetation management required include, but are not limited to: line voltage class, species' growth rates and failure characteristics, the vegetation's location in relation to the conductors, the potential combined movement of vegetation and conductors during routine winds, and sagging of conductors due to elevated temperatures or icing.*

Federal law, through the North American Electric Reliability Corporation (NERC), imposes additional requirements on overhead transmission lines of 200kV or higher. See section 4.3.

SECTION 2:
SUSTAINABILITY – INTEGRATED VEGETATION MANAGEMENT (IVM)

2.1 GENERAL VISION

IVM is a data-driven, progressive system of information gathering utilized to best plan and complete work, including follow-up auditing, to better ensure the desired results are achieved. It involves the use of various types of vegetation management techniques including the removing, pruning and mowing of vegetation and the treatment of vegetation with herbicides. The overall goal of a utility IVM program is to develop compliant, site-specific, environmentally sensitive, cost-effective and socially responsible solutions to vegetation control near electric and natural gas facilities. Additionally, it is a goal to maintain or reduce overall workload on cycle maintenance projects over multiple cycles on each maintenance area through pruning clearance and removal decisions through the application of these various techniques.

2.2 TREE RISK ASSESSMENT AND MITIGATION

The contractor will perform a limited visual tree risk assessment associated with assigned capital or maintenance projects on company facilities. Company facilities include but are not limited to electric and gas substations, electric distribution and transmission infrastructure (including poles, wires, and associated hardware), communication sites, office and warehouse buildings and other company facilities designated by the Company's vegetation management representative.

A limited visual tree risk assessment is defined as a visual assessment from a defined perspective (such as, one-sided, ground based, vehicular, or from an aircraft) of an individual tree or population of trees, to assess the risk to specific targets from obvious defects or specified conditions (ANSI A300, Part 9 Tree Risk Assessment & Tree Failure). Tree(s) identified having a moderate to high probability of failure which pose an unacceptable risk will be mitigated. The Company defines a tree that poses an unacceptable risk of failing onto Company facilities as a hazard tree. The contractor is also expected to report trees identified that pose an unacceptable risk to Company facilities outside assigned capital or maintenance projects to the Company's vegetation management representative.

Tree conditions to consider during a visual tree risk assessment are not limited to the following:

Biological Factors

- Decay/deadwood/dead trees
- Cracks
- Weak branch unions
- Cankers/fungal bodies
- Poor architecture

Environmental Factors

- Root damage, restrictions
- Changes in exposure (e.g. newly exposed trees along the edge of the right of way)
- Slope/Grade

2.3 ANSI A-300

The American National Standard Institute's A-300 standard presents performance standards for the care and maintenance of trees, shrubs, and other woody plants. The standard is intended as a guide for federal, state, municipal, and private authorities including property owners, property managers and utilities.

Whenever practicable, contractor tree workers are expected to adhere to this standard when managing vegetation near electric facilities.

2.4 WORK DESCRIPTIONS

2.4.1 Pruning

Tree pruning is the selective removal of branches that pose an unacceptable safety or reliability risk to the conductors or equipment currently, based on evidence of prior tree contact, or that may pose an unacceptable safety or reliability risk before the next routine maintenance.

Maintenance cycles are targeted for each individual maintenance area as a guide for planning purposes. A maintenance area is a geographical area maintained by Vegetation Management, regardless of electrical connectivity. In most cases, the initial area was defined by the circuit schema that existed when the maintenance area was created and the maintenance area name is derived from this circuit name. If the maintenance cycle for the maintenance area being worked is not known, please contact the appropriate Company Vegetation Management representative.

Pruning methods will be based on procedures and examples set forth by ANSI A-300. Trees should be pruned to improve or re-establish the clearance provided from previous tree maintenance performed.

For more information regarding distribution pruning clearances, please see Section 3.2; for more information regarding transmission pruning clearances, please see Section 4.2.

2.4.2 Removal

Tree removal is the selective clearing of an entire tree at ground level.

For more information regarding distribution removal criteria, please see Section 3.2; for more information regarding transmission removal criteria, please see Section 4.2.

2.4.3 Pole Clearing

Clear vines from poles, generally this means cutting at both ground level and at least 6 feet up the pole. Treat base of vine with herbicide when possible. Leave remaining vines on conductors as they will quickly die and fall off. Never pull vines in proximity to energized conductor.

Clearing vegetation around distribution primary voltage poles and down guys to provide operational access should be performed during routine maintenance work whenever possible, especially poles with devices that need to be accessed by utility first responders. Additionally, specific pole clearing criteria may apply as part of wildfire risk mitigation programs; consult with your Vegetation Management representative for specific instructions.

2.4.4 Debris Disposal

Routine Maintenance – pruning and removing green trees

The contractor is responsible for determining the most responsible method for disposing of wood waste and debris. The contractor should notify the customer when more than 24-hours may pass before brush may be hauled away from a customer's property.

Distribution: Generally, brush is removed, the site is cleaned up and the large logs are cut into manageable-sized pieces and left on the property for the owner. Wood chips are sometimes blown on site in rural/wooded settings.

Transmission: Generally wood and brush are left on the right-of-way, either in whole pieces or mechanically masticated, especially in rural areas. Consult with Vegetation Management representative for additional information.

Reasoning: Trees are being worked solely because of the presence of power lines.

Storm/Emergency Response – clearing damaged trees in order to restore service

Debris created for emergency response work is left on site in a reasonably safe manner, and not hauled away.

Reasoning: The tree owner would be faced with the same clean-up if the power lines were not present and is benefitting from the Company's assistance.

New Construction/Rebuilds – clearing of vegetation for construction or facility upgrades or rebuilds associated with a capital job

Debris disposed of in accordance with negotiations with property owner.

Make Ready Work – typically private tree company requested work to clear trees a distance from the power line, so they can do more work for their customer.

The Company shall provide this service at its expense. Debris created is left on site in a reasonably safe manner, and not hauled away.

Reasoning: The customer's decision to work the tree is often independent of the presence of power lines. The tree is worked only to clear Company facilities so the customer can have their project completed.

Hazard Tree Mitigation – usually initiated by the Company during routine maintenance and mid-cycle programs, but sometimes initiated by private property owners as they attempt to comply with municipal ordinances regarding dead, dying or diseased trees

Debris created is left on site in a reasonably safe manner, and not hauled away.

Reasoning: The tree owner would be faced with the same clean-up if the power lines were not present and is benefitting from the Company's assistance by controlling the inevitable failure of the tree.

2.4.5 Other Methods Used

- Mechanical pruning
- Mechanical mowing
- Foliar herbicide spraying
- Cut-stubble herbicide spraying
- Pellet or granular herbicide applications
- Low volume basal herbicide applications
- Tree growth regulators

2.5 HERBICIDE GUIDELINES

All herbicide and treatment methods used by the contractor shall have prior approval by a Company Vegetation Management representative and shall comply with all easements, laws and regulations. Product labels and Safety Data Sheets (SDS) shall be provided upon request to the appropriate Company Vegetation Management representative.

2.5.1 Precautions

- Do not apply herbicides outside of right of way boundaries except in cases where landowner's written acknowledgement has been obtained.
- In Wisconsin, no herbicide will be used within or outside of the right-of-way for a transmission line designed for operation at 100 kV or above without the written consent of the landowner.
- If a property owner objects to any of the herbicide treatments, the operation shall immediately be discontinued on that property until any issues are resolved.
- Contractor should review state sensitivity registries prior to applications.

2.5.2 Spills or Accidents

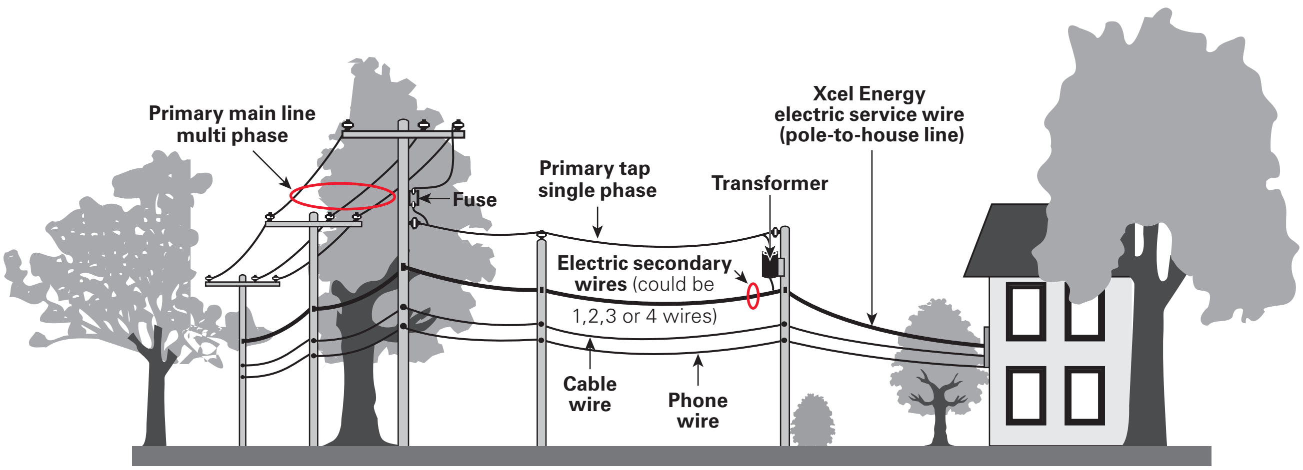
Any spill, leak, fire or other accident involving herbicides **must be reported immediately** to the appropriate Company Vegetation Management representative.

SECTION 3:
DISTRIBUTION VEGETATION MANAGEMENT

3.1 GENERAL GUIDELINES

Each individual tree needs to be assessed to determine adequate clearance beyond the defined minimums required from the conductor to prevent service interruption, damage to Company facilities, and threats to public safety. The Company expects qualified line-clearance contractors to use their professional judgment to determine what these clearances will be in each situation, based on the targeted maintenance cycle for the maintenance area on which they are working and the particular circumstances in the geographic area to minimize the risk that vegetation will interfere with the safe operation of the electric lines prior to the next maintenance cycle.

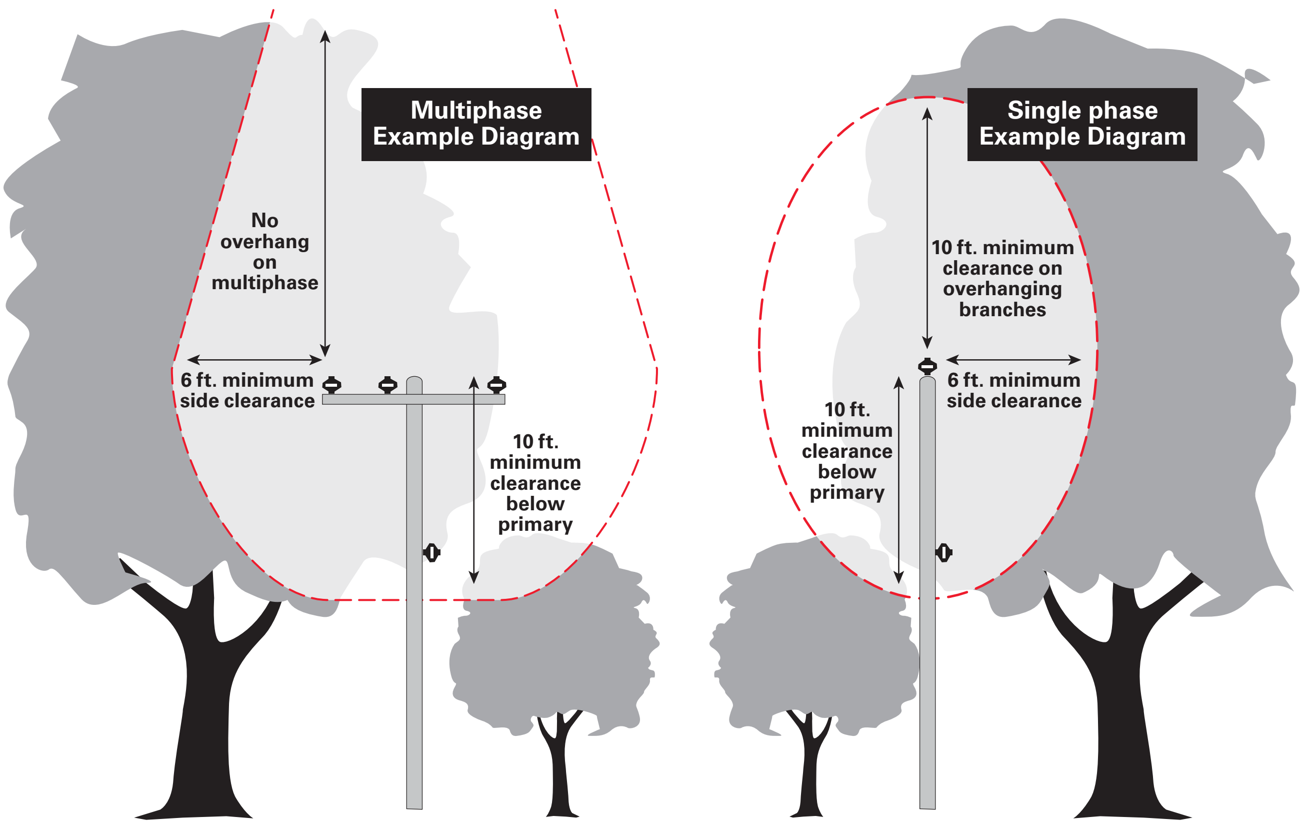
Contractors shall not rely on the accuracy of the distribution circuit or maintenance area maps. Instead, contractors are responsible for obtaining the appropriate clearances on all facilities existing in the field. The Company does not purposely clear non-company conductors including cable and phone wires.



3.2 VEGETATION-CONDUCTOR CLEARANCE AND OTHER CONSIDERATIONS

3.2.1 Clearance Minimums

Trees adjacent to all overhead primary voltage lines shall be evaluated for pruning or removal opportunities. Trees which have shown prior contact with energized facilities and/or appear to have a likelihood of growing beyond the conductors prior to the following maintenance cycle shall be pruned to provide a minimum of six (6) feet of side clearance from the outermost phase, and a minimum of ten (10) feet of clearance from below the wires at time of maintenance pruning. On multi-phase primary lines, no overhanging branches should be left above the conductors, on single-phase lines a minimum of ten (10) feet of overhead clearance should be achieved. Dead or visibly declining overhanging branches shall be removed from all overhead powerlines.



3.2.2 Minimum Clearance Exception Criteria

There may be scenarios where the minimum clearances cannot be achieved or pruning to those clearances does not provide a reliability benefit. See list of clearance exceptions below.

- Established leads greater than 4" in diameter that do not show signs of contact or growth into primary and do not appear to pose a public safety risk.
- Slow growing tree species that will not contact primary wires before the next targeted maintenance cycle.
- Span(s) which are scheduled to be rebuilt or relocated within the near future. Consult with your Vegetation Management representative on these locations.
- Overhang in healthy, fully forested settings, where removing overhanging limbs would create an opening in the forest canopy which may increase potential for limb failure (excludes wildfire risk zone areas).
- Contact the Vegetation Management representative for other exceptions not listed

3.2.3 Pruning Considerations:

- Overhanging branches should also be pruned off on all ash trees whenever possible, regardless of tree health.
- General public safety (existence of tree houses, climbable trees, public places, Risk of wildfire ignition, etc.)
- Based on the NESC, at line crossings, railroad crossings, limited-access highway crossings, or navigable waterways requiring crossing permits, the crossing span and the adjoining span on each side of the crossing should be kept free from overhanging or decayed trees or limbs that otherwise might fall into the line.
- When encountering primary voltage spans that appear to be deenergized, consult with your Vegetation Management representative.
- Also, when there is company-owned distribution underbuilt on transmission structures, vegetation selected for work shall also be maintained according to transmission specifications. Please contact your Vegetation Management representative for further direction.

Regardless of facility construction type, easily climbed trees (conifers in particular) shall be pruned to provide ground clearance and/or primary conductor clearance so that a person cannot easily access the primary conductor. Barriers to performing this work should be immediately reported to a Company Vegetation Management representative.

3.2.4 Removal Considerations:

- The contractor shall perform a limited visual inspection of each tree along the conductors of each maintenance area for tree removal opportunities and hazard tree mitigation (see Section 2.2) locations
- In general, target removal of tall-growing trees that can be removed on:
  - Multiphase – in no more than twice the pruning time.
  - Single phase – in the same time as would be necessary to prune.
- Remove tall-growing brush (<4” stem diameter) that has the potential to grow into the conductor.
- All trees and brush should be cut as close to the ground as practical.
- Whenever possible and authorized by state law, all deciduous stumps and areas mechanically mowed shall be treated with herbicide to prevent re-sprouting.

3.2.5 Large Tree Removals:

- The removal of any tree over 8-inches DBH within or outside the maintenance zone or corridor should be considered outside the fixed price bid or targeted price on hourly work.
  - The contractor shall track locations of and seek approval from their Vegetation Management representative for these trees or sites prior to performing the work.
  - The contractor and applicable Vegetation Management representative may also make determinations on tree removal criteria as part of joint inspection patrols before and while the project is actively being worked by crews.

3.2.6 Voltage Gradient

Voltage gradient (Vg) is a function of how electric facilities are constructed and can be a major factor in tree-caused outage risk. The higher the Vg, the greater the risk of an outage occurring when trees interfere with electric facilities. The Vg will vary based on construction types and operating voltage and can quickly be calculated in the field.

In multiphase situations, take the phase-to-phase voltage (kV) and divide it by the spacing between phases (feet). See Examples A, B & E.

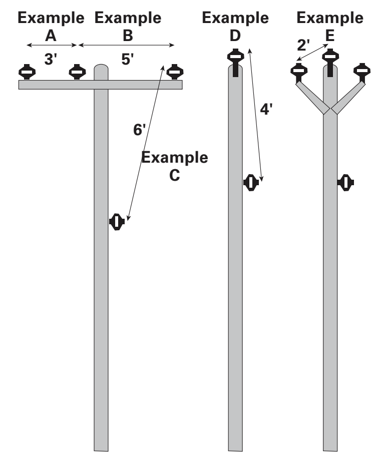
$$\mathbf{V_g \text{ for multi-phase}} = \frac{\textbf{phase to phase kV}}{\textbf{distance ft}}$$

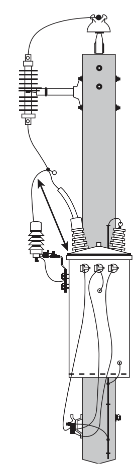
In single phase and multiphase situations where a branch might contact the phase and neutral, use the phase-to-ground voltage (kV) and divide by the distance between the phase and neutral (feet). See Examples C & D.

$$\mathbf{V_g \text{ for single-phase}} = \frac{\textbf{phase to ground kV}}{\textbf{distance ft}}$$

Bottom line: as voltage gradient increases, outage risk increases; higher operating voltage and/or shorter distance for a branch to bridge to cause a fault, the greater the risk. Work with your Vegetation Management representative to determine what Vg criteria to consider in your area. Within any Company-defined wildfire fire risk zone areas, voltage gradient factors shall not be considered.

VOLTAGE GRADIENT (VG) EXAMPLES		
Phase to Phase kV / Phase to Ground kV	**Voltage Gradient (kV/foot)**	**Risk**
	34.5 / 19.9	
Example A	12	High
Example B	7	High
Example C	3	Moderate
Example D	5	High
Example E	17	High
	13.8 / 8	
Example A	5	High
Example B	3	Moderate
Example C	1	Low
Example D	2	Low
Example E	4	High
	12.5 / 7.2	
Example A	4	High
Example B	3	Moderate
Example C	1	Low
Example D	2	Low
Example E	4	High
	4 / 2.3	
Example A	1	Low
Example B	1	Low
Example C	0.4	Low
Example D	1	Low
Example E	1	Low





Be mindful of extremely high Vg conditions where a branch may ground out between energized equipment and neutral or equipment housing (transformers, potheads, capacitor banks, etc.).

3.2.7 Secondary, Services, and Street Light Wires

These wires are to be cleared of broken limbs and to resolve significant wire deflection as part of routine maintenance activities. They are not typically pruned for a zone of clearance as part of routine maintenance unless overbuilt primary exists. If practical, ground personnel should prune trees interfering with secondary and service lines within the immediate area of the work site.

Trees are generally not removed from the vicinity of secondary, streetlight and service wires.

Additionally, specific secondary voltage clearing criteria may apply as part of wildfire risk mitigation programs; consult with your Vegetation Management representative for specific instructions.

3.3 TYPES OF DISTRIBUTION PROJECTS

3.3.1 Routine Maintenance / Scheduled Work

Routine Maintenance is proactive, scheduled work on a cyclical basis by maintenance area.

3.3.2 Mid-Cycle / Supplemental Inspection

Inspections that may be scheduled on selected maintenance areas for the purpose of identifying and mitigating as needed, vegetation conditions which, based on the criteria provided by the Vegetation Management representative, should be addressed prior to the next routine maintenance work. Projects will be assigned by the Vegetation Management representative.

3.3.3 Make Ready Clearance Requests

Only qualified line-clearance contractors, as defined by federal, state or local regulations or laws, can work on trees that have grown closer to power lines than certain distances as outlined in the applicable laws/regulations. Therefore, when requested, the Company (through its contractors) will provide preliminary clearance to help reduce the potential for electrical contact by third-party non-qualified workers. Requests for these clearances are known as "make ready" clearance requests.

It is important that contractor personnel respond to these requests in a prompt and timely manner and in accordance with any laws and regulations. Contractor personnel must also determine the most cost-effective course of action to provide make ready clearance. Examples include:

- Pruning the portion of the tree away from the conductor
- Dropping the tree on the ground
- Requesting that the conductor be de-energized
- If the request pertains to a service line, street light wire or other secondary line, advise the requesting party to call the Company's Customer Service at 800.895.4999 and request a "line drop" to temporarily remove the wire from the work zone. Service fees may apply for deenergizing or dropping these wires.
- Consult with your Vegetation Management representative for criteria when Make Ready clearing should occur for pole-to-pole secondary voltage spans.

As of the publication date, the Company does not currently charge a fee for the pruning or dropping of trees related to make ready clearance requests, but it is important that the contractor clearly communicate to the requesting party that all debris will be left on site. the Company may collect fees in the future.

3.3.4 Internal Reliability Related Requests

It is important that contractors respond to these requests in a timely manner and in accordance with any instructions provided with the request. We expect contractors to make a judgment call as to the necessity of pruning. Contractors need to consider all factors, including the likelihood of the tree to cause an outage in its current condition, risk to public safety, and when the tree is due for routine maintenance, when making this decision.

3.3.5 Construction / Cross Charge

These requests pertain to the installation of new facilities and the upgrade of existing facilities. In many cases contractor personnel will be asked to identify trees requiring clearance and to provide information that will be used to estimate the cost of tree clearing. It is important that contractor personnel respond to these requests in a prompt and timely manner and in accordance with any instructions provided with the request.

3.3.6 Emergency / Storm Response

Contractor personnel are required to respond to storm situations in accordance with the regional storm response process. Contact the Vegetation Management representative to confirm applicable regional processes. Only work necessary for the restoration of power will be performed. A reasonable attempt should be made to notify customers. No debris disposal will be attempted for any tree work performed.

3.3.7 Wildfire Risk Mitigation Programs

Programs may exist in some Company regions specific to lessening risk of wildfire ignition or consequence such as hazard tree mitigation programs, distribution pole clearing, pruning a zone of clearance for secondary voltages and approach to routine maintenance projects. Consult with your Vegetation Management representative for specific instructions.

Contractors shall at all times be aware of fire conditions and restrictions within the area(s) they operate. Contractors shall follow all required regulatory entity restrictions and control requirements. Compliance includes but is not limited to maintaining all necessary firefighting tools and equipment, all necessary fire and suppression training, required reporting, and stop work moratoriums should the governing jurisdictions or the Company determine unsafe working conditions exist.

SECTION 4:
TRANSMISSION VEGETATION MANAGEMENT

4.1 GENERAL GUIDELINES AND PROGRAM PHILOSOPHY

The primary objective of the transmission line clearance program is to keep transmission facilities clear of all incompatible trees, brush and other vegetation that could grow too close to conductors or otherwise interfere with the safe operation and maintenance of the facility. Incompatible vegetation is defined as vegetation that at maximum mature height could encroach within maintained clearance distances. This is accomplished by performing routine maintenance on each transmission maintenance area including tree felling, pruning, mowing and herbicide application.

4.2 ACHIEVING CLEARANCE AT THE TIME OF INITIAL CLEARING AND MAINTENANCE

4.2.1 Bramble and Byrnes

Wherever practical, the Wire Zone/Border Zone concept (Bramble and Byrnes) shall be integrated into the vegetation management program to allow for different types and heights of vegetation in the ROW. The International Society of Arboriculture's booklet titled "Best Management Practices – Integrated Vegetation Management" (a companion publication of ANSI A300, Part 7) provides a good working summary of this concept. This concept differentiates between the wire zone directly under the conductors, factoring in sway potential, and the remaining border zone.

Generally, this concept allows for different, yet compatible vegetation types in separate zones.

Wire Zone: Area directly underneath the conductor(s), including potential conductor sway. Vegetation in the wire zone consists of low- growing forbs and grasses.

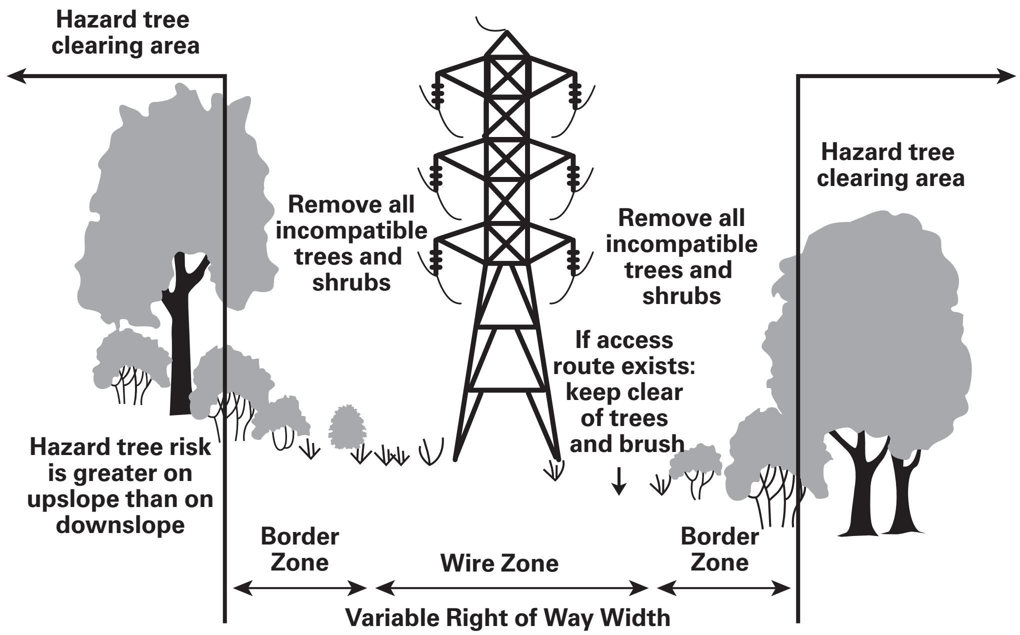
Border Zone: Area that begins at the outside edge of the wire zone and extends to the edge of the maintained ROW, easement or other right of way. The border zone may contain additional low-growing woody plants and trees. Trees that originate outside of the easement bounds yet have growth that has extends within the plane of the easement bounds should be evaluated for side pruning. Leaving low-grow woody vegetation in border zones may not be compatible in all areas due to construction type, narrower widths of easement & ROWs, accessibility requirements, ladder fuel concerns in wildfire risk zone areas, and other factors.

Areas outside the border zone must be patrolled for hazard trees (see Section 2.2).

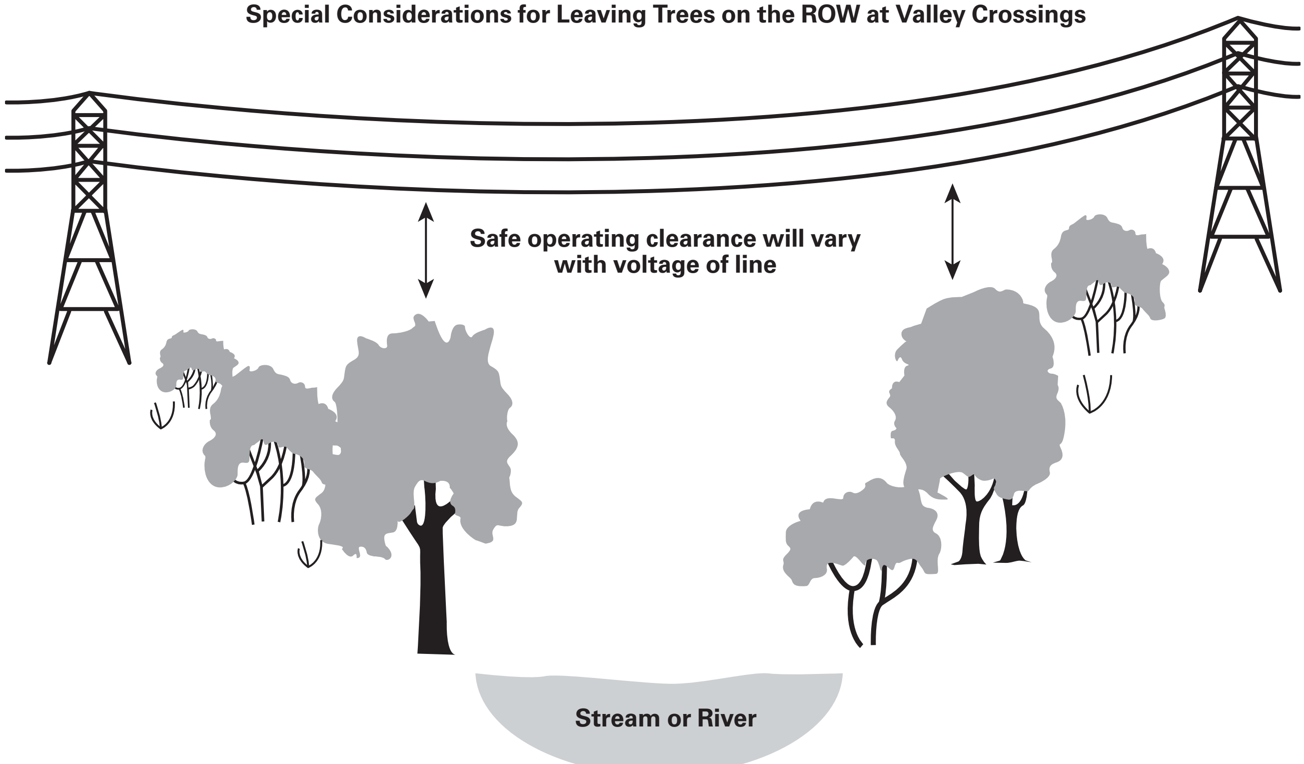
4.2.2 Other Considerations:

- Complete removal or control of incompatible vegetation on the ROW should always be the primary mitigation method before considering pruning.
- Mitigate obvious on-easement trees that pose a fall-in risk to the conductors. This includes trees that appear healthy and without visible defects.
- Remove tall-growing brush that has the potential to grow into the conductor.
- All trees and brush should be cut as close to the ground as practical.
- Remove all second growth from stumps cut on previous work projects.
- Whenever possible and authorized by state law, all deciduous stumps and areas mechanically mowed that may resprout shall be treated with herbicide to prevent re-sprouting.
- Mitigate all trees that present an unacceptable risk to Company facilities (see Section 2.2). The identification and mitigation of hazard trees should be a priority as mitigating these situations will greatly reduce the risk of preventable mechanical outages.
- Keep switch grates clear of all vegetation. Apply bare ground herbicide to switch grates whenever feasible.

Transmission Wire Zone/Border Zone ROW



Special Considerations for Leaving Trees on the ROW at Valley Crossings



4.2.3 Structure Clearing

Woody vegetation surrounding transmission structures shall be cleared as part of routine maintenance to better provide access to and to help protect the structure in the event of a passing wildfire. On projects within the Company's designated wildfire risk zones this clearing radius is 50-feet, or the entire easement/right of way agreement width, whichever is less. In addition, existing wood debris on the ground should be shifted away from the structure for at least a 15-feet radius on steel structures and 50-feet radius on wood and aluminum structures. In all other areas of the Company this radius is at least 10-feet.

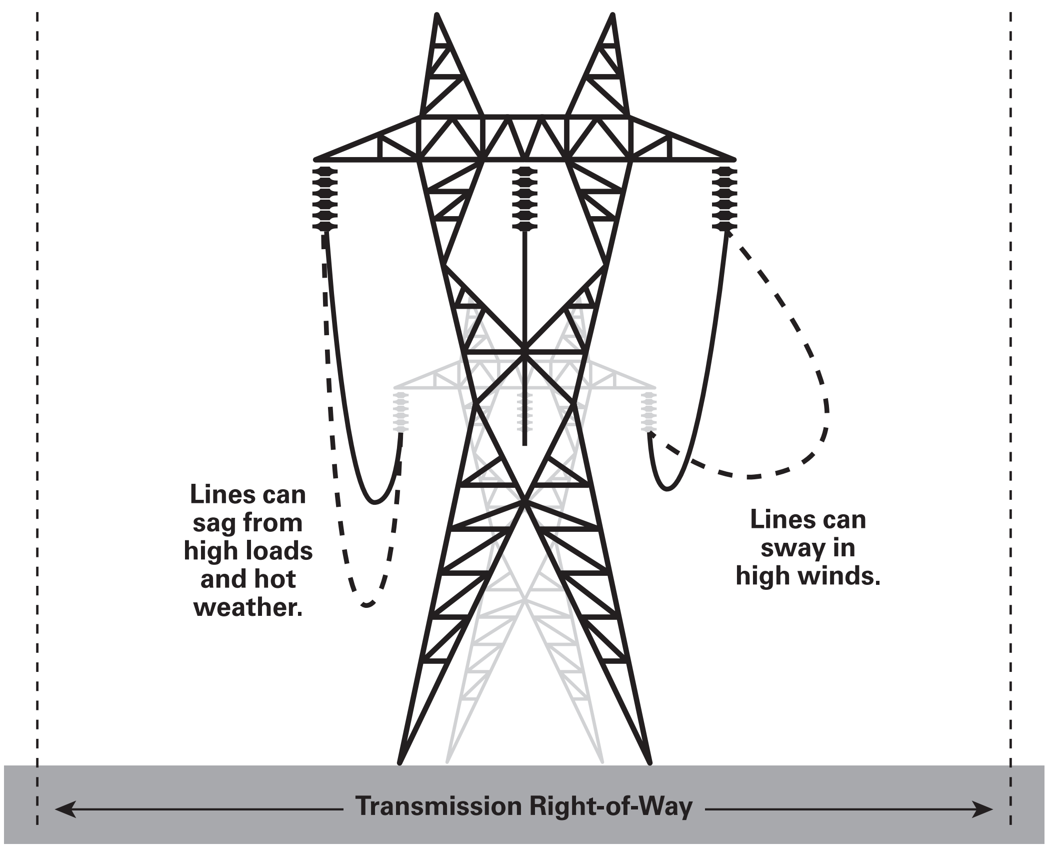
4.2.4 Maintained Clearances for Trees

TABLE A - MAINTAINED VEGETATION CLEARANCES AT STRUCTURE OR LOWEST SAG POINT/GREATEST SWAY POINT (FT) - ALL STATES, ALL ELEVATIONS

Voltage (kV)	At Structure		Up to 400 Ft Span		Up to 800 Ft Span		Up to 1,200 Ft Span	
	Horizontal ↔	Vertical ↕	Horizontal ↔	Vertical ↕	Horizontal ↔	Vertical ↕	Horizontal ↔	Vertical ↕
69	11	11	11	14	18	18	28	22
88	12	12	12	15	19	19	29	23
115	13	13	13	16	20	20	30	24
161	14	14	14	17	21	21	31	25
230	18	17	18	20	25	24	35	28
345	22	20	22	23	29	27	39	31
500	27	23	27	26	34	30	44	34

The following maintained vegetation guidelines clearances in Table A are to be maintained at all times, where easement rights allow. These clearances are provided at two points along the span for both horizontal and vertical clearance and indicate clearances at the structure and at the low point of the conductor (belly of the line). The differences in the clearance values in Table A are due to the sag/sway factor for varying span lengths and are intended to be applicable at any time of the year. Depending on where the tree is located, determine the best number to use from this table.

Additionally, here is a diagram that illustrates sag and sway of conductors.



4.2.5 Anticipated Tree Re-Growth

In order to maintain these clearances at all times, contractors performing tree work must consider multiple factors including the tree species, growing environment, re-growth rate, whether re-growth will be vertical or horizontal, elevation above sea level, and maintenance cycle length to determine the amount of clearance required at the time of pruning.

The following table is provided as a guideline only and the contractor is responsible for evaluating each situation. Each tree requires the evaluation of the above factors in order to determine specific re-growth rates. For species and maintenance cycles not listed, determine appropriate clearance based on the factors listed above.

TABLE 1: REGROWTH (ALL OPERATING AREAS)

Common Tree Species	Average re-growth after pruning (ft)	
	4 Year Cycle	5 Year Cycle
Willow (Salix spp)	14	16
Boxelder (Acer negundo)	13	15
Elms (Ulmus spp)	12	14
Tree of Heaven (Ailanthus spp)	12	14
Mulberry (Morus spp)	12	13
Osage Orange (Maclura pomifera)	12	13
Pecan (Carya spp)	12	13
Cottonwood, Aspen, Poplar (Populus spp)	11	12
Russian Olive (Elaeagnus angustifolia)	11	12
Linden, Basswood (Tilia spp)	10	12
Silver & soft maples (Acer sacharinum)	10	12
Ash (Fraxinus spp)	9	11
Black Walnut (Juglans spp)	8	10
Sugar & hard maples (Acer saccharum)	8	10
Oak (Quercus spp)	7	9
Locusts (Robinia spp & Gleditsia spp)	7	8
Conifers: Spruce (Picea spp), Pine (Pinus spp), Fir (Abies spp & Psuedotsuga spp)	5	6

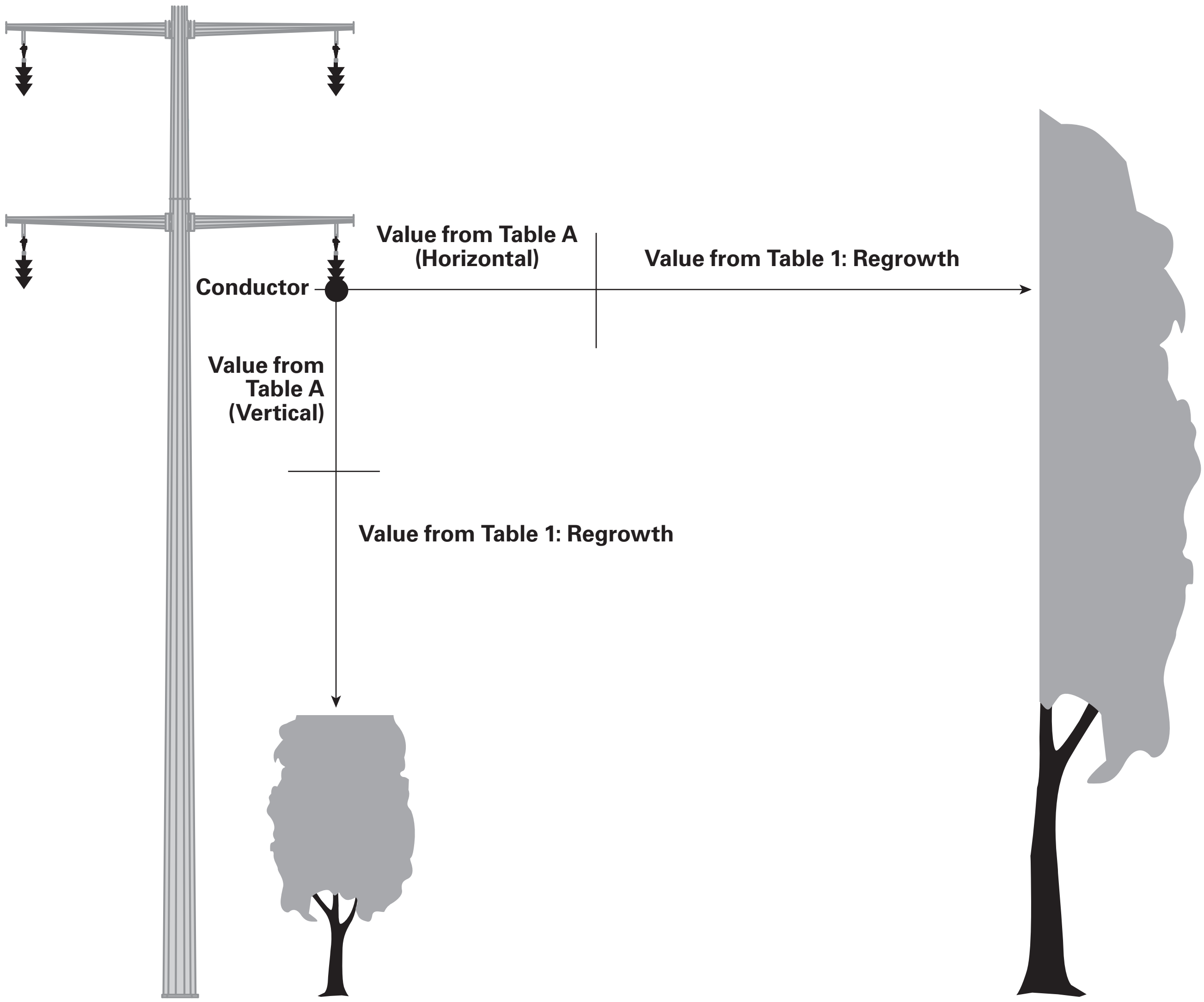
4.2.6 Clearance At Time of Routine Maintenance

The clearance obtained at time of initial clearing and maintenance shall be based on the "Maintained Clearances for Trees" (Table A) and the "Anticipated Tree Re-Growth" (Tables 1).

The following calculations must be performed to determine clearances necessary at time of maintenance:

Horizontal & Vertical Clearance at time of pruning = (Value from Table A) + (Value from Table 1)

Illustration of Horizontal and Vertical Clearance Obtained at Time of Maintenance



4.3 TRANSMISSION LINES THAT FALL WITHIN THE AMBIT OF FAC-003

Priority 1 (P1) clearance distances and the corresponding imminent threat process have been established to best ensure compliance with Requirement 4 (R4):

Voltage	Priority 1 Clearance
<200 kV*	≤5 feet
230 kV	≤10 feet
345 kV	≤15 feet
500 kV	≤20 feet

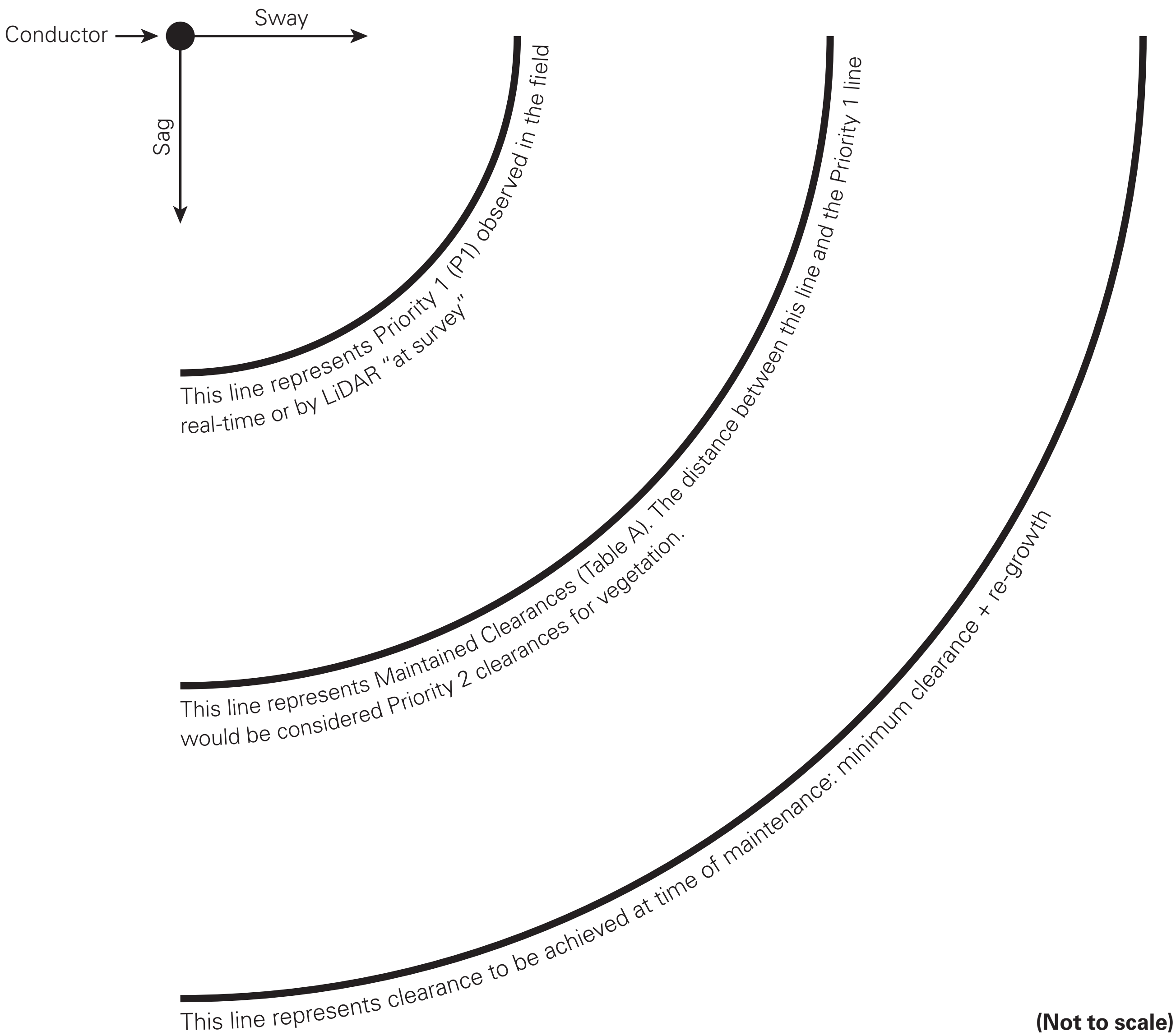
If, at any time, vegetation is observed closer than these priority clearances, the appropriate Company Vegetation Management representative shall be notified immediately.

*Only subject to FAC-003 if specifically designated in those requirements.

Priority 2 (P2) are clearances greater than Priority 1, but less than those outlined in Tables A .

4.3.1 Interrelationship of Transmission VM Clearances Defense-in-Depth

The Company has provided this visual interpretation as a guide to assist with understanding the interrelationship between multiple clearance definitions. If you are ever unclear, please contact the appropriate Company Vegetation Management representative.



4.3.2 LiDAR-Modeled Clearance

Where LiDAR analysis has been performed for routine maintenance purposes and conductor location modeled to maximum sag and sway, the Maintained Clearances for Trees (Table A) are replaced with the Priority 1 (P1) clearance distances to generate the vegetation condition polygons on the maps developed for routine maintenance purposes. The expected re-growth of vegetation for the applicable cycle must be added to the Priority 1 Clearance threshold to determine the minimum amount of clearance that needs to be achieved at the time of vegetation management work. Workers may also need to factor in vegetation growth which has occurred since the date of LiDAR acquisition.

4.4 TYPES OF TRANSMISSION PROJECTS

4.4.1 Routine Maintenance / Scheduled Work

Routine Maintenance is proactive scheduled work performed on a maintenance area basis.

- Contractors are expected to determine the most cost-effective method of safely completing all work performed.
- The surface of the right of way above underground transmission facilities should also be kept free of incompatible vegetation for optimum operation, public safety and facility access considerations for the width of maintained ROW.
- Before entering any easement tract or private property for the purpose of right of way clearing, as a courtesy, an effort shall be made to contact the property owner.
- If contact is successful, the property owner shall be informed of the work to be done. Be aware that a landowner's easement may contain specific language pertaining to vegetation issues.
- If the contractor is unable to contact/locate the owner of any property where work is required, report the situation to a Company Vegetation Management representative.
- If it is necessary to enter the property owner's land to gain access to the right of way, an agreement should be reached on the best route. If an agreement cannot be reached or in the case of an absentee owner, the contractor shall notify their Company Vegetation Management representative.
- The Company may have access route agreements in place on private property parcels and public land. Do not block any access routes with any wood debris. Should additional access routes be needed, or if questions exist, consult with your Vegetation Management representative.
- If any damage to property or crops results, the contractor is responsible for the related claims unless other provisions are made with the Company.
- If a property owner submits a claim, the contractor should contact the owner immediately.

The contractor should obtain a signed, written acknowledgement for any removal or herbicide work done beyond the bounds of the Company's easement or right of way.

4.4.2 Mid-Cycle / Supplemental Inspection

Inspections that may be scheduled on selected maintenance areas for the purpose of identifying and mitigating as needed, vegetation conditions which in the judgement of the inspector, should be addressed prior to the next routine maintenance work. Projects will be assigned by the appropriate Company Vegetation Management representative.

4.4.3 Make Ready Clearance Requests

Only qualified line-clearance contractors, as defined by federal, state or local regulations or laws, can work on trees that have grown closer to power lines than certain distances as outlined in the applicable laws/regulations. Therefore, when requested, the Company (through its contractors) will provide preliminary clearance to help reduce the potential for electrical contact by third-party non-qualified workers. Requests for these clearances are known as "make ready" requests.

It is important that contractor personnel respond to these requests in a prompt and timely manner and in accordance with any laws and regulations. Contractor personnel must also determine the most cost-effective course of action to provide adequate clearance. Examples include:

- Prune the portion of the tree back an adequate distance
- Drop the tree on the ground

As of the publication date, the Company does not currently charge a fee for the pruning or dropping of trees related to make ready requests, but it is important that the contractor clearly communicate to the requesting party that all debris will be left on site and the Company will not dispose of the same.

4.4.4 Internal Reliability Related Requests

It is important that contractors respond to these requests in a prompt and timely manner and in accordance with any instructions provided with the request and in accordance with any laws and regulations. In many cases we expect contractors to make a judgment call as to the required scope of work. Contractors need to consider all factors including the likelihood of vegetation to cause an outage in its current condition, risk to public safety and when the maintenance area map/corridor is due for routine maintenance when making this decision.

4.4.5 Construction / Cross Charge

These requests pertain to the installation of, refurbishment, or work on facilities that are jointly owned. In many cases contractor personnel will be asked to identify the required scope of work and to provide information that will be used to estimate the associated costs. It is important that contractor personnel respond to these requests in a prompt and timely manner and in accordance with any instructions provided with the request and in accordance with any laws and regulations.

4.4.6 Emergency / Storm Response

Contractor personnel are required to respond to storm situations in accordance with the regional storm response process. Only work necessary for the restoration of power will be performed. A reasonable attempt should be made to notify customers. No debris disposal will be attempted for any work performed.

4.4.7 Wildfire Risk Mitigation Programs

Programs may exist in some Company regions specific to lessening risk of wildfire ignition or consequence such as hazard tree mitigation programs, pole clearing, ROW Conversion, and approach to routine maintenance projects. Consult with your Vegetation Management representative for specific instructions.

Contractors shall at all times be aware of fire conditions and restrictions within the area(s) they operate. Contractors shall follow all required regulatory entity restrictions and control requirements. Compliance includes but is not limited to maintaining all necessary firefighting tools and equipment, all necessary fire and suppression training, required reporting, and stop work moratoriums should the governing body or the Company determine unsafe working conditions exist.

SECTION 5: OVERHEAD SAFETY INSPECTION PROGRAM

5.1 DESCRIPTION

Contractors shall perform overhead safety inspections as part of their routine vegetation management operations which includes inspection of the following, regardless of the presence of vegetation:

- Distribution primary conductor
- Distribution secondary and service conductors on the job site
- Transmission facilities
- Other facilities

Contractors are to identify obvious safety hazards on the Company's distribution and transmission overhead facilities that could pose a threat to the general public as well as our employees and contracted workers. Hazards that present an imminent threat to personal or public safety must be resolved immediately; in an emergency, call local Dispatch or Area Control. Depending upon the urgency of the situation, it may be necessary for the inspector to stay on site until a utility representative arrives at the scene.

When a hazard is identified, follow the Overhead Safety Inspection Process.

5.2 SAMPLE LIST OF HAZARDS

The following is a sample list of safety hazards that contractors should be able to recognize. Please note that all situations cannot be listed and good judgment must be used when inspecting.

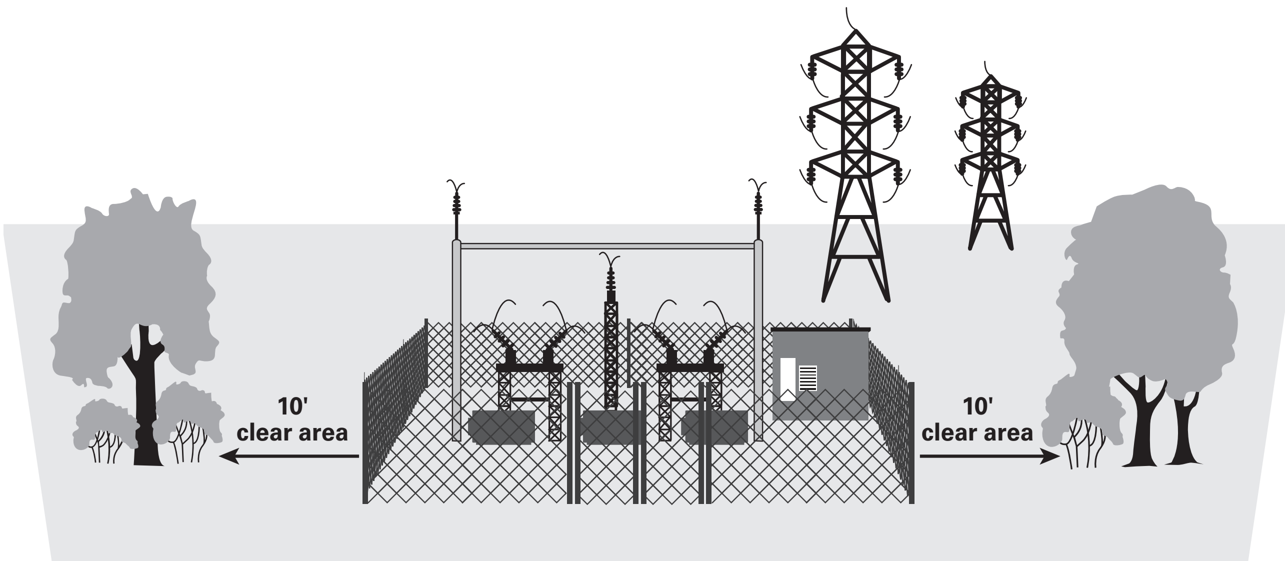
- Cracked or broken cross arms
- Missing cross arm braces
- Guy wires missing or damaged
- Tripping hazards, such as ground wire sticking out from pole
- Oil-filled equipment leaks
- Equipment ready to fall down
- Transmission right of way encroachment
- Clearances of conductors – from buildings, tree houses, ladders, transmission, etc.
- Leaning pole, tower or footing
- Rotted or eroding pole, tower or footing
- Bird nest on a structure
- Significant woodpecker damage to a pole or tower
- Wires down or broken
- Severely frayed conductor or neutral / static wires
- Wires off insulator or pin
- Ground clearances
- Damage to insulator
- Damage to pole top pin
- Damage to pole steps
- Accessible objects hanging from lines
- Meter housing loose from structure
- Mast or riser pulling from housing
- Wires exposed
- Doors to underground equipment and vaults unlocked or open

SECTION 6:
ELECTRIC SUBSTATION, NATURAL GAS, AND OTHER FACILITY WORK

6.1 GENERAL DESCRIPTION

The Company's Vegetation Management group is also responsible for maintaining vegetation at electric substations and at selected gas facilities. In some areas, the Company's Vegetation Management group is also responsible to provide vegetation control services at various assigned generating stations (also known as "power plants"), offices and service centers, telecommunication sites, and other corporate-owned property.

Facilities located on federal lands and some private properties require special notification and treatment types. Contractors are required to contact the appropriate Company Vegetation Management representative.



6.2 SUBSTATION FENCE CLEARANCE

Trees and shrubs growing too close (10 feet or less) to perimeter fences can allow animal access, which can lead to substation transformer outages affecting large numbers of customers. Vegetation can conceal unauthorized human access which creates safety and security concerns and problems with theft.

At the time of distribution and transmission maintenance area work, the contractor shall inspect the perimeter of the substation fence where the circuit originates and clear vegetation which is closer than 10 feet from the fence.

If any newly planted vegetation is identified, or vegetation which appears to be part of a landscape plan, the contractor should consult with the appropriate Company Vegetation Management representative prior to removal.

6.3 SUBSTATION SECURITY AND ACCESS

Any contractor personnel entering substation equipment yards must be qualified employees (OSHA 1910.269) and must have completed Company-sponsored substation hazard awareness training. When instructed to do so, the contractor shall notify dispatch/area control prior to entering any substation and when leaving the substation. Contractors shall close the gate upon entering a substation and lock it upon exiting. Substation gates are to remain secured at all times in accordance with the Company's Substation Access Program. Parking in substations is not allowed unless pre-approved by the appropriate Company Vegetation Management representative.

Contractors need to be aware that there are special conditions that may apply to each region.

SECTION 7:
MISCELLANEOUS VEGETATION MANAGEMENT

7.1 ACTIVITY REPORTING

The Company will provide contractors with a method for reporting their crew activity. Contractors shall record their time and activity, according to each type of activity performed.

7.2 AVIAN PROTECTION

The Company's long-term Avian Protection Plan details the company's efforts to protect facilities and to reduce risks to birds from interactions with company facilities. This plan is part of an agreement outlined in a Memorandum of Understanding with the U.S. Fish and Wildlife Service. The following items in the Avian Protection Plan relate to tree maintenance activity:

- An inactive bird nest is defined as not having eggs or young. If birds are building a nest that does not have eggs or young, it is also inactive.
- If vegetation management crews encounter an inactive nest in a part of the tree which requires pruning, they can remove the nest. There are only two exceptions:
  - Eagle Nest: An inactive eagle nest CANNOT be removed. Before beginning work in proximity to an eagle nest, contact the appropriate Company Vegetation Management representative.
  - Osprey Nest: A Company Vegetation Management representative must be contacted prior to the removal of an osprey nest.
- If vegetation management crews encounter an active nest (eggs or young present), in part of a tree requiring work, the nest cannot be removed until it becomes inactive. The tree may be cleared from the wires, as long as the nest and birds are not disturbed. It is possible that the crew may need to return to complete the tree work once the nest becomes inactive. These situations must be reported to the appropriate Company Vegetation Management representative.
- If vegetation management crews find a dead or injured bird that had come into contact with a line, they must contact their general foreperson. The general foreperson will then contact the assigned Company Vegetation Management representative, who will contact the appropriate Company Avian Protection Specialist.
- Contract general foremen are responsible for keeping the avian protection U.S. Fish & Wildlife Service Special Purpose Permit, on their trucks at all times.

7.3 GLOSSARY FOR TREE WORKERS

Brush – any woody-stemmed plant having <4" diameter at breast height (DBH).

Corridor – see TMA.

Distribution Circuit – is the entire electrical circuit from a substation to a meter including multi-phase and single-phase primary as well as all secondary conductors. At the Company, distribution circuits typically have operating voltages from 4kV to 34.5kV.

Distribution Feeder/Mainline – facilities are multiphase conductors between the substation breaker and the next protective device.

Distribution Tap / Lateral – portion of a distribution voltage circuit that branches off a mainline or feeder. Taps can be single-phase, two-phase, or three-phase.

DMA – a Distribution Maintenance Area is a defined geographical area containing distribution primary and secondary voltages, regardless of the existing electrical circuit configuration.

Hazard Tree – a tree that the Company or its contractor has determined poses an unacceptable risk of failing onto Company facilities.

Hold Site – a temporary suspension of work at a location.

LiDAR (Light Detection And Ranging) – a detection system that works on the principle of radar, but uses light from a laser. For the purposes of utility vegetation management, the laser device is most commonly mounted on the underside of an aerial platform.

Maintenance Area – a defined geographical area for the purpose of vegetation management, regardless of the existing electrical configuration. In most cases, the initial area was defined by the circuit schema that existed when the maintenance area was created and the name was derived from the circuit name. Also referred to as Distribution Maintenance Areas (DMA) and Transmission Maintenance Areas (TMA).

Maintenance Cycle – Each maintenance area has a targeted cycle length for line clearance activity, targeted to repeat after a designated number of years (3, 4, or 5, for example).

Make Ready Clearance Requests – clearance based on non-qualified workers' minimum approach distances to help reduce the potential for electrical contact. Formerly referred to as a Safety Zone clearance.

Primary – distribution voltage facilities (e.g. conductor) generally over 600 volts and up to 34,500 volts (34.5kV).

Secondary – lower voltage conductors, generally less than 600 volts. These include street light wires.

Service – the low-voltage facilities between a customer's house and the pole. Sometimes referred to as the "loop drop."

TMA – a Transmission Maintenance Area is a corridor of maintained right of way usually between two or more substations which may contain multiple transmission lines or portions of transmission lines.

Transmission Circuit – an entire line, including all conductors, as defined by the Company's Transmission Engineering group. At the Company, transmission circuits typically have operating voltages from 34.5kV to 500kV.

Tree – any woody-stemmed plant having ≥4" diameter at breast height (DBH). Count multi-stemmed trees individually if there's any soil between the stems at ground level.

SECTION 8:
CUSTOMER INTERACTIONS & LAND RIGHTS

8.1 GENERAL

Vegetation Management programs impact almost all landowners and customers during the course of maintenance area work, external requests, storm restoration, etc. It is important for all personnel to work towards ensuring a positive customer experience as we interact with landowners. In addition to providing safe, reliable, and cost-efficient energy to our customers, keep in mind some basic guiding principles—we will:

- Listen to our customers
- Be easy to do business with
- Meet our customer commitments
- Set realistic expectations
- Take ownership in finding solutions
- Provide clear, timely and proactive communications
- Ensure public and customer safety

A positive customer experience is dependent upon ownership, cooperation and collaboration.

8.2 NOTIFICATION

Contractors must make reasonable attempts to notify property owners regarding work to be performed. Contractors need to be aware that there are special conditions that may apply to each region.

Distribution: Contractors should obtain written acknowledgement from the landowner for all tree and brush removal, and the application of herbicide.

Transmission: The contractor should obtain a signed, written acknowledgement for any removal or herbicide work done beyond the bounds of the Company's easement or right of way.

8.2.1 Public Utilities Commission (PUC) and Public Service Commission (PSC)

Tariffs and agreements with various state regulatory entities may give utility companies and their contractors the ability to enter private property for maintenance purposes regardless of the existence of an easement or prescriptive rights.

Specific tariffs provisions* include:

COLORADO: Rules and Regulations, General, R86 Access For Company's Employees

MICHIGAN: Rules and Regulations Part 2, Sheet C-2.0, Access To Premises

MINNESOTA: Minnesota Electric Rate Book, Rules and Regulations, Section 1.3, Sheet 6-4, Access To Customer's Premises

NEW MEXICO: New Mexico Rules and Regulations, Original Rule 10, Access To Premises

NORTH DAKOTA: General Rules and Regulations, Section 1.3, Sheet 6-1.1, Access To Customer's Premises

SOUTH DAKOTA: General Rules and Regulations, Section 1.3, Sheet 6-3.1, Access To Customer's Premises

TEXAS: Rules, Regulations, and Conditions of Service, Section V, Rule No. 10, Sheet V-11, Access To Premises

WISCONSIN: Rules and Regulations, Sheet E 90, Schedule Ex-22, Access To Customer's Premises

Copies of tariffs applicable to each state within the Company's service territory can be found in their entirety at xcelenergy.com. If you have any problems with the Company's website, you can also look at the local public utilities commission website or contact the company for a copy of its tariffs.

*Note: the tariff references are as of February 2022.

8.2.2 CUSTOMER / LANDOWNER REFUSALS

If contractor access to company facilities and/or required scope of work is denied by a customer or landowner, notify contractor supervision to attempt a resolution. If the contract supervisor is unable to reach an agreement, notify the appropriate Company Vegetation Management representative. Additionally, any threatening behavior shall be reported to the Company's Enterprise Command Center (ECC).

8.2.3 Land Rights, Rights of Way / Easements / Special Use Permits

Contractors need to be aware that electric transmission, distribution lines and gas may be constructed where legal easements or other land use agreements/rights exist, e.g., a permit, lease or license. Special conditions may apply regarding vegetation management activities pursuant to the terms of these agreements. If questions arise, contact the appropriate Company Vegetation Management representative.

8.2.4 Fee-Owned Rights of Way

The Company's fee-owned rights of way or land is property owned by the Company. The Company may have total control of this property subject to conditions, reservations and encumbrances, license or lease agreements. Adjacent property owner acknowledgement may be required for access. If questions arise, contact the appropriate Company Vegetation Management representative.

8.2.5 Work on Federal Lands

When working on federal lands, contractors shall be aware that the Company owns and operates many electric distribution, electric transmission, and gas facilities situated on federal lands (U.S. Forest Service, Bureau of Land Management, etc.). These facilities are authorized by specific grants or permits from the federal land manager to the Company. In all cases, tree removal on federal lands can only occur after prior permission has been granted by the federal land manager. Therefore, all tree removal on federal lands requires prior consultation with and approval from the appropriate federal land manager. The responsibility for this consultation and approval process rests with the Company, unless otherwise agreed to in writing.

Procedure for vegetation clearance operations on transmission, distribution, gas, and facilities on federal land, after the Company has obtained approval from the appropriate land manager:

- Contractor will meet with designated Company representative before crew start-up at which time specific concerns or requests can be addressed. Any specific requirements or special requests issued by the land manager in which the contractor will be expected to comply will be relayed to the contractor.
- Crew operations on federal lands will strictly adhere to any special requests by the federal agency agreed to by the Company.
- Such special requests can involve, but are not limited to, fire prevention plan procedures and equipment, slash disposal and bucking requirements for merchantable timber, cultural or environment resource training, weekly check in by general foreperson regarding crew location and fire danger level.
- Contractor will obtain any necessary permits for extended overnight stays on federal lands.
- Contractor will obtain approval from the appropriate designated representative before use of ATV or off-road equipment unless specifically authorized. All access to right of way corridor, if not accessible by a designated road or trail, must meet approval of appropriate federal land manager. Should additional access routes be needed, or if questions exist, consult with your Vegetation Management representative.
- Crew operations and access will obey all road closures on federal lands. The opening of closed roads may at times be obtained at the discretion of the appropriate designated representative.
- Crew staging areas and campsites as well as all work areas will be maintained free of litter and in compliance with standards imposed by the federal agency.

It is the contractor's responsibility to ensure that all operations on federal lands are in accordance with conditions set forth within the special use permit, USFS / Company joint operations maintenance agreement, and any other applicable requirements which may apply to vegetation clearance operations.

The use of chemical herbicides and pesticides is also regulated on federal lands. Prior written approval from the federal land manager is required before the application of any herbicide or pesticide. Only those materials registered by the U.S. Environmental Protection Agency for the specific purpose planned will be considered for use on federal lands.

8.3 RESOURCES FOR OUR CUSTOMERS

Useful information for our customers can be found on our website **xcelenergy.com/Trees**. This includes frequently asked questions that customers have about our vegetation management program.

The Company's Plant a Better Future booklet is available on the website, providing customers detailed information regarding potential power line compatible tree planting.

Appendix B - 2024 Remediation Plan for 2023 Top 10% SAIDI & SAIFI

APPENDIX B

2024 Texas Remediation Plan for 2023 Top 10% SAIFI & SAIDI Feeders - Vegetation Related Events Only

Feeder	SAIDI Top 10%	SAIFI Top 10%	# Events	Total CMO	Total SCIs	# SCIs Investigated by Veg Man Dept	# Preventable SCIs Determined by VM Dept	# Non-Preventable SCIs Determined by VM Dept	Vegetation Management Year Last Worked	Vegetation Management Year Scheduled	Remediation Plan?
BUSH5210	X		5	7,829	34	0	0	0	2019	2025	Yes, will inspect main feeder
CNCK1B25	X	X	1	1,507	23	0	0	0	2017	2025	Yes, will inspect main feeder
DENES100	X	X	2	7,513	85	84	0	84	2017	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
ESTA5D20		X	2	3,393	254	107	0	107	2016	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
LAWP1A165	X	X	4	12,743	89	72	72	0	2021	2026	Yes, will inspect main feeder
LAWP1A185	X	X	1	10,764	69	0	0	0	2020	2025	Yes, will inspect main feeder
LAWP1A195	X	X	6	9,998	129	91	91	0	2021	2026	Yes, will inspect main feeder
MCCU5085	X	X	1	5,593	52	52	52	0	2022	2027	Yes, will inspect main feeder
MULWMR140	X	X	3	2,508	47	36	36	0	2016	2025	Yes, will inspect main feeder
PIER5B10	X	X	3	6,702	30	0	0	0	2018	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
PUCW5C35		X	3	3,201	80	0	0	0	2017	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
SGEO2346	X	X	6	4,522	47	0	0	0	2017	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
SHER1452	X		1	198	1	0	0	0	2021	2026	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
SPEA401	X	X	1	1,848	28	0	0	0	2017	2025	Yes, will inspect main feeder
WHDR2C035	X	X	2	16,249	121	112	112	0	2018	2025	Yes, will inspect main feeder
WHIT5265	X	X	1	2,275	6	0	0	0	2020	2025	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.

APPENDIX B

2024 Texas Remediation Plan for 2023 Top 10% SAIFI & SAIDI Feeders - Vegetation Related Events Only

Feeder	SAIDI Top 10%	SAIFI Top 10%	# Events	Total CMO	Total SCIs	# SCIs Investigated by Veg Man Dept	# Preventable SCIs Determined by VM Dept	# Non-Preventable SCIs Determined by VM Dept	Vegetation Management Year Last Worked	Vegetation Management Year Scheduled	Remediation Plan?
WSST2D015	X	X	2	81,830	1,167	1166	0	1166	2018	2025	No,breaker opened in substation because of broken phase while repair cross arm.

Appendix C1 - 2023 Vegetation Annual Filing Feeder SAIDI

Monthly SAIDI by Feeder

Based on 2023 TX QSP Filing Data, Forced Events

Excludes Area Office Storm Days and Substation & Transmission Events. Includes only Vegetation Cause Coded Outages

Includes only feeders that had outages meeting the above criteria in the current reporting year

2023 Top 10 % - 146 Feeders With Vegetation Cause Outages

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
WSST2D015	0.00	69.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.18	70.12
WHIT5265	0.00	0.00	0.00	0.00	0.00	0.00	37.92	0.00	0.00	0.00	0.00	0.00	37.92
WHDR2C035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.63	0.90	0.00	0.00	21.52
CNCK1B25	10.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.25
LAWP1A165	Ret	Ret	0.00	0.00	9.65	0.34	0.00	0.00	0.00	0.00	0.00	0.00	9.98
DENES100	0.00	0.00	0.00	7.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.37
PIER5B10	0.00	0.00	0.00	0.00	2.68	0.00	0.00	2.93	1.72	0.00	0.00	0.00	7.32
LAWP1A185	Ret	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.03	0.00	0.00	7.03
LAWP1A195	Ret	0.00	0.00	0.12	0.00	5.95	0.00	0.00	0.00	0.20	0.00	0.00	6.26
MCCU5085	0.00	0.00	0.00	0.00	0.00	5.21	0.00	0.00	0.00	0.00	0.00	0.00	5.21
SPEA401	0.00	0.00	0.00	5.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.21
BUSH5210	0.00	0.00	0.00	0.56	0.00	3.51	0.00	0.00	0.04	0.04	0.00	0.00	4.14
SGEO2346	0.00	0.00	0.00	0.13	0.00	1.93	0.00	0.00	0.00	2.02	0.00	0.00	4.07
SHER1452	0.00	0.00	0.00	0.00	0.00	0.00	3.80	0.00	0.00	0.00	0.00	0.00	3.80
MULWMR140	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.00	3.29	0.00	0.00	3.77
PARM2475	0.00	3.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.19
LEVCLV190	0.00	1.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.86	0.00	0.09	3.05
BENNS345	0.00	0.48	0.00	0.00	0.00	0.15	0.00	2.10	0.00	0.00	0.00	0.00	2.73
SPEA402	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.72	0.00	0.00	2.72
PLVWP110	0.00	1.85	0.00	0.00	0.16	0.00	0.18	0.00	0.00	0.00	0.00	0.00	2.19
WBOR1A20	0.00	0.00	0.00	0.87	0.00	1.30	0.00	0.00	0.00	0.00	0.00	0.00	2.18
SGEO2338	0.03	0.00	0.00	0.00	0.00	1.26	0.22	0.52	0.00	0.00	0.00	0.04	2.07
LAPL2D65	0.00	0.00	0.00	0.95	0.00	0.00	0.06	0.05	0.23	0.49	0.03	0.03	1.85
ESTA5D20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.83	0.00	0.00	1.83
EPLAA118	0.00	0.03	0.00	0.02	0.00	0.00	1.69	0.00	0.00	0.04	0.00	0.00	1.78
CANW7124	0.00	0.09	0.00	0.00	0.00	1.19	0.39	0.00	0.00	0.06	0.00	0.00	1.73
INDU1416	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.68	0.00	0.00	1.68
SPEA302	0.00	0.00	0.00	0.00	0.00	1.35	0.00	0.00	0.00	0.00	0.30	0.00	1.64
MANH7164	0.00	0.00	0.00	0.00	0.00	0.00	1.54	0.00	0.00	0.00	0.00	0.00	1.54

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
ROXA2076	0.00	0.00	0.00	0.00	0.00	0.00	1.54	0.00	0.00	0.00	0.00	0.00	1.54
SGEO5B40	0.00	0.00	0.00	0.00	0.00	1.53	0.00	0.00	0.00	0.00	0.00	0.00	1.53
ALLRS140	0.00	1.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.52
SGEO2342	0.00	0.00	0.00	0.00	0.00	1.47	0.00	0.00	0.00	0.00	0.00	0.00	1.47
WSST2D025	0.00	0.00	0.00	0.00	0.00	1.46	0.00	0.00	0.00	0.00	0.00	0.00	1.46
PRIN1E15	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00	0.00	0.00	0.00	0.00	1.41
PUCW5C35	0.00	0.14	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.00	0.00	0.97	1.38
BUFF2215	0.00	0.00	0.00	0.00	0.00	0.00	0.83	0.00	0.00	0.53	0.00	0.00	1.37
WRIDP450	0.00	0.00	0.00	0.00	0.00	0.00	1.28	0.00	0.00	0.00	0.00	0.00	1.28
PIER5B05	0.00	0.00	0.07	0.00	0.06	0.08	1.07	0.00	0.00	0.00	0.00	0.00	1.28
LITCLI610	0.00	0.00	0.00	0.00	0.00	1.17	0.00	0.00	0.00	0.00	0.00	0.00	1.17
34ST5B85	0.00	0.00	0.00	0.00	0.23	0.82	0.00	0.00	0.00	0.09	0.00	0.00	1.13
DOSSS495	0.00	0.00	0.79	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.10
HERE2D45	0.00	0.00	0.00	1.07	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	1.10
PIER5B00	0.00	0.00	0.00	0.00	0.00	0.13	0.95	0.00	0.00	0.00	0.00	0.00	1.08
VICK6680	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	0.18	1.01
LYON5C20	0.00	0.00	0.00	0.00	0.00	0.00	0.97	0.00	0.00	0.00	0.00	0.00	0.97
OUTP2A060	0.00	0.00	0.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.93
VANB7046	0.00	0.06	0.00	0.02	0.72	0.00	0.00	0.04	0.06	0.00	0.00	0.00	0.90
PERR1530	0.00	0.00	0.00	0.00	0.00	0.40	0.49	0.00	0.00	0.00	0.00	0.00	0.89
WHIT5270	0.00	0.00	0.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.87
SOEA5C85	0.00	0.00	0.00	0.00	0.00	0.03	0.78	0.00	0.00	0.00	0.00	0.00	0.82
ECHO2A160	Ret	Ret	Ret	Ret	0.00	0.00	0.74	0.00	0.00	0.00	0.05	0.00	0.79
CHAN1675	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00	0.49	0.00	0.00	0.79
HAST7078	0.01	0.00	0.31	0.00	0.05	0.07	0.00	0.12	0.00	0.10	0.00	0.12	0.78
HAST7082	0.00	0.00	0.00	0.62	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.71
CHER5C10	0.00	0.00	0.00	0.00	0.00	0.15	0.55	0.00	0.00	0.00	0.00	0.00	0.70
SLAT6600	0.00	0.00	0.00	0.00	0.00	0.00	0.70	0.00	0.00	0.00	0.00	0.00	0.70
DALH1298	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.53	0.05	0.00	0.00	0.68
SPRD2C80	0.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.65
WHITLV220	0.00	0.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.64
HARTHA120	0.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.61
LYON5C25	0.00	0.10	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00	0.57
INDU1412	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.51	0.00	0.00	0.51
LAPL2D70	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.14	0.00	0.00	0.00	0.50
SPEX1512	0.00	0.00	0.00	0.16	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.50

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
MULVMR155	0.00	0.00	0.00	0.00	0.39	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.47
PLVSP220	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47
PERR1230	0.00	0.00	0.00	0.00	0.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.46
LPSB2580	0.00	0.00	0.00	0.00	0.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	0.45
DEMN2D085	Ret	Ret	Ret	Ret	Ret	0.00	0.00	0.00	0.00	0.44	0.00	0.00	0.44
CANW7128	0.00	0.00	0.00	0.00	0.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.43
LAWP1A190	Ret	0.37	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.43
VANB7198	0.00	0.00	0.00	0.00	0.08	0.17	0.00	0.00	0.00	0.17	0.00	0.00	0.42
PUCW5C30	0.00	0.00	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.41
KISRP965	0.00	0.00	0.00	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.41
OSAG6065	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.27	0.00	0.08	0.00	0.00	0.39
34ST2B45	0.03	0.00	0.00	0.10	0.00	0.19	0.00	0.00	0.03	0.03	0.00	0.00	0.38
ESTA5D15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.00	0.00	0.00	0.00	0.38
PLVEP160	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.37
CANA325	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.36
LITCLI640	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.12	0.00	0.00	0.36
SPEA301	0.00	0.00	0.00	0.00	0.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.36
CANA340	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.35	0.00	0.00	0.00	0.00	0.35
BUSH5205	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.34
WANT3502	0.00	0.21	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.34
CURX3635	0.00	0.00	0.00	0.00	0.20	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.34
SONC5130	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.00	0.00	0.00	0.00	0.34
DIMSDI120	0.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34
HACTHR110	0.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33
VANB7044	0.00	0.25	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.31
MCLE5B105	Ret	Ret	Ret	Ret	Ret	0.00	0.30	0.00	0.00	0.00	0.00	0.00	0.30
LEVELV950	0.00	0.00	0.00	0.00	0.00	0.22	0.08	0.00	0.00	0.00	0.00	0.00	0.30
MULVMR150	0.00	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.30
PLVSP230	0.00	0.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
LITWLI156	0.00	0.00	0.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.29
HAST7074	0.00	0.06	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00	0.00	0.00	0.28
PLAXX310	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.27
SHER1456	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.00	0.27
MURP7535	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.27
HAST7086	0.00	0.00	0.00	0.00	0.00	0.05	0.12	0.00	0.09	0.00	0.00	0.00	0.26
SOEA5C80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.00	0.00	0.00	0.00	0.26

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
ECHO2A170	Ret	Ret	Ret	Ret	Ret	0.00	0.19	0.06	0.00	0.00	0.00	0.00	0.25
LYNN6300	0.16	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25
HOWA2485	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.00	0.00	0.24
MORTM130	0.00	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.24
SLAT6690	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.24
BRIS3434	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.23
HILS2B040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.00	0.00	0.00	0.00	0.23
CANE5185	0.00	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00	0.21
SLATSL140	0.00	0.00	0.00	0.00	0.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.21
ARRO5D85	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.07	0.20
PERR1235	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.20
LAWP1A175	Ret	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.18
SEMX6E00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.17
FRIO2436	0.00	0.00	0.00	0.10	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.15
DALH1246	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.10	0.00	0.14
PLVNP260	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13
MOORM065	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.00	0.13
HIGH5335	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.12
MANH7160	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.12
34ST5B95	0.00	0.00	0.00	0.00	0.05	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.12
CARL6650	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.12
FARM5395	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.11
WHIT5260	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.06	0.00	0.11
HERE2D50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.11
LEVCLV180	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.10
MCCU7002	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.10
MCCU7005	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.10
DOSSS410	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10
CANE5190	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.09
LAWP1A170	Ret	Ret	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.09
WBOR1A10	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
WEAT1350	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.09
DIMEDI150	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
EPLAA110	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08
DENES110	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.08
OUTP2A055	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
LITSLI110	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.07
MOSS6320	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.06
FARM5390	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.06
EPLAA126	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
EPLAA122	0.00	0.00	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05
KITE7106	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.03
DOSS6670	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.03
KISRP960	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
ESTA5D65	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
State of TX	**0.01**	**0.35**	**0.01**	**0.08**	**0.07**	**0.18**	**0.11**	**0.04**	**0.08**	**0.11**	**0.01**	**0.02**	**1.06**

Appendix C2 - 2023 Vegetation Annual Filing Feeder SAIFI

Monthly SAIFI by Feeder

Based on 2023 TX QSP Filing Data, Forced Events

Excludes Area Office Storm Days and Substation & Transmission Events. Includes only Vegetation Cause Coded Outages

Includes only feeders that had outages meeting the above criteria

2023 Top 10 % - 146 Feeders With Vegetation Cause Outages

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
WSST2D015	0.000	0.999	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	1.000
WHDR2C035	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.148	0.012	0.000	0.000	0.160
CNCK1B25	0.156	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.156
ESTA5D20	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.137	0.000	0.000	0.137
WHIT5265	0.000	0.000	0.000	0.000	0.000	0.000	0.100	0.000	0.000	0.000	0.000	0.000	0.100
DENES100	0.000	0.000	0.000	0.083	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.083
LAWP1A195	Ret	0.000	0.000	0.001	0.000	0.080	0.000	0.000	0.000	0.001	0.000	0.000	0.081
SPEA401	0.000	0.000	0.000	0.079	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.079
MULWMR140	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.000	0.065	0.000	0.000	0.071
LAWP1A165	Ret	Ret	0.000	0.000	0.065	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.070
MCCU5085	0.000	0.000	0.000	0.000	0.000	0.048	0.000	0.000	0.000	0.000	0.000	0.000	0.048
LAWP1A185	Ret	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.045	0.000	0.000	0.045
SGEO2346	0.000	0.000	0.000	0.011	0.000	0.017	0.000	0.000	0.000	0.014	0.000	0.000	0.042
PUCW5C35	0.000	0.003	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.028	0.034
PIER5B10	0.000	0.000	0.000	0.000	0.010	0.000	0.000	0.011	0.012	0.000	0.000	0.000	0.033
ALLRS140	0.000	0.029	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.029
LITCLI610	0.000	0.000	0.000	0.000	0.000	0.024	0.000	0.000	0.000	0.000	0.000	0.000	0.024
SPEA402	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.000	0.000	0.023
LAPL2D65	0.000	0.000	0.000	0.009	0.000	0.000	0.001	0.000	0.004	0.007	0.000	0.000	0.021
SONC5130	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.019	0.000	0.000	0.000	0.000	0.019
SHER1452	0.000	0.000	0.000	0.000	0.000	0.000	0.019	0.000	0.000	0.000	0.000	0.000	0.019
PLVWP110	0.000	0.012	0.000	0.000	0.001	0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.019
LYON5C20	0.000	0.000	0.000	0.000	0.000	0.000	0.018	0.000	0.000	0.000	0.000	0.000	0.018
BUSH5210	0.000	0.000	0.000	0.005	0.000	0.012	0.000	0.000	0.001	0.001	0.000	0.000	0.018
CANW7124	0.000	0.000	0.000	0.000	0.000	0.010	0.006	0.000	0.000	0.000	0.000	0.000	0.016
34ST5B85	0.000	0.000	0.000	0.000	0.001	0.014	0.000	0.000	0.000	0.001	0.000	0.000	0.016
INDU1416	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.016	0.000	0.000	0.016
LEVCLV190	0.000	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009	0.000	0.001	0.015

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
HARTHA120	0.000	0.014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.014
PARM2475	0.000	0.014	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.014
WBOR1A20	0.000	0.000	0.000	0.007	0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.000	0.013
ROXA2076	0.000	0.000	0.000	0.000	0.000	0.000	0.013	0.000	0.000	0.000	0.000	0.000	0.013
BUFF2215	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.004	0.000	0.000	0.012
PRIN1E15	0.000	0.000	0.000	0.000	0.000	0.000	0.012	0.000	0.000	0.000	0.000	0.000	0.012
SGEO2338	0.000	0.000	0.000	0.000	0.000	0.004	0.003	0.004	0.000	0.000	0.000	0.000	0.011
WSST2D025	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.000	0.000	0.011
SGEO5B40	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.000	0.000	0.011
SLAT6600	0.000	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.000	0.011
SGEO2342	0.000	0.000	0.000	0.000	0.000	0.011	0.000	0.000	0.000	0.000	0.000	0.000	0.011
BENNS345	0.000	0.003	0.000	0.000	0.000	0.001	0.000	0.006	0.000	0.000	0.000	0.000	0.009
PIER5B05	0.000	0.000	0.001	0.000	0.001	0.001	0.006	0.000	0.000	0.000	0.000	0.000	0.009
HERE2D45	0.000	0.000	0.000	0.008	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.009
DOSSS495	0.000	0.000	0.004	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009
WHIT5270	0.000	0.000	0.000	0.009	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.009
MANH7164	0.000	0.000	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.000	0.000	0.000	0.008
HAST7078	0.000	0.000	0.004	0.000	0.000	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.008
PERR1530	0.000	0.000	0.000	0.000	0.000	0.002	0.006	0.000	0.000	0.000	0.000	0.000	0.008
PUCW5C30	0.000	0.000	0.000	0.000	0.000	0.008	0.000	0.000	0.000	0.000	0.000	0.000	0.008
ECHO2A160	Ret	Ret	Ret	Ret	0.000	0.000	0.007	0.000	0.000	0.000	0.000	0.000	0.008
LAPL2D70	0.000	0.000	0.000	0.006	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.008
LYON5C25	0.000	0.001	0.000	0.000	0.000	0.000	0.007	0.000	0.000	0.000	0.000	0.000	0.008
VICK6680	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.001	0.007
HAST7082	0.000	0.000	0.000	0.006	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.007
SPEA302	0.000	0.000	0.000	0.000	0.000	0.005	0.000	0.000	0.000	0.000	0.002	0.000	0.007
CHER5C10	0.000	0.000	0.000	0.000	0.000	0.001	0.006	0.000	0.000	0.000	0.000	0.000	0.007
SOEA5C85	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.007
EPLAA118	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.007
CANW7128	0.000	0.000	0.000	0.000	0.000	0.007	0.000	0.000	0.000	0.000	0.000	0.000	0.007
DEMN2D085	Ret	Ret	Ret	Ret	Ret	0.000	0.000	0.000	0.000	0.007	0.000	0.000	0.007
PIER5B00	0.000	0.000	0.000	0.000	0.000	0.001	0.005	0.000	0.000	0.000	0.000	0.000	0.006
VANB7046	0.000	0.001	0.000	0.000	0.004	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.006
OUTP2A060	0.000	0.000	0.006	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006
INDU1412	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.006	0.000	0.000	0.006

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
HILS2B040	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.005	0.000	0.000	0.000	0.000	0.005
WRIDP450	0.000	0.000	0.000	0.000	0.000	0.000	0.005	0.000	0.000	0.000	0.000	0.000	0.005
WEAT1350	0.000	0.000	0.000	0.000	0.000	0.005	0.000	0.000	0.000	0.000	0.000	0.000	0.005
LITCLI640	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.002	0.000	0.000	0.005
HOWA2485	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.004	0.000	0.000	0.000	0.000	0.004
SPRD2C80	0.000	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.004
LITWLI156	0.000	0.000	0.000	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.004
CURX3635	0.000	0.000	0.000	0.000	0.002	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.004
CHAN1675	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.004
WHITLV220	0.000	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.004
DALH1298	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.004
PERR1230	0.000	0.000	0.000	0.000	0.000	0.004	0.000	0.000	0.000	0.000	0.000	0.000	0.004
34ST2B45	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.003
MULVMR155	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.003
LAWP1A190	Ret	0.003	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.003
WANT3502	0.000	0.002	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.003
PLVEP160	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003
SPEX1512	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.003
PLAXX310	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.003
DOSSS410	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003
DIMSDI120	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003
SOEA5C80	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.003
LPSB2580	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.003
HAST7086	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.001	0.000	0.000	0.000	0.003
ESTA5D15	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.003
PLVNP260	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003
CANA325	0.000	0.000	0.000	0.000	0.000	0.003	0.000	0.000	0.000	0.000	0.000	0.000	0.003
MURP7535	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.003	0.003
VANB7198	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.000	0.000	0.001	0.000	0.000	0.003
VANB7044	0.000	0.002	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.002
LYNN6300	0.001	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
MORTM130	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.002
SLAT6690	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.002
PLVSP230	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
CANA340	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.002

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
SPEA301	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.002
BRIS3434	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.002
MULVMR150	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.002
BUSH5205	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.002
HAST7074	0.000	0.001	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.002
MCLE5B105	Ret	Ret	Ret	Ret	Ret	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.002
SLATSL140	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.002
SHER1456	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.002
LAWP1A175	Ret	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.002
OSAG6065	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.001	0.000	0.000	0.002
MANH7160	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.002
KITE7106	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.002
HACTHR110	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
DALH1246	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.001	0.000	0.002
EPLAA126	0.000	0.000	0.000	0.000	0.002	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.002
PLVSP220	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
CANE5185	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.001
KISRP965	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.001
LEVELV950	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.001
ECHO2A170	Ret	Ret	Ret	Ret	Ret	0.000	0.001	0.001	0.000	0.000	0.000	0.000	0.001
HERE2D50	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001
ARRO5D85	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
34ST5B95	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
FRIO2436	0.000	0.000	0.000	0.001	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.001
DIMEDI150	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
WHIT5260	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.001
DENES110	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
FARM5395	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001
EPLAA110	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
SEMX6E00	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.001
CARL6650	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.001
MOORM065	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.001
LAWP1A170	Ret	Ret	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.001
HIGH5335	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.001
CANE5190	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.001
LEVCLV180	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001

Feeder	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YearEnd
WBOR1A10	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
MCCU7002	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
MOSS6320	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.001
KISRP960	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
MCCU7005	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
OUTP2A055	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001
LITSLI110	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.001
PERR1235	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
FARM5390	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.001
EPLAA122	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DOSS6670	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ESTA5D65	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
State of TX	**0.000**	**0.005**	**0.000**	**0.001**	**0.000**	**0.001**	**0.001**	**0.000**	**0.001**	**0.002**	**0.000**	**0.000**	**0.012**

Appendix D - 2023 Remediation Plan for 2022 Top 10% SAIDI & SAIFI

APPENDIX B

2023 Texas Remediation Plan for 2022 Top 10% SAIFI & SAIDI Feeders - Vegetation Related Events Only

Feeder	SAIDI Top 10%	SAIFI Top 10%	# Events	Total CMO	Total SCIs	# SCIs Investigated by Veg Man Dept	# Preventable SCIs Determined by VM Dept	# Non-Preventable SCIs Determined by VM Dept	Vegetation Management Year Last Worked	Vegetation Management Year Scheduled	Remediation Plan?
BENNS345	X	X	2	12,480	60	60	60	0	2017	2023	Yes,scheduled to be worked this year.
CANA325	X		1	1,400	8	0	0	0	2020	2023	Yes,scheduled to be worked this year.
CANA335		X	1	1,050	10	0	0	0	2020	2023	Yes,scheduled to be worked this year.
CANW7128	X	X	2	15,961	66	65	0	0	2016	2023	Yes,scheduled to be worked this year.
DALH114	X	X	4	30,104	80	0	0	0	2021	2026	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
DALH1664		X	1	318	3	0	0	0	2021	2026	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
EPLAA126		X	2	1,113	21	0	0	0	2017	2023	Yes,scheduled to be worked this year.
FARWFA610	X	X	2	1,512	12	0	0	0	2017	2024	Yes, will inspect main feeder
HOWA2485	X	X	2	4,772	42	42	0	0	2022	2027	No,Maintenance of this circuits was completed last year.
KITE7106	X	X	4	3,515	61	32	32	0	2022	2027	No,Maintenance of this circuits was completed last year.
LPSB1E40	X	X	2	3,791	17	0	0	0	2022	2027	No,Maintenance of this circuits was completed last year.
MOSS6540	X	X	2	2,816	22	0	0	0	2017	2024	Yes, will inspect main feeder
PERR1230	X		2	3,045	19	0	0	0	2018	2024	Yes, will inspect main feeder
RIVER100	X	X	2	4,792	22	0	0	0	2020	2025	Yes, will inspect main feeder
VANB7048	X	X	4	1,547	19	0	0	0	2021	2026	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.
WSST2D020	X		5	8,865	26	0	0	0	2021	2026	No,outage events were secondary voltages.Only primary outages events (<240V) will be work.

Decision No. R21-0109

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20A-0300E

IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR APPROVAL OF WILDFIRE MITIGATION PLAN AND WILDFIRE PROTECTION RIDER.

**RECOMMENDED DECISION OF
ADMINISTRATIVE LAW JUDGE
ROBERT I. GARVEY
GRANTING APPLICATION
AND DENYING RIDER**

Mailed Date: February 26, 2021

TABLE OF CONTENTS

I. STATEMENT

1. On July 17, 2020, Public Service Company of Colorado (Public Service or the Company) filed with the Colorado Public Utilities Commission (Commission), a Verified Application (Application) for approval of its proposed Wildfire Mitigation Plan (WMP) and Wildfire Protection Rider (WPR).

2. In the Application, Public Service requests that the Commission: (1) approve the proposed WMP provided in Attachment SLJ-1 to the Application as reasonable and in the public interest; (2) authorize Public Service to implement its proposed WPR consistent with the terms and conditions reflected in the illustrative WPR tariff (Attachment BAT-2); (3) approve the Company's revenue requirement calculation as reflected in Attachment APF-1 (which will be used for the first annual WPR true-up adjustment), and approve the calculated 2021 WPR revenue requirement of $17,185,038 (contained in Attachment APF-1); (4) authorize the Company to file a compliance advice letter within 20 days of the effective date of a final order in this proceeding, but on not less than 15 days' notice, with WPR tariff sheets reflecting all terms and conditions that are approved as a result of this proceeding; and (5) authorize Public Service to defer the expenses incurred in connection with this proceeding

into a regulatory asset without interest until they are included as expenses in its next Phase I electric rate case.[1]

3. During the Commission's weekly meeting held on August 26, 2020, the Application was deemed complete for purposes of § 40-6-109.5, C.R.S. (2019), and was referred to an Administrative Law Judge (ALJ) for disposition.

4. On July 30, 2020, the Colorado Office of Consumer Counsel (OCC) filed a Notice of Intervention of Right, Request for Hearing, and Entry of Appearance (OCC's Intervention). The OCC's Intervention is of right and identified twelve issues it may address regarding the Application.[2]

5. On August 24, 2020, Trial Staff of the Colorado Public Utilities Commission (Staff) filed a Notice of Intervention as of Right by Staff, Entry of Appearance, Notice Pursuant to Rule 1007(a) and Rule 1401, and Request for Hearing (Staff's Intervention). Staff's Intervention is of right and identified four specific issues it will raise and address in this proceeding.[3]

6. On August 14, 2020, Colorado Energy Consumers (CEC) filed a Motion to Permissively Intervene and Request for Hearing, pursuant to Rule 1401(c) of the Commission's Rules of Practice and Procedure, 4 *Code of Colorado Regulations* (CCR) 723-1. On August 17, 2020, CEC filed an Amended Motion to Permissively Intervene and Request for Hearing (collectively, CEC's Motion to Intervene) to add the conferral report required by Rule 1400(a) of the Rules of Practice and Procedure, 4 CCR 723-1.

[1] Application, pp. 1-2.
[2] OCC's Intervention, pp. 2-3.
[3] Staff's Intervention, pp. 1-2.

7. On September 15, 2020, by Decision No. R20-0663-I, CEC's Motion to Intervene was granted, and a prehearing conference was scheduled for September 29, 2020.

8. On September 24, 2020, Public Service filed its Unopposed Motion to Approve Procedural Schedule, Vacate Prehearing Conference And Request Waiver of Response Time.

9. On October 2, 2020, by Decision No. R20-0705-I, the prehearing conference was vacated, and a procedural schedule was adopted.

10. On January 7, 2021, Staff, the OCC and CEC (collectively, the Intervenors) filed their Joint Motion to Modify Procedural Schedule for Leave to File Additional Testimony (Joint Motion).

11. On January 11, 2021, the Intervenors filed their Unopposed Joint Motion to Modify Procedural Schedule for Leave to File Additional Testimony (Unopposed Joint Motion)

12. On January 14, 2021, the above-captioned proceeding was called via video conferencing at 9:00 a.m.[4] At the start of the hearing, the Joint Motion was denied, and the Unopposed Joint Motion was granted.

13. Hearing Exhibits 100-111, 113-19, 300, 500-514 were admitted by stipulation of the parties. Hearing Exhibits 112, 130, 305, 310, 314, 320-322, 324-327, 400-40 were admitted during the hearing. Administrative notice was taken of paragraph 68 of Decision No. C21-0017 in Proceeding No. 20A-0204E.

14. Public Service offered the testimony of Ms. Brooke Trammel, Ms. Sandra Johnson, Mr. Steven Rohling, and Mr. Randy Lyle. Staff offered the testimony of Mr. Gene

[4] The hearing was held via video conferencing due to the Covid-19 pandemic.

Camp, and the OCC offered the testimony of Dr. Scott England. At the conclusion of the evidence, the record was closed. The matter was then taken under advisement.

15. Pursuant to § 40-6-109, C.R.S., the ALJ now transmits to the Commission the record of the hearing and a written recommended decision in this proceeding.

II. FINDINGS OF FACT

16. The Partial Wildfire Mitigation Settlement Agreement (Wildfire Mitigation Settlement) in the Company's 2019 Electric Rate Case specified that if Public Service did not file a Phase I rate case on or before August 1, 2020, the Company would file a separate application to present its comprehensive WMP on or before that date.[5]

17. Areas where forests meet the edges of urban areas, referred to as the wildland urban interface, face an increased threat from wildfires due to increased human interaction, activities that could result in the ignition of a fire, and the presence of substantial surface fuel.[6]

18. The WMP at issue encompasses the Company's completed activities in 2019 and 2020, along with the activities planned through 2025.[7]

19. The primary actions contained in the Company's WMP include:

a) Accelerated and enhanced equipment and vegetation inspections and replacements, system protection and wind strength modeling programs, and asset data gathering;

b) System protection enhancements;

c) Expanded and incremental vegetation management;

d) Repair and replacement activities of equipment identified through inspections, system protection, and wind modeling programs;

e) Metrics, tracking, and reporting;

[5] Hearing Exhibit 101, p. 17:11-14.

[6] Hearing Exhibit 101, p. 14:6-10.

[7] Hearing Exhibit 101, p. 32:13-14.

f) Community and stakeholder outreach; and

g) Ongoing assessment of other activities for future consideration.

III. ISSUES

20. Should Public Service's WMP be approved?

21. Should Public Service's proposed WPR be implemented?

IV. APPLICABLE LAW

22. As the proponent of a Commission order, Public Service has the burden of persuasion in this proceeding pursuant to Rule 1500, 4 CCR 723-1, of the Commission's Rules of Practice and Procedure.

23. The evidence must be "substantial evidence," which is defined by the Colorado Supreme Court as: "such relevant evidence as a reasonable [person's] mind might accept as adequate to support a conclusion ... it must be enough to justify, if the trial were to a jury, a refusal to direct a verdict when the conclusion sought to be drawn from it is one of fact for the jury." *City of Boulder v. Colorado Public Utilities Commission*, 996 P.2d 1270, 1278 (Colo. 2000) (quoting *CF&I Steel, L.P. v. Public Utilities Commission*, 949 P.2d 577, 585 (Colo. 1997)). The preponderance standard requires the finder of fact to determine whether the existence of a contested fact is more probable than its non-existence. *Swain v. Colorado Department of Revenue*, 717 P.2d 507 (Colo. App. 1985). A party has met this burden of proof when the evidence, on the whole and however slightly, tips in favor of that party.

24. The Commission has an independent duty to determine matters that are within the public interest. *See Caldwell v. Public Utilities Commission*, 692 P.2d 1085, 1089 (Colo. 1984).

V. ARGUMENTS OF THE PARTIES

A. Public Service

1. Wildfire Mitigation Plan

25. Public Service points out that the Intervenors support the WMP and agree that it is reasonable and appropriate to provide safe, proper, adequate, and sufficient service to customers.[8]

26. In addition, Public Service states that no party contests the reasonableness of the WMP budget, Wildfire Risk Model, or the reasonableness of the Wildfire Risk Zone.[9]

27. Public Service urges the Commission to approve the WMP and find that it is reasonable and in the public interest, and to authorize the Company to recover eligible wildfire transmission costs through the Transmission Cost Adjustment (TCA).

2. Wildfire Protection Rider

28. Public Service argues the scope of work, timeline, and costs associated with the WMP are not in the ordinary course of busines. These projects are either new or accelerated from the routine operation.[10] Because these activities are not in the ordinary course of business, the WPR is necessary.

29. Public Service states that the WPR would have multiple guardrails to protect ratepayers and points out that Staff acknowledged that it is likely all capital investments would be granted in its next electric rate case.

[8] Public Service's Statement of Position, p. 8 (citing the Intervenor's Stipulation at p. 2).
[9] *Id.* at pp. 9-12.
[10] Public Service's Statement of Position, p. 13.

30. In addition, the WPR would include a true-up provision to ensure the Company does not recover costs that it did not incur in any given year, and that there is no over- or under-recovery of costs incurred under the WMP.

31. Finally, Public Service argues that the WPR will streamline the issues presented for review in an electric rate case and smooth out bill impacts rather than resulting in a relatively larger one-time bill increase for the WMP-associated costs after a rate case.

32. In the alternative, given the current economic crisis due to the worldwide pandemic, Public Service provides a deferred accounting proposal.

33. Public Service's deferred accounting proposal calls for the following:

a) Authorize the deferral of costs for a duration aligned with the timeline of the WMP, with the opportunity to review costs as part of a Phase I rate case filed during the five-year term;

b) Establish two deferred accounting mechanisms: one to defer monthly depreciation expense and interest associated with the full level of distribution capital placed into service through December 31, 2025, and the second to defer incremental distribution operations and maintenance O&M for calendar years 2021-2025; and

c) Authorize accrual of interest on the deferred account related to distribution capital at the Company's after-tax WACC (with no return on the deferred account related to distribution O&M).

34. Public Service argues that the Intervenors' deferred accounting proposal is unreasonable because it would apply to less than five percent of the total uncontested capital additions in the WMP.

35. Public Service believes that operations and maintenance costs (O&M) should not be excluded from the authorized deferral and points out that O&M has been included in previous riders. In addition, concerns about double recovery and the ability to track and audit have been addressed by the Company.

36. Finally, Public Service urges the Commission to authorize a return on the deferred account equal to the Company's after-tax weighted average cost of capital (WACC), which would be consistent with the rate of return authorized in its 2019 Phase one Electric Rate Case.

B. Intervenors

37. The Intervenors filed a Joint Stipulation (Stipulation) concerning the issues in this proceeding. Their arguments will be considered as one.

1. Wildfire Mitigation Plan

38. The Intervenors each agree that the WMP should be adopted in its entirety.

39. The Intervenors agree that the planned activities are reasonable and appropriate to provide safe proper, adequate and sufficient service to customers pursuant to § 40-4- 101(1), C.R.S.

2. Wildfire Protection Rider

40. All Intervenors oppose the WPR. The Intervenors argue that the WPR would be an extraordinary cost recovery that is not warranted in the instant case.

41. The Intervenors argue that the Company has stated with or without the approval of the WPR, the WMP will be undertaken and the speed with which it is implemented will not be affected. Thus, the need for this extraordinary recovery has not been shown by the Company.

42. In addition, no other public utility in the West has sought to recover the costs of a wildfire mitigation plan through a rider.[11]

43. The Intervenors recognize the need to implement the WMP but believe these actions are in the ordinary course of business. In recognizing the public need for the WMP, the

[11] CEC's Statement of Position, p. 9.

Intervenors propose the following deferred accounting treatment as contained in the Stipulation filed the week of the evidentiary hearing:

> [The Intervenors] recommend that Public Service be allowed to book into a deferred account only the monthly depreciation expenses related to the following capital investments placed in service (moved into rate base) for two (2) years for the calendar years 2021 and 2022:
>
> (1) Distribution and Pole Repair or Replacements, Overhead Rebuilds, or Repair or Replace Components identified by infrared inspection that are located within the Wildfire Risk Zones designated as "Highest" or "High Risk" demarcated with a (5) and (4) ranking in the Company's direct testimony and exhibits and
>
> (2) all other distribution capital investments proposed with exception of the ADMS Enhanced Circuit Breaker Functionality program. The annual amount of capital expenses for which depreciation can be deferred is limited to no more than 100 percent of the Company's proposed spending for each specific WMP measure completed in each of the calendar years 2021 and 2022 for these "Highest" and "High Risk" projects.[12]

44. The Intervenors also request that Public Service be required to include in its TCA filings, identification of wildfire capital for which TCA recovery is being sought, and detail the amounts expended for each of the five (5) wildfire risk zones.

45. The Intervenors also request the establishment of Wildfire Mitigation Key Performance Indicators to be filed in this proceeding on or before April 1, 2022, for the calendar year 2021, and on or before April 1, 2023, for the calendar year 2022.

VI. DISCUSSION

A. Wildfire Mitigation Plan

46. The experience of numerous wildfires over the past few years, and the last year in particular, show the ever-present need to be prepared for wildfires in the State of Colorado. Working to avoid these disasters is a vital service the Commission can provide to the citizens of

[12] Stipulation, p. 3 (footnotes omitted).

Colorado. The State, and this Commission in particular, should not engage in or encourage a policy of waiting until a utility-caused wildfire before taking preventive measures.

47. An active program by a public utility to curb wildfires and hopefully lessen the severity of wildfires has a benefit to the utility but also to all residents of the State of Colorado. Public Service should be commended for addressing this potential risk.

48. The experience of the nation in the past few years concerning wildfires and other natural disasters has shown the importance and necessity of preventative measures.

49. There is no question the WMP at issue in the instant case is in the public interest and should and will be approved.

B. Wildfire Protection Rider

50. The central question in this proceeding concerns recovery for these necessary measures. The Company favors a rider that will be added to the bills of ratepayers and followed by a true-up provision.

51. The Intervenors object to the WPR with the primary focus being that this work is in the ordinary course of business and should not receive extraordinary treatment.

52. If approved, the WPR would create a new line item charge for all ratepayers of Public Service. Presently, while this proceeding is at issue, there is a global pandemic which has been on-going for more than one year. This pandemic has caused financial hardship for much of this state and much of the country.

53. Under these circumstances, it is difficult to approve an additional charge on ratepayers' bills when so many are facing disconnection for failure to pay their utility bill. The economic conditions of the State cannot be ignored and must be taken into account.

54. In addition, although only proposed to be a five-year rider, the undersigned ALJ is concerned that it may extend beyond that period. As the questioning of Mr. Camp indicated, many riders that are approved for a time certain are extended indefinitely.[13]

55. The undersigned ALJ believes that in order to approve a rider and allow for this extraordinary cost recovery, there either needs to be a statutory provision or an emergency situation or near-emergency situation. At all times, the needs and effect on the ratepayers must be balanced with those of the utility.

56. In the instant case, Public Service has indicated that it intends to move forward with the measures in the WMP at the same pace regardless of whether there is an approved rider.[14] Given this admission, there is very little to no benefit to the ratepayers for an immediate bill increase. With the current economic conditions, and muted benefit to ratepayers but clear benefit to the utility, the addition of a rider is not warranted and would not be just or reasonable.

57. Although there is insufficient evidence to allow for the approval of the WPR, there is a need for the Commission to show its support for enactment of the WMP. The WMP is part of the Wildfire Mitigation Settlement in Proceeding No. 19AL-0268E. The Commission has ordered this plan, and although the costs would be recoverable in the Company's next rate case, it is appropriate to provide an incentive for Public Service to implement this plan as quickly as possible.

[13] Hearing Transcript Vol II, pp. 76-83.

[14] Hearing Transcript Vol. I, p. 176:5-15.

58. Although Public Service indicates the WMP will be timely enacted, the risk of a wildfire and its collateral damage is too great not to provide a financial incentive to ensure these measures are taken in a timely manner.[15]

59. The deferred accounting proposals by Public Service and the Intervenors provide the financial incentive to the utility without an immediate increase to the ratepayers' bills. The deferred accounting strikes a proper balance of an incentive to the Company, but not at the cost of an immediate burden on the ratepayers.

60. During the hearing, Public Service described the Intervenors' deferred accounting proposal in the Stipulation as addressing only a "sliver" of the cost of the WMP.[16]

61. The Intervenors regarded their deferred accounting proposal as "significant movement and compromise."[17]

62. There are points of contention within each of the deferred accounting proposals. Each point of contention will be reviewed to craft a deferred accounting treatment that balances the needs of the utility with those of the ratepayers.

1. Capital Eligibility Threshold

63. Public Service argues that the Stipulation limits eligibility for deferred treatment for the cost of pole replacement to only those poles designated a (4) or (5), which is defined as

[15] The recent winter weather events in the State of Texas show that without proper incentive, there is the risk of the utility failing to enact proper preventative measures which could lead to a disaster. The undersigned ALJ believes that with the proper incentive, the utility should and will work to avoid these risks.

[16] Hearing Transcript Vol I. p. 35:5-11.

[17] Stipulation, p. 2.

being in high risk or highest risk locations, respectively. The Company argues that a pole's designation is determined by its location, rather than the actual condition of the pole. It argues a pole listed as a (2) or (3), in fact, could be in worse condition than a pole listed as a (4) or (5).

64. Public Service points to the admission by Staff witness Camp that poles listed as a (3) could be in worse condition than poles listed as a (4) or (5).[18]

65. Staff in its Statement of Position argues that moderate risk poles (designated as a (1), (2), or (3)) do not represent an exceptional fire risk. In addition, Staff believes that the elimination of these poles will lessen the possibility Public Service will exceed its projected cost estimates.[19]

66. The OCC argues that nothing prevents the Company from recovery of these lesser risk poles in a general rate case.[20]

67. CEC argues that the pole limitation is just and reasonable and consistent with prior limitations on approved deferred accounting. CEC believes that a limitation such as this is necessary to counterbalance single-issue ratemaking mechanisms such as deferred accounting treatment.[21]

68. This limitation on recovery appears to be arbitrary and unnecessary. As pointed out by the Company, it is only the location, not the condition of the pole, that determines whether the pole is designated as high-risk. The condition of a moderate risk pole could be worse than a high-risk pole, yet it would not be subject to deferred accounting treatment. The limitation proposed by the Intervenors shall be rejected.

[18] Hearing Transcript Vol II. pp. 55:23-56:22.
[19] Staff's Statement of Position, pp. 8-9.
[20] OCC's Statement of Position, p. 5.
[21] CEC's Statement of Position, p. 7.

2. O&M Costs

69. Public Service argues that the O&M costs should be included for deferred accounting treatment. The Company provides numerous examples of Commission approval of O&M costs being included in approved riders and deferred accounting mechanisms.[22]

70. The Company also points out that Staff witness Camp, after being informed that all incremental O&M was incurred pursuant to contracts, stated that the concern of double recovery would be removed.[23]

71. The only support given by Staff for this disallowance is found in Mr. Camp's pre-filed testimony:

> Second, the Stipulating Parties recommend the Commission deny deferred accounting treatment for O&M activities that are incremental to those used to establish rates in the Company's last rate proceeding. This recommendation is consistent with the Commission's treatment for O&M expense incurred above and beyond what is included in base rate.[24]

72. During his cross-examination, Mr. Camp did not give specifics as to why the O&M should not be included in the deferred accounting, stating that he did not think it was "necessary."[25]

73. When pressed as to why O&M recovery through the deferred accounting mechanism is not necessary in the instant case, Mr. Camp stated:

> Well, one, I think the standard treatment is to bring forward these types of expenses in a rate case and then demonstrate that in a rate proceeding what's appropriate going forward. I think anything that the Commission would offer over and above ordinary course of treatment is extraordinary rate treatment. That's why I don't think it's necessary, considering that the Commission is essentially granting a presumption of prudence with regard to need for over $500 million worth of investment here.

[22] Public Service Statement of Position, p. 22.

[23] Hearing Transcript Vol. II, at pp. 62:25-63:6.

[24] Hearing Exhibit 503, pp. 25:19-26:2.

[25] Hearing Transcript, Vol. II, p. 63:6-7.

> So, I think the Commission has a lot of discretion from giving no extraordinary treatment up to what the Company has asked. And it's our opinion that it's not necessary to go as far as giving O&M treatment as far as cost recovery or deferred accounting.[26]

74. When pressed as to why deferred accounting is necessary in this matter, Mr. Camp indicated that the reason the Stipulation includes a deferred accounting treatment, yet there is reluctance to include O&M, was simple negotiations:

> Q: Why is it necessary to give deferred accounting, then?
>
> A: Well, one, I think we had -- I'm not sure that it's necessary. We wanted to move off of the position that we have in the answer case, at least from Staff's perspective.[27]

75. It appears that there is no real reason not to include the O&M expense, other than a position taken in negotiations. The undersigned ALJ is persuaded by the recent Commission decisions mentioned by Public Service and given that all incremental O&M was incurred pursuant to contract labor, which Mr. Camp testified would alleviate Staff's concerns of double recovery.[28]

76. In order to craft a decision which is both fair to ratepayers and creates an incentive for the utility, incremental O&M shall be included in the deferred accounting mechanism.

3. Carrying Costs

77. Public Service requests a carrying charge on the deferred account equal to its after-tax WACC, as authorized in its most recent Phase I rate case, Proceeding No. 19AL-0680E.

[26] *Id.* at p. 88:12-89:7.
[27] *Id*. at p. 89:8-13.
[28] *Id*. at p. 63:1-6.

Public Service does not request a return on the deferred account associated with distributed O&M.

78. Public Service maintains that the WACC is appropriate because it reflects the actual cost that Public Service will incur to finance the WMP investments. Additionally, Public Service states that as part of the Wildfire Mitigation Settlement approved by Decision No. C20-0096E, wildfire mitigation capital was placed into rate base, therefore the WMP investments at issue in this proceeding should also be allowed to earn the WACC.

79. The Intervenors recommend that Public Service be allowed a rate equal to its long-term cost of debt, also established in Proceeding No. 19AL-0680E, adjusted monthly. The Intervenors state that when Public Service files its next Phase I rate case, it will be able to incorporate its WMP investments into rate base, in which they can earn the WACC.

80. Staff and the OCC state that shareholders will benefit from the WMP through reduction of potential liability associated with a wildfire and will also benefit because the investments made in the WMP will add to rate base, leading to long-term shareholder profit. Staff states that it is reasonable to expect Public Service to help finance the investments because it will benefit from increased rate base and from decreased risk of wildfire-associated liability.

81. CEC states that allowing special cost recovery such as a deferred asset should be done only sparingly and that a return equal to the WACC would unreasonably reward Public Service. CEC notes that Public Service agreed to a deferred asset without any return in Proceeding No. 19A-0471E.

82. Public Service suggests the Commission look to other jurisdictions to see how cost recovery of wildfire mitigation measures could be handled, noting recent proceedings in Idaho and Oregon. Staff, the OCC, and CEC each note that while Idaho implemented a deferred

asset, no carrying charge was allowed on that regulatory account. Oregon has yet to authorize a recovery methodology, requiring additional "guardrails" to ensure that the investments are effective.

83. At hearing, Public Service witness Trammel stated that the Company will carry out its WMP, regardless of whether it is allowed special recovery for its investments through this proceeding. The WMP will benefit citizens of Colorado through decreased risk of wildfires, but it will also benefit Public Service's shareholders through decreased potential liability. And, the WMP "includes approval to proceed with roughly $458.5 million in capital investments,"[29] which will likely be included in Public Service's next rate base earning the WACC, further benefiting shareholders. The allowance of a return on the deferred asset at the cost of Public Service's long-term debt will recognize the benefit of the decreased wildfire risk resulting from the WMP. Public Service will benefit in the long term as its investments are incorporated into rate base.

84. In addition, the nature of the investments associated with the WMP are long-term investments consistent with long-term debt. Though a full analysis of debt and equity will be undertaken when a rate case is filed, long-term debt represents a conservative return amount that is appropriate in this situation to offset other factors such as single-issue ratemaking and Public Service's high degree of certainty of cost recovery in the next rate case.

85. Further, the Wildfire Mitigation Settlement approved by Decision No. C20-0096E addresses only the 2019 Distribution capital additions and 2019 Distribution and Transmission

[29] Staff Statement of Position, p. 3.

O&M, and specifically states that Public Service's 2020-2023 WMP will be addressed in a separate filing, whether as part of a Phase I rate case or separate application. The Wildfire Mitigation Settlement as approved sets no guidelines on what, if any, carrying cost shall be authorized for the 2020-2023 WMP.

86. Given that the investments made in the WMP will result in a significant increase to Public Service's rate base, and will be subject to the WACC when those investments are included in rate base in Public Service's next Phase I rate case, the Intervenors' recommendation that the deferred asset be afforded a carrying charge equal to Public Service's long-term cost of debt, is appropriate and will be granted. Denial of the Company's request for a carrying charge equal to its WACC strikes a balance between benefiting the ratepayers and providing an incentive to the Company.

C. Other Issues

1. Legal and Regulatory Expenses

87. Public Service requests that the Commission authorize the Company to defer to its next Phase I electric rate case the review, approval, and recovery of its legal and regulatory expenses incurred in litigating this proceeding.[30]

88. Public Service argues that it is not seeking recovery of legal and regulatory expenses through this proceeding but simply requesting authority to track and defer these expenses for consideration in a future rate case filing.[31]

[30] Public Service Statement of Position, p. 27.
[31] *Id*.

89. The Intervenors generally view this request as single issue rate making[32] and/or as providing too much of a benefit to the Company at the expense of the ratepayers.[33]

90. The undersigned ALJ agrees with the Intervenors. The deferral of legal expenses incurred in this proceeding does not speed up implementation of the WMP. Granting this request provides no benefit to the ratepayers, only to the Company. Granting the deferred accounting treatment is intended to show support for the program while also providing an incentive for the quick implementation of the WMP. Granting deferral of the legal and regulatory expenses would be counter to those goals and unjustly enrich the Company at the expense of the ratepayers.

2. Transmission Costs

91. All parties are in agreement concerning transmission costs.[34]

92. Prudently incurred capital costs associated with the transmission programs outlined in the WMP are recoverable through the TCA.

93. In its TCA filings, the Company shall identify wildfire capital for which TCA recovery is being sought and detail the amounts expended for each of the five (5) wildfire risk zones.

3. Key Performance Indicators

94. The parties also agree to the Key Performance Indicators as stated in the Stipulation. The following indicators are approved and adopted:

> Vegetation Management Maintenance Cycle: During each of the calendar years 2021 and 2022 Public Service will maintain vegetation around all distribution and transmission assets in the Company's identified Wildfire Risk Zone ("WRZ") on at least a 90 percent completion of cycle basis. As set forth below,

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[32] EOC Statement of Position, pp. 11-12.

[33] Hearing Exhibit 503, p. 26:4-14.

[34] Stipulation, p. 4; Public Service Statement of Position, p. 29.

the Company will provide annual reporting on this metric, including its progress on achieving the 90 percent targets.

Work Completion: During each of the calendar years 2021 and 2022, Public Service will complete 90 percent of its scheduled work annually as proposed in the Company's WMP. As set forth below, the Company will provide annual reporting on this metric, including its progress on achieving this target.

Work Completion Ratio (WCR): During the calendar years 2021 and 2022, Public Service will complete system hardening Repair/Replacement and System Protection programs to the percent of actual spend as compared to budget, across the entire WRZ, equal to or exceeding 0.900 and report the actual WCR by county in the WRZ. If the WCR is less than 0.900 then the Company will report WCR by system hardening program repaired or replaced for each county within the WRZ.

If these metrics are not achieved in a particular program year, the Company will provide detailed testimony and/or evidence explaining why it did not achieve the applicable target(s) at the time or times the Company seeks base rate cost recovery for distribution WMP costs and/or transmission WMP capital.

4. Reporting of Key Performance Indicators

95. The parties agree that the Key Performance Indicators will include the following metrics for each calendar year:

- The number of ignitions associated with electric overhead power lines within the WRZ;
- The number of downed transmission and distribution wires within the WRZ;
- The number of Red Flag Warning Days in Colorado;
- The communities or areas which experienced Red Flag Warnings, as well as the dates they occurred;
- The total number of wildfires in the Company's service territory;
- The annual WCR, as set forth in Section 2 above;
- The annual budgeted and planned distribution and transmission spend by WMP program for each county in the WRZ;
- The total actual annual distribution and transmission investment by WMP program for each county in the WRZ;

- Balances and monthly detail of the deferred accounts identified in Item 4 (Cost Recovery) above;
- The Company's progress on executing equipment upgrades, major line rebuilds, small conductor replacement, covered conductor, and overhead rebuilds with a summary of work completed and remaining work to be completed; and
- Percentage on-cycle vegetation management activities for transmission and distribution assets in WRZ.

96. The filings reporting the Key Performance Indicators shall be made annually in May in this proceeding. The first of these reports shall be filed within 45 days of a final Commission decision in this proceeding and shall cover the calendar year 2020.

5. Time Period for the Deferred Accounting Treatment

97. The deferral period begins January 1, 2021, with the depreciation expense for 2019 and 2020 capital additions to be included at the level of January 1, 2021, on a going-forward basis.

98. The deferral account treatment shall last three (3) years. It shall cover the years of 2021, 2022, and 2023.

99. The Company may defer monthly depreciation expense and interest associated with distribution capital placed into service through the term of the approved deferral (2021-2023).

VII. ORDER

A. It Is Ordered That:

1. The Wildfire Mitigation Plan (WMP) Application filed by Public Service Company of Colorado on July 17, 2020, is approved.

2. The WMP is supplemented by the reporting requirements stated above.

3. The Wildfire Protection Rider filed by Public Service Company of Colorado on July 17, 2020, is denied.

4. A deferred account mechanism is authorized for the years 2021, 2022, and 2023, as stated above.

5. A Technical Conference shall be scheduled after there is a final Commission decision in this proceeding. The parties shall informally contact the undersigned ALJ to schedule the Technical Conference.

6. This Recommended Decision shall be effective the day it becomes the Decision of the Commission, if that is the case, and is entered as of the Mailed Date above.

7. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a) If no exceptions are filed within 20 days after service or within any authorized extended period of time, or unless the decision is stayed by the Commission upon its own motion, this Recommended Decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, this proceeding is bound by the facts set out by the Administrative Law Judge.

8. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

(S E A L)

THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

ROBERT I. GARVEY

Administrative Law Judge

ATTEST: A TRUE COPY

Doug Dean

Doug Dean,
Director