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LEGAL SERVICES

Allegheny Energy
800 Cabin Hill Drive
Greensburg, PA 15601-1689
PH: (724) 838-6210
FAX: (724) 838-6464
jmunsch@alleghenyenergy.com
800 Cabin Hill Drive
Greensburg, PA 15601-1689
PH: (724) 838-6210

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INDEPENDENT REGULATORY
REVIEW COMMISSION

April 16, 2007

VIA FEDERAL EXPRESS

James J. McNulty, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: **Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 pertaining to adding Inspection and Maintenance Standards for the Electric Distribution Companies; Docket L-00040167**

Dear Secretary McNulty:

Enclosed please find an original and 15 copies of the Additional Comments of Allegheny Power with respect to the above-referenced matter. The Additional Comments are filed by Federal Express and the filing date is deemed to be today.

Very truly yours,

John L. Munsch

John L. Munsch
Attorney

Enclosures
cc Elizabeth Barnes (ebarnes@state.pa.us)

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SECRETARY'S BUREAU

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Proposed Rulemaking for Revision of 52 Pa. Code Chapter 57 pertaining to adding Inspection and Maintenance Standards for the Electric Distribution Companies	:	**Docket No. L- 00040167**

ADDITIONAL COMMENTS OF ALLEGHENY POWER

I. INTRODUCTION

Allegheny Power submits comments at the above-captioned docket in response to the Pennsylvania Public Utility Commission's ("Commission") January 9, 2007 letter announcing a technical conference and extension of the deadline for public comment to April 16, 2007. The associated Proposed Rulemaking Order was adopted by the Commission on April 20, 2006 and published in the Pennsylvania Bulletin on October 7, 2006. (36 Pa.B. 6097).

II. SUMMARY

Allegheny Power ("AP") participated in the Technical Conference held on January 22, 2007 and provides the following responses to: (1) questions posed to all EDCs by the Commission in its January 9, 2007 letter, (2) additional questions posed to Allegheny Power at the conference, and (3) OCA's and AFL-CIO's presentations and transcribed comments from the conference. The Commission's Proposed Rulemaking has the potential for far-reaching consequences and Allegheny Power appreciates the opportunity to provide additional comments.

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III. SPECIFIC COMMENTS

Allegheny Power provides the following comments and responses concerning the proposed Inspection and Maintenance (I&M) Standards:

A. Questions posed to all EDCs by the Commission in its January 9, 2007 letter.

- Does your company have a periodic I&M plan for each type of equipment listed above? If not, please explain why not. Provide specific explanations in your response for each type of equipment.

<u>AP RESPONSE</u>:

i. Allegheny Power has an I&M plan for each type of equipment listed.

- If your company does have a periodic I&M plan for the equipment listed above, please list the I&M cycles that are followed for each type of equipment.

<u>AP RESPONSE</u>:

i. Poles – Distribution poles are inspected on a 12-year cycle,

ii. Overhead conductors and cables – Transmission lines are aerially inspected once per year. Distribution lines are inspected on average every six years.

iii. Wires – Same as (ii) above.

iv. Transformers – Overhead distribution transformers are visually inspected as part of the distribution line inspection. Padmount transformers and below-grade transformers are inspected every five years.

v. Switching devices – Switches are visually inspected as part of the distribution line inspection.

vi. Protective devices – Cutouts are visually inspected as part of the distribution line inspection. Line reclosers are inspected and read once per year. Line reclosers are tested when they meet the manufacturer's recommended fault duty based on number of operations.

vii. Regulators – Regulators are visually inspected as a minimum once every five years.

viii. Capacitors - Capacitors are visually inspected every year.

ix. Substations – Substations are visually inspected three times per year. Additionally, condition-based inspection and maintenance activities occur throughout the year.

x. Other facilities critical to maintaining an acceptable level of reliability. – No further equipment to report.

➢ *An EDC shall maintain the following minimum inspection and maintenance intervals:*

1. *Vegetation management. The Statewide minimum inspection and treatment cycles for vegetation management are 4 years for distribution facilities and 5 years for transmission facilities.*

2. *Pole Inspections. Distribution poles shall be visually inspected every 10 years.*

3. *Overhead line inspections. Transmission lines shall be inspected aerially twice per year in the spring and fall. Transmission lines shall be inspected*

on foot every 2 years. Distribution lines shall be inspected by foot patrol a minimum of once per year. If problems are found that affect the integrity of the circuits, they shall be repaired or replaced no later than 30 days from discovery. Overhead distribution transformers shall be visually inspected annually as part of the distribution line inspection. Above-ground transformers shall be inspected on a 2-year cycle. Reclosers shall be inspected and tested once per year.

4. *Substation inspections. Substation equipment, structures, and hardware shall be inspected monthly.*

➢ For each of the four I&M intervals listed above, what are the I&M intervals utilized by your company?

<u>AP RESPONSE</u>:

1. Vegetation management.

   i. Distribution facilities – Unless governed by local agreements, AP performs vegetation management on distribution circuits on a three year or four year cycle, depending on local vegetation conditions. Included in the program is an off right-of-way hazard tree mitigation program.

   ii. Transmission facilities – AP utilizes a flexible approach to transmission line management of nine years for side trimming, six years for brush control, and three years for on right-of-way tree trimming. Aerial patrols determine the need to meet, accelerate, or delay these recommended cycles. Hazard trees are located during aerial patrols and removed as they are discovered.

2. Pole Inspections.

i. Distribution poles – Distribution poles are inspected on a twelve year cycle.

3. Overhead line inspections.

   i. Transmission lines - Transmission lines are aerially inspected once per year on a general patrol and comprehensively inspected once every 5 years for 345-500 kV or once every 10 years for 115-230 kV.

   ii. Distribution lines - Distribution lines are inspected every six years.

   iii. Problems found – Problems found during inspection are corrected according to the critical nature of the problem. For instance, danger poles are replaced or secured within 5 working days of notification. Reinforceable poles are reinforced during the inspection year. Regular reject poles are replaced the following year. Any safety-related problems are addressed immediately. It is generally more productive to schedule non-critical work in the following year to adequately allocate budget and manpower resources. Any problems discovered on a transmission line would need advance scheduling approval for maintenance from PJM, which may require a lead time of months.

   iv. Overhead distribution transformers - Overhead distribution transformers are visually inspected as part of the distribution line inspection on average every six years.

v. Above-ground transformers - Padmount transformers are inspected every five years.

vi. Reclosers - Line reclosers have counters read annually and are tested when they meet the manufacturer's recommended fault duty based on number of operations.

4. Substation inspections.

i. Substations are visually inspected three times per year. Additionally, condition-based inspection and maintenance activities occur throughout the year.

➢ For each of the four I&M intervals, what is an estimate of the annual cost to convert from your company's interval to those proposed above?

AP RESPONSE:

1. Vegetation management – $4.9 million
2. Pole inspections – $0.7 million
3. Overhead line inspections – $3.63 million plus initial set-up costs of $1.5 million for increased recloser inventory.
4. Substation inspections - $0.9 million

➢ If the Commission were to adopt the edited Annex A version in the AFL-CIO's comments dated November 4, 2006, what would those changes to the regulations cost Pennsylvania ratepayers? Please justify an aggregate figure with specifics. Would the proposed additions to the proposed regulations better reliability performance in the EDC industry?

AP RESPONSE:

1. AP estimates that the AFL-CIO's proposed changes would cost the company $8.0 million in addition to those costs identified in the preceding question. These costs include:
    a. $0.6 million for additional inspection as a result of 5 or more circuit trips, regardless of the cause.
    b. $1.7 million for underground vault infrared scanning
    c. $1.3 million annual switch testing
    d. $1.1 million for annual substation circuit breaker testing
    e. $1.9 million for testing group operated switches
    f. $0.8 million for relay inspection and testing
    g. $0.6 million for underground transformer load calculation
2. AP believes that the additional inspection and maintenance activities proposed would significantly increase costs while at the same time do little to increase overall reliability. Many of the testing procedures either require outages or provide additional opportunities for outages while equipment is removed from service for testing and maintenance. Money and manpower resources are potentially diverted away from maintaining critical upstream equipment in favor of more non-critical downstream components. Resources are also expended on equipment that otherwise would not need maintenance under the current reliability-centered maintenance program. Additional testing of equipment shown under a reliability-centered maintenance program to not need maintenance will not increase reliability.

- If the Commission were to adopt minimum repair standards and time frames for corrective actions, what would your EDC recommend they be?

AP RESPONSE:

1. The minimum repair time frames would depend on the critical nature of the correction needed. In general, any action is better implemented if a suitable planning period is allowed to allocate funds and manpower. Any safety-related issues should be (and currently are) resolved immediately. Lesser critical repairs are planned in the current year and non-critical repairs are planned in the next budget cycle similar to AP's pole program mentioned earlier.

- Do you have any criticisms of the OCA's proposed revision to Annex A, and if so, what would they be? What would the cost be to ratepayers if any in implementing the proposed regulations in Annex A as revised by OCA? What would the benefit be?

AP RESPONSE:

1. Additional equipment testing, intrusive inspections, and distribution transformer load calculations provide little reliability benefit, add significantly to costs, and may provide additional opportunities for customer outages that would not have existed otherwise. Intrusive inspections can be risky because they require knowledge of specific equipment construction to return the

equipment to design conditions without introducing potentially new failure modes.

2. AP's additional costs are estimated to be $11 million over and above PUC's base proposals. The major additional costs consist of overhead and underground transformer load calculations ($3.7 million), line switch testing ($1.3 million), intrusive inspections of substation distribution transformers ($1.5 million), substation switch testing ($1.9 million), relay testing ($.83 million), infrared scanning of distribution lines ($0.4 million), and substation breaker diagnostic testing ($1.0 million).
3. As mentioned previously, minimal additional benefits are anticipated from performing unnecessary maintenance on equipment. Reliability could be adversely affected as additional opportunities for customer outages are presented by intrusive inspections and switching out good pieces of equipment.

➢ What are your objections, if any, to a 4-year tree trimming cycle for distribution lines? Would you accept a 5 or 6-year tree trimming cycle? Would you prefer an average tree-trimming cycle as proposed by Duquesne Light?

AP RESPONSE:

1. A four-year tree trimming cycle would be acceptable.
2. AP prefers a periodic cycle for each line as compared to an average cycle.

B. Additional questions posed to Allegheny Power at the January 22, 2007 Technical Conference

- Ms. Barnes: And could you tell me how you calculate your minimum vegetation clearance increase of $4.1 million? Do you also use the line mileage?

AP RESPONSE:

- The anticipated additional vegetation clearance costs would result from a significant increase in trimming costs and more frequent inspections on distribution lines to maintain a set minimum clearance. Although a minimum clearance has not been set, extra patrols and trimming would be required to monitor for any minimum clearance standard. Line mileage is used to calculate the increase in vegetation management of $4.1 million/year. This amount includes $2.8 million for trimming and $1.2 million for inspection. It assumes over 19,000 miles per year at about $60/mile to inspect and $150/mile to trim.

- Mr. Young: Because if we're going to focus the inspection and maintenance standards, just knowing the number of outages is only part of the equation. We need to know the total time, because if the total time of substation outages was 50% of your outages, the fact that it only affected one percent of your outages is.... Mr. Mattiuz: Okay, so you're talking in terms of SAIDI? Mr. Young: Yes.

AP RESPONSE:

- AP provided a response to this question in its February 21, 2007 responses to the Commission's information request and is provided below as information:

The table below shows the relevant percentages of Allegheny Power's Pennsylvania Customer Interruptions (CI) and Customer Minutes Interrupted (CMI), for each of the items mentioned in Allegheny Power's Powerpoint presentation for the January 22nd, 2007 Technical Conference. All data in this table is based on 2003-2006 outage data. Please note that any discrepancies are due to the fact that complete 2006 data was not available at the time the original percentage estimates were calculated.

	Data Provided at Technical Conference		Analysis of 2003-2006 Data	
	Page Reference	Percentages Cited	Frequency *(Customer Interruptions)*	Total Duration *(Customer Minutes Interrupted)*
Transmission (100kV and Above)	Pages 3,8	No CI in 2006, Less than 1% of CI	0.6%	0.5%
Substation-Related	Pages 4,8	1% - 2% of CI	1.7%	1.3%
Distribution	Pages 5,8	97% - 98% of CI	97.7%	98.1%
Reclosers	Page 5	1% of CI	1.3%	0.9%
Overhead Transformers	Page 5	1% - 1.5% of CI	1.1%	1.1%
Poles	Page 5	0.8% of CI	0.6%	0.8%
Underground Transformers	Page 5	0.25% of CI	0.1%	0.3%
Equipment-Related Causes	Page 5	30% of CI	29.2%	22.2%

Note: "CI" is shorthand for "Customer Interruptions".

- Mr. Young: And, for example, what type of technology? Mr. Mattiuz: I would say distribution monitoring, for example, where we're actually able to do a lot of monitoring on our distribution system as far as, while we're having good monitoring on our transmission system, on our distribution system the investment would be more on knowing that you have customer outages on the system versus having the customer call in to notify us that they're out. Mr. Young: A SCADA type system? Mr. Mattiuz: Right, exactly. Now, if the company has a different opinion, that will be included in our comments.

AP RESPONSE:

- o AP has no further comments.

C. Rebuttal responses to OCA's and AFL-CIO's presentations and transcribed comments from the conference

- ➢ AFL-CIO presented a chart showing AP's SAIDI for 1994, 1999, and 2005 and stated "The lack of these standards over the last ten years has had a serious impact on reliability in Pennsylvania.... We can see Allegheny Energy, the average outage length increased by more than an hour since 1994...."

AP RESPONSE:

As the Commission and AFL-CIO are aware from AP's reliability proceeding in M00991220F2003, AP's reliability statistics pre-2001 were artificially low compared to current statistics due to implementation of an automated outage management system. AP's SAIDI at the end of February 2007 was 209 minutes. This does not differ significantly from a 1991 to 1995 average of 1.06 SAIFI recognized in the proceeding as an OMS-adjusted statistic times a CAIDI of 180 or a SAIDI of 191. AP is within range of its settlement benchmarks & PUC standards negotiated with interveners to the.

- AFL-CIO further states that "They've *(EDCs)* adopted "run until failure" maintenance practices which essentially means they've eliminated preventive maintenance which jeopardizes the safety and reliability of their systems and increases long-term costs."

AP RESPONSE:

AP strongly disagrees with this assertion. As evidenced by its programs provided to the Commission, AP inspects and maintains its equipment on cycles according to its criticality to overall system reliability. Transmission and substation equipment, due to its critical nature serving thousands of customers, is inspected and maintained on a more frequent basis than a distribution transformer, for example, serving several customers. 'Run-to-failure' may be a strategy for some inexpensive, long lasting, non-critical, difficult to test equipment such as distribution transformers; whereas, it is not a consideration for transmission and substation equipment. Analogous to a vehicle, tires and brakes are typically inspected on a periodic basis and replaced before failing due to their critical nature to safety and reliability, but a battery or alternator are typically run-to-failure components.

- OCA indicates in its comments that minimum transmission and distribution inspection and maintenance standards are necessary due to the August 2003 Blackout.

AP RESPONSE:

AP's transmission and substation outages account for a very small percent of customers interrupted, due in part to the successful implementation of its current inspection and maintenance practices. FERC has addressed inspection and maintenance along interstate transmission corridors. The August 2003 Blackout root cause has been addressed by FERC, and they will continue to address any other emerging problems that occur on the transmission system. OCA implies that distribution inspection and maintenance standards are of equal importance to transmission. While each transmission outage has a much larger effect on reliability statistics, AP agrees that equipment-related outages on the distribution system are also very important and need to be minimized. For this reason, AP already has programs to inspect and maintain distribution equipment as previously provided to the Commission. OCA has not provided information, however, that suggests that different distribution systems, with different terrain, tree species and coverage, technology application, age, and reliability root causes should have identical, inflexible, calendar-based inspection and maintenance programs, in contradiction to the industry move to reliability-based practices.

IV. CONCLUSION

Allegheny Power believes that, contrary to OCA's assertion, establishing minimum inspection and maintenance standards while calling for detailed inspection, maintenance, and repair plans individual to the EDC's territory plus Commission-enforced benchmarks and standards does not allow for needed flexibility and opportunities for innovation as technology develops. By diverting critical resources from investing in circuit automation or equipment upgrades to inspecting distribution transformers, customers are not benefiting from improvements in reliability.

Respectfully submitted,

WEST PENN POWER COMPANY
d/b/a ALLEGHENY POWER

By: John L. Munsch
John L. Munsch
Senior Attorney
Pa. Attorney No.: 31489
800 Cabin Hill Drive
Greensburg, PA 15601
724-838-6210

Dated: April 16, 2007