Oregon

Theodore R. Kulongoski, Governor

Public Utility Commission
550 Capitol St NE, Suite 215
Mailing Address: PO Box 2148
Salem, OR 97308-2148
Consumer Services
1-800-522-2404
Local: (503) 378-6600
Administrative Services
(503) 373-7394

May 1, 2006

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: **OPUC Docket No. AR 506** - In the Matter of a Rulemaking to Amend and Adopt Permanent Rules in OAR 860 Divisions 24 and 28 Regarding Pole Attachment Use and Safety.

Enclosed for filing in the above-captioned docket is the Public Utility Commission's AR 506 Staff Division 024 Comments. As a courtesy, the interested persons identified on the Commission's service list were also provided an electronic copy of these documents.

/s/ Diane Davis

Diane Davis
Regulatory Operations Division
Filing on Behalf of Public Utility Commission Staff
(503) 378-4372

CERTIFICATE OF SERVICE

AR 506

I certify that I have, this day, served Division 24 Comments of Oregon PUC Staff, May 1, 2006, upon all participants of record in this proceeding by electronic mail as indicated on the attached service list.

Dated at Salem, Oregon, this 1st day of May, 2006.

/s/ *Diane Davis*
Diane Davis
On behalf of the Staff of the
Public Utility Commission of Oregon

MATT COONS matt.coons@comspanusa.net	**HAROLD LEAHY & KIERAN** CHRISTY MONSON ckm@haroldleahy.com
JIM DEASON ATTORNEY AT LAW jimdeason@comcast.net	**MCMINNVILLE CITY OF WATER & LIGHT** SCOTT ROSENBALM sgr@mc-power.com
ASHLAND CITY OF SCOTT JOHNSON johnsons@ashland.or.us	**LEAGUE OF OREGON CITIES** ANDREA FOGUE afogue@orcities.org
CENTRAL LINCOLN PUD DENISE ESTEP destep@cencoast.com MICHAEL L WILSON mwilson@cencoast.com	**IDAHO POWER COMPANY** JEANNETTE C BOWMAN jbowman@idahopower.com TOM WICHER twicher@idahopower.com
CENTURYTEL OF OREGON INC DOUG COOLEY doug.cooley@centurytel.com	**MILLENNIUM DIGITAL MEDIA** EUGENE A FRY gfry@mdm.net
CHARTER COMMUNICATIONS CORP GARY LEE glee@chartercom.com	**MILLER NASH LLP** BROOKS HARLOW ATTORNEY brooks.harlow@millernash.com
CLEAR CREEK MUTUAL TELEPHONE CO BILL KIGGINS bkiggins@clearcreek.coop	**MONMOUTH CITY OF** JIM HOUGH jhough@ci.monmouth.or.us
CN UTILITY CONSULTING STEPHEN R CIESLEWICZ steve@cnutility.com	**MONMOUTH, CITY OF** DAVE WILDMAN dwildman@ci.monmouth.or.us
COLE RAYWID & BRAVERMAN LLP SCOTT THOMPSON ATTORNEY sthompson@crblaw.com	**NIPPC** SUSAN K ACKERMAN ATTORNEY susan.k.ackerman@comcast.net
COMSPANUSA SEBASTIAN MC CROHAN sebastian.mccrohan@comspanusa.net	**OREGON CABLE AND TELECOMMUNICATIONS ASSOCIATION** MICHAEL DEWEY mdewey@oregoncable.com
CONSUMER POWER INC STUART SLOAN stuarts@cpi.coop	**OREGON JOINT USE ASSOCIATION** GENOA INGRAM genoa@westernadvocates.com JOHN SULLIVAN john.sullivan@pgn.com WILLIAM C WOODS william_woods@cable.comcast.com
DAVIS WRIGHT TREMAINE SARAH K WALLACE ATTORNEY AT LAW sarahwallace@dwt.com	**OREGON MUNICIPAL ELECTRIC UTILITIES ASSOC** TOM O'CONNOR toconnor@teleport.com
DEPARTMENT OF JUSTICE MICHAEL T WEIRICH ASSISTANT ATTORNEY GENERAL michael.weirich@state.or.us	**OREGON PUD ASSOCIATION** DON GODARD dgodard@opuda.org
ELECTRIC LIGHTWAVE LLC CHARLES L BEST ATTORNEY AT LAW charles_best@eli.net	**OREGON RURAL ELECTRIC COOPERATIVE ASSN** JACK EVANS jevans@oreca.org

EMERALD PUD CRAIG ANDRUS craig.andrus@epud.org	**OREGON TELECOMMUNICATIONS ASSN** BRANT WOLF bwolf@ota-telecom.org
ESCHELON TELECOM OF OREGON INC CATHERINE A MURRAY camurray@eschelon.com	**PACIFIC POWER & LIGHT** CECE L COLEMAN cece.coleman@pacificorp.com COREY FITZGERALD corey.fitz-gerald@pacificorp.com
PORTLAND CITY OF - OFFICE OF TRANSPORTATION RICHARD GRAY richard.gray@pdxtrans.org	**PORTLAND GENERAL ELECTRIC** DAVID P VAN BOSSUYT dave.vanbossuyt@pgn.com
PRIORITYONE TELECOMMUNICATIONS INC kmutch@p1tel.com	**QWEST** JEFF KENT jeffrey.kent@qwest.com
QWEST CORPORATION ALEX M DUARTE alex.duarte@qwest.com	**SALEM ELECTRIC** ROGER KUHLMAN kuhlman@salemelectric.com
SPRINT COMMUNICATIONS CO LP BARBARA YOUNG barbara.c.young@mail.sprint.com	**TIME WARNER TELECOM OF OREGON LLC** BRIAN THOMAS brian.thomas@twtelecom.com
VERIZON STEVEN LINDSAY steve.lindsay@verizon.com	**VERIZON NORTHWEST INC** RICHARD STEWART richard.stewart@verizon.com RENEE WILLER renee.willer@verizon.com
WANTEL INC MARTY PATROVSKY marty.patrovsky@comspanusa.net	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 506

In the Matter of a Rulemaking to Amend and Adopt Permanent Rules in OAR 860, Divisions 24 and 28, Regarding Pole Attachment Use and Safety.	))))	DIVISION 24 COMMENTS OF OREGON PUC STAFF MAY 1, 2006

AR 506 - OPUC STAFF FIRST ROUND COMMENTS – DIV. 24

TABLE OF CONTENTS

Item	*Page*
Executive Summary o General Background and Staff Perspective o Comments on OAR 860-024-0011 o Issues 3 & 10 o Issue 7 o Closing Statements	 1 through 3. 5 and 6. 9 and 10 (first two paragraphs) 17 through 19 22
General Background & Staff Perspective	1 through 3
Comments on OAR 860-024-0001 – Definitions	3 and 4
Issue 11	**3**
Comments on OAR 860-024-0011	5 and 6
Issue 12	6 and 7
Issue 1	3 and 4
Issue 2	7
Issue 4	7 and 8
Prioritizing of Repairs – OAR 860-024-0012	8 through 15
Issues 3 and 10	9through 14
Issue 13	14 and 15
Overall Staff Recommendation for OAR 860-024-0012	15
Duties of Structure Owners – OAR 860-024-0014	15 through 17
Issues 5 and 6	15 through 17
Vegetation Clearance Requirements – OAR 860-024-0016	17 through 21
Issue 7	17 through 20
Issue 7 (City of Portland)	20
Issue 8	20 and 21
Issue 9	21
Vegetation Management Conclusions	21
Issue 14	22
Closing Statements	22
Staff Education and Employment Summaries	Exhibit 1 (1 page)
NESC History	Exhibit 2 (5 pages)
27 year serious injury electrical contact history	Exhibit 3 (1 page)
Line Inspection Requirement Policy	Exhibit 4 (2 pages)
Service Quality Measures for PGE and PP&L	Exhibit 5 (45 pages)
Vegetation Clearance Policy	Exhibit 6 (4 pages)
Tree Related Injuries with Power Lines	Exhibit 7 (1 page)
Children in Trees Injured on Power Lines	Exhibit 8 (1 page)
ODF Power Line Caused Fires	Exhibit 9 (1 page)
Power Line Injury Report	Exhibit 10 (28 pages)
Stipulated Agreements and Commission Letters	Exhibit 11 (18 pages)
Provisions for Joint-Use of Poles Policy	Exhibit 12 (2 pages)

AR 506 Staff First Round Comments

1. General Background & Staff Perspective

Chapter 860, Division 24 is a section of the Public Utility Commission of Oregon's (OPUC or Commission) administrative rules devoted to utility safety. The Division 24 rules have a substantial influence on the Oregon energy and communication utility industries from the perspective of protecting citizens, both workers and the public.

OPUC Safety Staff would like to provide their perspective on key elements within the proposed rulemaking. The electric safety Staff of the OPUC is uniquely qualified to comment in this rulemaking because of our extensive experience working both as utility employees and as OPUC employees, and because we are not biased by any financial motivation when recommending minimum safety standards. Every person in our section (electric and communication safety) has worked within the industry being regulated, and the five person team has approximately 170 years of cumulative utility-related work experience. We have experienced many of the tasks as a utility ground man, lineman, engineer, or manager, as well as employees for the OPUC. We have personally experienced and investigated injury accidents and seen the results of differing methods of maintaining and operating utility systems. We have acted as the administrative authority in Oregon for the National Electric Safety Code (NESC), adopting, enforcing, and interpreting this utility safety standard and participating on the national committee. Two members of our team have been working with Oregon utilities in this function since the early 1980's. Two more joined Staff in the late 1990's after long utility careers. See Exhibit 1 (for Staff education and employment summaries). Staff has a practical perspective on what will work and what will not. While compromise between parties properly characterizes many of the cases handled by the Commission, minimum safety standards have no room for compromises without affecting personal safety. These rules must be practical, but most importantly must ensure that established national and state levels for safety are maintained.

A significant consideration in this rulemaking must be Oregon's long standing legal adoption of the NESC. In 1923 the OPUC adopted most of the 3rd edition and "any subsequent changes, modifications, or alterations in such code." This code was developed in the early 1900's because widely varying line construction practices resulted in many injuries to the public. Electrical utility workers experienced about a 50% fatality rate in the workplace. Oregon was one of the first states to officially adopt this national code as a required safety standard. Please refer to the History of the NESC in Exhibit 2.

This NESC standard was significantly reinforced by the Oregon Legislature in 1975, when the OPUC was ordered to exercise its ORS 757.035 powers to "adopt by rule as the standard of such construction, operation and maintenance the 1973 edition of …..National Electrical Safety Code, C2." ORS 757.035(2) Under the direct authority of ORS 757.035(3) the Commission has adopted every subsequent edition of the NESC since that time, eight editions (now 2002), into OAR 860-024-0010. This Commission has also seen fit to include field personnel in its Staff that have enforced this standard for the past 25+ years.

Another consideration in this rulemaking is the years of statistics resulting from the rule requirement (adopted in 1974) to report specific utility accidents or incidents. See OAR 860-24-0050. We believe it is unique among the 50 states that only Oregon collects statistics and reports on all utility related electric contact injuries, including members of the public, general workers, and utility workers. As Staff continues to record, investigate, and report on these accidents each year, the statistics provide reinforcement of the need for practical safety standards and education. The 27-year (ending with 2005) average number of serious injury electrical contacts with utility facilities in Oregon is 24.9 people injured per year. This statistic emphasizes the need to continue to improve safety conditions along the utility rights-of-way statewide. See Exhibit 3.

In recent years (and compounded by the Telecommunication Act of 1996) significant changes have resulted from many new operators adding their facilities to the overhead and underground utility systems in many areas of Oregon. What started with two utilities sharing poles now is as many as eight operators on some structures. These changes have occurred because of competitive services, new technology integration, and the rapid deployment of low-cost facilities. The very limited utility rights-of-way are now crowded in urban and many suburban areas resulting in higher costs, increasing conflicts between operators, and a greater need for uniform construction and maintenance standards to preserve safety. This rulemaking directly addresses some of these needs.

Staff included a list of general “areas of concern” with its public meeting memo that requested the Commission open this docket. Subsequently, the Oregon Joint Use Association (OJUA) and the City of Portland submitted their proposed issues lists. However, the Administrative Law Judge (ALJ) has not officially adopted an Issues List for this docket. As such, Staff will organize its comments by addressing each proposed rule in sequential order, including a discussion of the various issues as identified by OJUA and the City of Portland under the appropriate proposed rule. Further, when reference is made to the “OJUA comments,” staff means the informal comments and positions the OJUA presented in the workshops leading to the current docket.

2. Comments on OAR 860-024-0001: Definitions for Commission Safety Rules

Issue 11: Wordsmithing of Definitions

The definitions are integral with the rules. Changing the definition does change the meaning of any rule that uses the word or term. Also, some words or terms are defined in other somewhat related portions of OPUC administrative rules such as Divisions 023 and 028, and to the degree appropriate, should be consistent to avoid confusion.

ISSUE 11 STAFF RECOMMENDATION: Staff recommends minimizing any changes to established or proposed definitions. Where unavoidable, changes should be considered carefully in context with its use in these rules and other related rules.

Issue 1: Defining a “Pattern of Non-Compliance”

This term is also found in OAR 860-028-0020 (11) related to pole and conduit attachment rules. There the term is intended to be broader to include contractual and permit specifications, as well as Commission Safety Rules. It would be a distinct advantage if there was no confusion with differing definitions in these rules which apply to the same group of operators.

The proposal by OJUA in the informal portion of this rulemaking unacceptably changes the intent of the rule itself. The scope of the rule is changed by eliminating all of the Division 024 rule requirements, except for the NESC. The addition of the concept of "material" only adds another somewhat fuzzy hurdle to overcome to substantiate a repeated failure to comply with the safety rules. Finally is the double requirement that to prove a "pattern of noncompliance" requires violations to be "documented by the PUC" and for violations to be "undocumented by the operator". Simply stated, if the offending operator has a record of the violations, no matter how bad the offenses, the Commission could not require any type of accelerated program be employed to speed protective repairs. Also, the pole owner or another joint use operator could not utilize their records to provide evidence that repeated offenses had been occurring. Each of these changes runs counter to the straight forward intent of the Commission being able to require a repeat offender to perform an accelerated inspection and correction program in order to catch-up with what should have been done to provide system safety.

The term is used only once in Division 24 in rule 0011(1)(d), where the last sentence reads; "Where facilities are exposed to extraordinary conditions or where an operator has demonstrated a pattern of noncompliance with Commission Safety Rules, the Commission may require a shorter interval between inspections." The term "pattern of non-compliance" has been controversial for many years, going back to an earlier rulemaking when the sanction rules were developed. With this perspective, Staff would propose that this last sentence in rule 0011(1)(d) be altered to; "The Commission may require shorter inspection intervals." This eliminates any need for the definition at issue in Division 24, and should eliminate needless debate on this issue. As a practical matter, any party may bring before the Commission a request to order a shorter inspection interval for an operator, and would have to make a case to convince the Commission of that need. This will also eliminate any confusion with different definitions.

ISSUE 1 STAFF RECOMMENDATION: Staff recommends that the definition for "Pattern of noncompliance" be removed, and that the last sentence of rule OAR 860-024-0011(1)(d) be changed to: "The Commission may require shorter inspection intervals."

3. Comments on OAR 860-024-0011

Inspections and Compliance of Electric Supply and Communication Facilities

The Oregon requirement (statute and rule) is for utility operators to have systems that comply with the NESC. The NESC requires "All electric supply and communication lines and equipment shall be designed, constructed, operated, and maintained to meet the requirements of these rules" (Rule 012A). The rule places the responsibility for meeting applicable requirements on the utilities, their authorized contractors, or other entities who perform the design, construction, operation or maintenance of the system (Rule 012B).

The responsibility for compliance is clear. Also, Rule 214 states that all newly constructed lines and equipment "shall comply" when placed in service, and all existing lines and equipment require periodic inspections "at such intervals as experience has shown to be necessary."

As Safety Staff performed inspections in the early 1980's there were numerous observations of deferred maintenance and NESC violations. It was commonplace to discover very bad poles and cross arms or lines burning on tree foliage all across Oregon. Early pole testing programs by utilities across the state routinely discovered 10% to 15% of their supporting structures were weak from various causes, and did not meet NESC minimum strength requirements and had to be replaced. Portland had an extensive dual system that had never been rebuilt as was promised when it had been divided between PGE and PP&L. These were areas where two complete electrical systems provided customers a choice for their service. These systems were rife with NESC violations and extensive deferred maintenance. Staff identified another area of Portland that required an extraordinary repair program because of extensive deferred maintenance and NESC violations. In this "D-11" area (a 12-square mile geographical location in the west hills identified by the township and range designation) there were many disputes between the operators and even the ownership of some very bad poles was uncertain. It is critical in this rulemaking that existing standards be maintained so Oregon never goes back to those types of unsafe conditions caused by deferred maintenance and ignoring NESC requirements.

In 1987 Staff participated in a collaborative process with industry to establish a practical policy to achieve compliance with the Rule 214 (Inspection and Tests of Lines and Equipment) requirements for line inspection. In 1989 the policy was revised to address industry concerns that the inspections would eventually be too frequent. This policy (see Exhibit 4), which has been in place for approximately 15 years, forms the basis for proposed OAR 860-024-0011. Staff's experience in the industry helped in drafting the requirements for the "detailed" inspections, and we believe they are a practical and reasonable approach, requiring each electric and communication operator to inspect approximately 10% of their systems annually, on a cyclic basis. Over time, if good quality inspections are done, repairs promptly effected, and any new construction built to code requirements, then repair work will diminish and reliability and safety will improve.

As stated earlier, PUC inspections in the 1980's focused on many items that were a hazard to life and property, such as bad poles and cross arms. More recently, Staff has been able to address the broader concern of NESC compliance, since the extreme cases of deferred maintenance have been addressed. The number of existing violations will continue to decrease and the costs will also decrease, while system safety will improve under Staff's proposal. The NESC is intended as a practical and achievable utility safety standard. Staff's objective is to just continue with existing programs as they achieve their practical objective of safety at reasonable and progressively lower costs.

Issue 12: Should "Compliance" be in the title?

The purpose of the system inspections is to evaluate and achieve compliance with a variety of federal, state, local (County and City), contractual, and company requirements. To inspect without taking any corrective action when problems are found is of little or no value. The intent of this rule is to set minimum standards for the NESC part of this process. Also, within these rules, compliance is specific in (1)(a), non-compliance is in (1)(d), and compliance is the subject of (1)(f) where records of the whole process (including Rule 0012 compliance repairs) are required. While compliance repairs are more specific in Rule 0012, the concept of minimum requirements to achieve compliance is common to both rules. While a rule title does not have requirements like the rule does, it should guide the reader to the appropriate portion.

ISSUE 12 STAFF RECOMMENDATION: Staff recommends the word "compliance" remain in this title.

Issue 2: Training of Employees and Contractors Required

In OAR 860-024-0011(1)(b) and (c) there is a requirement for employees and contractors to be trained for all tasks they will perform (somewhat similar to OSHA but specific to OPUC Commission Safety Rules for this industry). These rules were proposed by the industry. The OJUA has emphasized this need and has put on successful training programs annually for the past five years. Specifically, all workers must be trained for the tasks they will perform to ensure the safety of the public, other line workers, and themselves by complying with the NESC and other applicable Commission Safety Rules. These rules are intentionally not specific as to any certificate requirements, and are intended only to encode the employer's requirement to train their employees. While the rule is new, this training should already be provided. Staff does not understand the recommendation of the OJUA to delete these rules in the perspective of previous comments and actions.

ISSUE 2 STAFF RECOMMENDATION: Staff recommends that the training requirement be included in these rules.

Issue 4: Coordination of Inspections by Joint-Users

A change from previous requirements is to mandate coordination of inspection areas so that all joint users would inspect the same areas each year. This coordination should result in efficiency gains by combining inspection and repair activities and result in NESC-compliant areas. Because the state is already divided into established electric service territories, having each of those operators identify the areas to be inspected is the most workable solution proposed to date. The proposed rule requires the electric operator to publish the areas, and requires all joint-users within that area to do the detailed inspection covering the area in the assigned year. The opportunity to combine this work remains optional, but many operators will see the advantages. While there could be some uneven year-to-year work loads for attachers, this still is the best coordination plan thus far. This coordinated approach also works well for Safety Staff that can inspect these cleaned-up areas for NESC compliance very efficiently.

There are problems with uncoordinated inspection programs. There is a lot of inefficiency when there are numerous trips to the same pole to do separate inspections and then separate repair crew visits for every operator on the pole. Some violations are never corrected because operators blame each other for causing the problem. Therefore it is the other guy's responsibility to do the correction. Most significantly, it is a situation where no areas are ever completely cleaned up. The inspection and correction programs have been required since the late 1980's, with some operators on their third cycle of inspection and repairs, and still there are many uncorrected violations. While the lack of coordinated inspections and repairs is not the only cause of this, it is a contributing factor that should be changed.

These inspection plans described in Rule OAR 860-024-0011, carefully done, including prompt repairs, are essential to safety. The systems must be in good repair and have required heights, strengths, and inaccessibility for public safety. Utility workers require a uniform work environment, easily accessed, and with no hidden dangers or deterioration, if they are to be safe. With the careful detailed inspection performed only once every 10 years, it must be done well and must correct all marginal items on a timely basis and without fail.

ISSUE 4 STAFF RECOMMENDATION: Staff recommends that the requirements related to coordinating detailed inspections found in proposed rules OAR 860-024-0011(1)(d) and (2)(a) not be changed.

4. OAR 860-024-0012: Prioritization of Repairs…

As a preliminary matter, the Commission will need to consider whether the rules will impact Portland General Electric or PacifiCorp in light of the requirements of the Service Quality Measures (SQMs) which are stipulated agreements adopted under Commission Orders (PGE – Orders 97-196 and 05-1250 / PP&L – Orders 98-191, 99-616, and 03-528). The SQMs were adopted, modified, and extended in various cases and were deemed to have a benefit to ratepayers by the multiple parties involved. The stated purpose of the SQMs is "to provide a mechanism to ensure service quality is maintained at current or improved levels……." The inspection and repair programs are specified in the X2 Measure. These two electric utilities serve over 70% of Oregon's electric customers. See exhibit 5. Staff recommends the Commission conclude the SQMs will take precedence over the Rules so long as the SQMs are in effect. Staff intends to discuss these matters with PGE and PacifiCorp during the upcoming workshops.

Issues 3 and 10: What is the priority and timing of corrective work for facilities to be brought into compliance with the NESC? Does the cost benefit analysis justify the proposed rule?

The "prioritization of repairs" has been controversial. It is clear to Staff that Oregon statutes, OPUC Rules, and the NESC itself all require compliance with the NESC for electric and communication facilities. This rule forces a decision to comply with the NESC requirement or to accept a partial compliance alternative where each utility operator can decide which violations pose a hazard, and if and when it may be appropriate to fix them. Staff believes that stretching the inspection program beyond the 10-year schedule or not promptly correcting identified violations fails to meet the requirements of Oregon Law and the intent of the NESC. We see a similar approach taken by others in Oregon such as Building Codes (Uniform Building Codes and National Electrical Code for electricians, Plumbing Code, Heating and Air Conditioning Codes, etc.) OROSHA, and the OPUC administration of the Federal Gas Pipeline Safety program. In each case there is a standard established, and personnel assigned to assure compliance for the protection of our citizens. The rules in each case are mandatory and not subject to evaluation and multiple options.

The OJUA proposal allows each operator to assign a hazard value (really a non-hazard value) to NESC violations. Thus, the argument is not about the code requirement, but rather about the violation not really being any hazard if left uncorrected for a long or agreeably optional (under the "plan of correction" provision) time. Obviously, if every operator can have their individual list of NESC violations that are not deemed hazardous, and therefore do not really need to be in compliance, then Oregon's standard is no longer the NESC. This approach also makes any meaningful oversight and enforcement impossible. All rules in the NESC are safety rules, and provide the minimum standard for safety in the design, construction, operation and maintenance of the utility system, and the NESC is the Law in the State of Oregon.

To be reasonably consistent with Oregon statutes and long standing OPUC rules and policies, the proposed rules set out a practical approach to completing the entire process, including compliance repairs.

- A violation that poses imminent danger to life and property must be taken care of immediately;
- Other violations must be corrected within two years; except that
- Up to 5 percent of violations may be corrected in the third year following discovery; and
- For good cause shown and where equivalent safety can be achieved, unless prohibited by law, the Commission may extend the repair for a specific violation.

A typical approach presently is for an inspector or a two-person team to cover a map area or a feeder line. The inspector may perform corrections while at the site. Other problems are recorded and assigned to a service man, or an estimator and line crew, or to a tree trimming crew. Some of the work can require engineering and crew scheduling. Materials may need to be ordered or special equipment rented. Sometimes "packages" of jobs are put out for bid to contractors. Safety can usually be maintained because most items must be replaced while there is still adequate facility strength remaining. This, of course, does not mean that the repairs are deferred for years. If the inspector finds an immediate hazard or emergency situation, it is repaired as the situation demands, perhaps that same day. Ideally, this process gets all of the work done and leaves the system safe and in good repair.

This process makes good sense from a practical and economical viewpoint, and from the safety side. When combined with the 10-year approach ($1/10^{th}$ of the system covered each year), a balance between adequate inspection and corrections, and a reasonable work volume is reached. This all assumes that the process is complete and the repair work done within a reasonable time. The longest "reasonable time" developed by Staff and the industry has evolved into an informal policy of: “Find it this year, fix it the next.” (This is reflected in the PacifiCorp SQM stipulation, for instance.) The concept is that most items are fixed within a year, but in no case would it be longer than the end of the year following the year of discovery. The purpose is to leave each 1/10th of an operator’s system NESC compliant after the inspection and clean-up process is completed, annually. This process is designed to ultimately achieve and maintain overall system compliance with the NESC.

This approach also makes it possible for a very small PUC field staff to evaluate NESC compliance programs. Ideally, each electric supply operator is visited by PUC Staff on an every other year basis. Program designs and records are checked. Then a sample portion of the system that has just been inspected and cleaned up is checked for NESC compliance. This system enables just a couple of PUC field inspectors to be able to cover all 40 Oregon electric operators, and in the process, to inspect facilities of those attaching to the owner’s poles.

The OJUA proposal would repair any imminent dangers, record some violations for repair within 5 years, and roll the remaining NESC violations into “plans of correction” for when major crew work is done at that location in the future, as long as the parties agree. If the utility’s “next major activity” is pole replacement, with modern chemical treatments, this could easily be 20 to 30 years in the future. Maintaining a long list of violations is not the same as having a system that meets NESC requirements. Staff would not practically be able to evaluate multiple-user systems where each operator has lists of “non-hazardous” NESC violations awaiting repair at various convenient times in the future.

The costs associated with the repairs of NESC violations, a concern as expressed by the OJUA has the following two components: A– OJUA believes a very large number of violations will continue to be found during the detailed inspections and that associated repair costs will be overwhelming, and B– The timing for NESC repairs, as proposed by Staff, poses an undue burden on the operators. OJUA asserts that lengthening the timing of repair would make this process more manageable and economical.

To address the concerns expressed by the OJUA, Staff performed a sample audit of 100 poles at eight different Oregon electric utilities. Older urban and suburban areas where the majority of poles had one or more communication attachments were included. The audit criteria called for areas that had not been recently inspected or areas that had been inspected but the corrections had not yet been done. In addition Staff surveyed several electric utilities in Oregon regarding their actual costs of repair for a list of common violations found by Staff during program reviews since 2003. Staff compiled the results to come up with average costs.

A- Of the 800 poles audited, 165 poles were found with violations, comprising a total of 240 violations. By industry the total number of violations (non-repetitive) are; 117 Power, 59 Telephone, and 64 CATV. This indicates that the number of poles with violations, on average, is much lower than estimated by the OJUA, and that the overall density or quantity of violations is also much lower. This also means that costs for repair will be much lower than estimated.

B- OJUA asserts that lengthening the timing for repair will provide the industry a reprieve on their costs for repairs. Staff disagrees. The timing of repairs that Staff has been enforcing for the past 15 years is the most cost efficient way to correct the violation, meaning find this year, budget and correct the next, but no longer than the two years to make the area compliant with the NESC. Please remember this is intended for only 1/10th of the service territory of each operator. The comparison below demonstrates that the OJUA proposal will not only cause a large backlog of documented violations, it will also not result in any long term cost savings or reduced workload for the operator. (This assumes that the NESC violations will actually be fixed).

   a. Staff's Proposal – Calls for all violations found during the year's detailed inspection to be budgeted that year and repaired the next (with minor exceptions). So, if we assign the value of 100% to represent the total number of violations discovered that year, and repair them the year after, the total number of unrepaired violations at the end of the second year, and each subsequent year will be 100%. This process will repeat itself each subsequent year because after the first year there will have been a 100% portion of the violations repaired as well.

   b. OJUA's Proposal – The proposal calls for a 5 year program, plus at the discretion of the operator they may elect to defer the violation to longer periods of time beyond 5 years. If we assume, for sake of simplicity, that all violations will be repaired within 5 years and that the percentage repaired is equal; i.e., 20% per year, we have the following; At year one of the detailed inspection we will have

100% of the violations. At year two we will have 100% of the violations found plus 80% of the violations of the year before as 20% was corrected based on the assumption made – Total is 180%. At year three we will have 100% of the violations found plus 60% of year one, 80 percent of year two – Total is 240%. At year four we will have 100% of the violations found plus 40% of year one, 60% of year two, 80 % of year three – Total of 280%. At year five we will again have 100% of the violations found that year, plus 20% from year one, 40% from year two, 60% from year three, and 80% from year four – Total is 300%. Years 6 through 10 will be the same 300%, and will carry on to the next 10 year cycle.

With year six and thereafter there will be a 300% backlog of documented violations and there will be a 100% volume of repairs being performed each year.

The important point from all these figures is that while the utility might experience reductions in maintenance expense in the first few years using a 5-year program, the cost savings are illusory because they are simply the result of deferring repairs. There are no cost savings any year after year 5 because the same 100% level of violation repairs will have to be made, plus the utility now has an ongoing backlog of documented unrepaired violations. The only way the OJUA proposal could result in savings is if repairs were never made, which is neither realistic nor in compliance with Oregon law. In addition, deferring repairs will extend the safety risk for workers and the public and increase liability for the operator.

The above repair cost models shows Staff's proposal is as cost efficient after the first few years, and is much more effective in bringing the operators system into compliance with the NESC. Please note that the system in the field is dynamic, not static, so the longer an operator carries a violation on their structure, the more complicated and difficult it will be for other operators to attach to that structure, and will increase the chances for an accident. Also note that the benefits of prolonging any repair activity will be offset to some extent by higher labor and material costs in the future.

Staff is concerned with OJUA's "plan of correction" proposal as it pushes the repair to an indefinite time in the future, carrying all the violations forward, which in turn will bring their cost of repair up and will allow the structure to be unsafe for an extended period of time.

ISSUES 3 and 10 STAFF RECOMMENDATION: Staff strongly recommends that the proposed rules in OAR 860-024-0012 be adopted with no changes that would lengthen correction times or weaken these rules. The cost benefit analysis supports these rules. See also the overall Staff recommendation for OAR 860-024-0012 below.

Issue 13: Consider a "generic waiver"

Another issues list item considers the proposed waiver provision. Proposed Rule 0012(4) would allow the Commission to consider alternate requirements under specific circumstances. The applicant operator would have to show "good cause" and provide for equivalent safety. The waiver is limited by existing laws, is for a single specific installation, and allows only a change in the timing of correction.

In discussions, the OJUA seems to be advocating a different type of waiver that would allow deleting specific targeted NESC rules for Oregon. Not only is this type of action not something ever done in the past, Staff questions whether this is what was intended by ORS 757.035(3) which allows substituting for the 1973 NESC or adding to it "any revision or edition of or amendment to the National Electrical Safety Code approved by the American National Standards Institute after July 14, 1977, and in effect on the date of adoption by the commission." This provision allows later American National Standards Institute (ANSI) approved editions to be substituted for the 1973 edition, or for other NESC standards approved by ANSI to be added. While broad safety authority is granted to the Commission in ORS 757.035(1), it specifies that ANSI approved NESC rules were intended. The practice of waiving or deleting selected NESC rules from this national standard does not fit the Legislature's intent.

It obviously is not within the intent of the NESC itself, which is compliance, as explained earlier. Should the industry want to revise the NESC rules, they can propose changes to the NESC's National Committee for consideration. The NESC undergoes a revision process every 5 years that keeps it up-to-date. This is the correct venue for modifying this national utility standard. PGE, for example, has submitted several proposed changes in recent revision cycles, some of which have been accepted.

ISSUE 13 STAFF RECOMMENDATION: Staff recommends that the waiver provision proposed in OAR 860-024-0012(4) not be changed.

Overall Staff Recommendation for OAR 860-024-0012

The Legislature said the ANSI-approved NESC was the requirement in ORS 757.035(2) and (3). The Commission has repeatedly confirmed this by adopting every complete new code edition since 1975. The PUC will no longer be able to efficiently evaluate programs of system maintenance or safety if the OJUA proposal for Rule 0012 is adopted. Before reaching impasse in discussions with the OJUA, staff made considerable compromises on the proposed language for this rule, and firmly believes anything less than what is being proposed in rules will not fulfill the PUC responsibility to require adequate utility safety.

5. OAR 860-024-0014

Duties of Electric Supply and Communication Structure Owners

Issues 5 and 6: Must Structure Owners Perform Assigned Tasks and Should These Rules Be Moved to Division 28?

This is a completely new statement of three basic responsibilities of the structure owner. These rules were prompted by the industry which established OAR 860-028-0120, “Duties of Occupants”. These rules are in the proper division (Division 24) as the requirements are all basic standards which ensure a safe and reliable system. See Exhibit 12, Safety Provisions for Joint-Use of Poles Policy.

The owner must: a) set uniform construction standards, b) establish and maintain communications between joint-users, and c) maintain a safe structure to which others may attach.

This is important because: a) uniform standards make it clear to all parties what each party (including the owner) is required to do during construction and where their equipment is supposed to be located, and b) When communication protocols and contact information are established and maintained, routine daily work can be arranged without delays and frustration, and emergency work under difficult conditions can be accomplished expeditiously. This is essential to safety. With the passage of the Telecommunications Act of 1996, responsible operators were granted access to structures. Of course, there is also a responsibility to maintain facilities in a safe and NESC compliant manner in Oregon. The role of the owner is clarified in c) where responsibility is assigned for maintaining a compliant structure. In addition, the owner is required to respond to a notice of a violation on their structure.

In 2000, Staff recognized that an impediment to joint-use violation correction effectiveness was the lack of communication between the parties. To help correct that problem, Staff began requiring pole owners to host meetings with a Staff member and their joint-users to plan corrections of identified NESC violations after Staff reports were issued. The first of these meetings occurred in November, 2000, at Milton-Freewater, Oregon, related to OPUC Report E00-24. Staff had requested that each joint-use operator bring a copy of their joint use contract with them, to help settle issues that might arise during the meeting. At this meeting it was very apparent that none of the representatives had ever met and they did not have contact information for each other. They dealt with each other through their respective joint use departments. Only one of the parties could produce a copy of the joint use agreement, and it was from 1954.

Now, many regular meetings of joint use partners are occurring. Oregon Trail Electric Cooperative has a quarterly meeting in Baker City, also attended by Idaho Power. A monthly meeting occurs in the Eugene area, alternately hosted by various (6 or 7) utilities. PGE hosts a quarterly meeting, and PacifiCorp has just begun a similar meeting schedule. Consumers Power in Corvallis has established a bi-monthly schedule for meeting with joint-users.

Those meetings, coupled with the networking activities that accompany participation in OJUA activities, demonstrate the importance of communication between the parties recognized by this industry over the last five years. These rules make it clear that these safety basics are required elements of structure management responsibilities.

ISSUES 5 and 6 STAFF RECOMMENDATION: Staff recommends that proposed rules in OAR 860-024-0014 not be changed and that they remain as mandatory safety requirements in Division 24 and not be allowed to be optional by placing them in Division 28.

6. OAR 860-024-0016

Vegetation Clearance Requirements

As discussed under Heading 4, the Commission will need to consider whether the proposed rules will impact Portland General Electric and PacifiCorp because of two requirements. (1) The Service Quality Measures (SQMs) which are stipulated agreements adopted under Commission Orders (PGE – Order Nos. 97-196 and 05-1250 - PP&L – Order Nos. 98-191, 99-616, and 03-528). The measures were adopted, modified, and extended in various cases and were deemed to have a benefit to ratepayers by the multiple parties involved. The stated purpose of the SQMs is "to provide a mechanism to ensure service quality is maintained at current or improved levels…" The Vegetation Management program is specified in the X1 Measure. (2) In addition, there are stipulated agreements with both of these utilities for a ten-year period starting in 1999 that were negotiated in lieu of a Major Safety Violation proceeding regarding inadequate vegetation management programs and hundreds of violations where trees were burning on high voltage lines. (The stipulations and related letters from the Commission Chairman are found in Exhibit 11.) These two electric utilities serve over 70% of Oregon's electric customers. Staff intends to discuss these matters with PGE and PacifiCorp during the upcoming workshops.

Issue 7: What Vegetation Management Standards are Appropriate and How Shall "Interference" be Defined?

This proposed rule is an adaptation of a PUC policy (see Exhibit 6) that originally came almost directly from an Oregon electric utility as part of a collaborative Oregon Utility Safety Committee project in 1982. Very little of substance has been changed except for subpart (8), which requires limited tree clearance work by communication operators.

Some controversy will be related to "interference". The most common occurrence results as the tree grows close to the line or when the line sags into the vegetation on a hot day. Some brushing contacts with the bare high voltage line occur with the sagging or as the breeze moves branches or conductors into each other. In dry weather, probably all that will happen is that leaves and branch tips will be scorched and will die back. If the weather is blustery and wet, a line fuse may blow and some customers will be out of power. These are the mildest and least harmful cases of interference. <u>Staff views interference as an indication of the failure of a vegetation management program to maintain clearances.</u>

The lack of an effective cyclic vegetation management program, one that maintains the minimum clearances, may not be immediately noticeable, but will be greatly magnified over time. Some of those effects are:

- Outages become longer and more frequent.
- Increased fire danger, particularly in rural areas.
- Regular work assignments become longer or more dangerous for utility workers.
- Utility maintenance inspections become more difficult and ineffective.
- Animals and birds will die, bridging between conductors and tree branches; and most importantly,
- People will be injured.

Children will climb trees, landscapers will trim trees close to lines, homeowners will trim or fall trees buzzing on the lines, homeowners will get help from a friend, neighbor, or teenage child to trim that tree, a communication worker wrestling a spinner through a tree will get between the branch and the grounded messenger. All of these are actual occurrences that have been observed or investigated by Staff. Injuries have ranged from a mild shock to devastating burns and in too many cases to death. See Exhibits 7 and 8 for tree-related personal injuries in Oregon.

The Staff policy has always required varying <u>clearances</u> between the high voltage line and the vegetation, increasing as the voltage increases. The purposes of a clearance standard are: a) service reliability, b) reducing power line caused fires, c) the ability to see the system for inspections, d) more efficient and safe workability of the system by power and communication line workers and tree trimming crews, e) to limit the likelihood of vegetation enabled access to power lines and equipment by members of the public, and f) to minimize vegetation caused conductor damage and down conductors.

Power line caused fires are reduced when adequate clearances are maintained. This will not eliminate all fires because whole trees can fail and fall into the lines even when clearances would otherwise be adequate. However, simple contacts between lines and branches (or arc-overs) do cause fires, both small and large. A recent power line caused fire resulted in over three million dollars in damages. A 20-year graph from the Oregon Department of Forestry (ODF) shows an annual average of approximately 44 power line caused fires where ODF crews responded. See Exhibit 9. This graph does not cover all fires in Oregon from this cause, but only those where ODF has responsibility to suppress the fires. This illustrates that maintaining clearances from power lines for the purpose of preventing fires alone is a valid reason for this rule. The other five given purposes above are also, individually, valid reasons to maintain significant clearances between vegetation and high voltage lines.

ISSUE 7 STAFF RECOMMENDATION: Staff recommends that the vegetation clearance standards and practices in Proposed Rule OAR 860-024-0016 including the definition of "interference" not be changed. (See additional Issue 7 recommendations below)

Issue 7 (continued): Defining "Readily Climbable"

Another controversial area is related to "readily climbable" vegetation and how that is defined. For the proposed rules Staff chose a simple, brief, and unambiguous definition because of industry objections to the longer and more detailed one originally proposed. The real issue is to critically evaluate the tree when trimming, and to make the lines inaccessible to unauthorized people (the public). During the informal part of this rulemaking, several definitions were suggested and most were considered by Staff to be acceptable. The definition suggested by OJUA in their Dec. 15, 2005 proposal was acceptable. If another proposal is presented it should be carefully considered.

The graphs shown in Exhibits 7 and 8 provide over 25 years of data for tree related power line contacts. Only some of the Exhibit 7 injuries are related to readily climbable trees, while most Exhibit 8 injuries are from climbing in trees.

ISSUE 7 STAFF RECOMMENDATION: Staff recommends that either the definition for "Readily Climbable" proposed by Staff or that proposed by OJUA in their Dec. 15, 2005 proposal be included in OAR 860-024-0016(1). (See additional issue 7 recommendations)

Issue 7 (continued) (City of Portland): Communication Operator Trimming, and Defining "Interference" and "Readily Climbable" Issues. (see Staff recommendations for these issues above)

Issues related to vegetation management have been raised by City of Portland. In the past, other cities also have desired to impose restrictions on vegetation management to enhance the beauty of their community. In some cases cities have wanted all power and communication lines put underground. There is a natural conflict between larger trees and power line safety especially along crowded public rights of way. There is some flexibility in managing communication lines through trees, but when there are conflicts with high voltage power lines, safety considerations (and service reliability for others) must take priority. Where adequate vegetation clearances from power lines is prevented by local ordinances, the citizens of that area must be willing to accept financial responsibility to achieve an alternate safety solution. The utility company and customers from other communities should not be responsible to bear the costs for non-standard requirements that only benefit one community. A reduction of public safety below set minimum standards should never be acceptable.

Issue 8: Tree Trimming Requirements for Communication Operators

Subpart (8) addresses the limited but very real need for communication operators to perform tree pruning or other protective measures to protect their own facilities and occasionally joint facilities on the pole lines to which they are attached. The assertions that many big old street trees in Portland will have to be destroyed under the original proposed rule are being carefully considered. Although these situations involve only a very small percentage (estimate less than 1%) of Oregon's lines, and alternate solutions such as selective branch removal, guarding, rerouting, or under grounding can solve most of these situations, Staff is willing to reconsider the wording of this rule. The requirement for the communication operators to perform limited vegetation management or facility guarding under appropriate circumstances is recommended for these rules.

ISSUE 8 STAFF RECOMMENDATION: Staff recommends the proposed rule OAR 860-024-0016(8). Some modified wording to accommodate special circumstances may be appropriate, and could be considered if the basic general concept is retained.

Issue 9: Impact of ORS 758.284 on Vegetation Management Rules

The immunity from liability provision of the statute applies only to electric operators. To change this law to include communication operators under its provisions will require legislative action. Electric operators performed vegetation management until very recently without these provisions. While Staff believes these provisions should also be extended to communication operators under the same requirements, the absence of the provisions should not be a basis for deleting the proposal for OAR 860-024-0016 (8) above.

Staff Conclusion for OAR 860-024-0016 Vegetation Management

This rule (OAR 860-024-0016 and presently the policy) is one of the most critical standards needed for the safety of people and property. Tree related injuries (with power lines) have averaged 5.2 per year over the last 20 years. If a homeowner sustains a utility power line injury at his home, chances are very high that it will be tree related. See Exhibit 10.

Issue 14: Application of accident reports

ISSUE 14 STAFF RECOMMENDATION: Staff supports the proposed change to OAR 860-024-0050 which only modifies the property damage threshold amount for reporting. No other changes are recommended.

7. Closing Statements.

Staff has negotiated many compromises in the four meetings of the informal phase of the rulemaking. There have been many good ideas from industry that were incorporated, but in other cases the compromise was to accept what was the lowest level of safety or compliance with other laws, rules, or code requirements that was acceptable or reasonable. Staff recommends that the proposed rules not be further weakened.

Division 24 contains all mandatory rules. There will likely be proposals to change the wording of some of the rule requirements from "Commission Safety Rules" to "NESC." All of the mandatory rules in Division 24 should be included, and narrowing the requirements to only those included in the NESC will significantly reduce the scope of the rules. This scope has been carefully considered in the informal portion of the rulemaking and should not be changed without specific purpose.

Utility safety involving the transportation of energy, inside pipelines (natural gas and some flammable liquids), over wires and cables, and for communication lines covered by the NESC, has been the focus of the OPUC Safety and Reliability Section for 25+ years. Staff function goes far beyond simply advising the Commissioners about the matters under our review. Staff has responsibility for enforcing our rules, and typically the Commission has not had to act unless utility non-cooperation problems arise or a formal decision is required. To the credit of the utility operators, we usually experience reasonable and cooperative responses. We believe the safety rules offered at the start of the rulemaking should be changed only with great care, so that the rules at the end of the process are workable and practical for the industry and for those that must administer them, and will protect workers and the public throughout Oregon as intended and needed.

AR 506

STAFF EXHIBIT 1

Exhibit
STAFF QUALIFICATIONS SUMMARY

J R Gonzalez PE, Manager Utility Safety and Reliability Section OPUC, Associate Degree Campinas State University, BSME Degree Portland State University, MBA Degree City University, 16 years Puget Sound Power & Light (Generating Plant Engineering, Customer Programs, T&D Engineering and Operations, Manager of Metering, Distribution Transformers and Calibration Dept.), CellNet Data Systems and Bechtel Enterprises in Europe (Director of International Program Management), General Dynamics (GD Wireless Sr. Regional Manager for the NW USA, Canada, and Latin America), Personal Consulting Firm (Supported Rogers International Consulting, LLC and EPRI on the Tropical Hardwoods Project), 2 years OPUC. PE Licensed Oregon and Washington.

Jerome A. Murray PE, Senior Utility Analyst; Professional Electrical Engineer licensed in Oregon and Washington; University of California at Davis BSEE 1969; US Navy Civil Engineers Corp 1970-1974 (Construction Manager); Pacific Power and Light 1973-1974 (Transmission Design Engineer); Electric Design Consulting Engineering Firms 1974-1983 (Supervising Engineer); Oregon Public Utility Commission (OPUC) 1983-2004 (Program Manager Utility Safety and Reliability); OPUC 2004-present (Manager of Emergency Preparedness, Response & Security)

John E. Wallace, Senior Utility Analyst; Marysville (Cal.) Union High School 1965, Oregon State University 1970-71, PacifiCorp 1972-1998 (Meter Reader, Apprentice Lineman, Journeyman Lineman, Regional Safety Coordinator, Asst. Operations Manager, Area Operations Manager, Labor Relations Manager), OPUC 1998-present.

Gary Putnam, Senior Utility Analyst, attended University of Oregon, 5 years Contract Line Construction (Ground man, Apprentice, Lineman), 29 years PacifiCorp (Lineman, Foreman, Asst. Superintendent, Superintendent, Operations Manager, Area Operations Manager), 5 years and 10 months Oregon Public Utility Commission Safety and Reliability Section.

Robert Sipler, Senior Utility Analyst (part time); Beaver (Pa.)Area High School 1960, Southern California Edison 1963-68 (Ground man, Crew Assistant, Apprenticeship, Journeyman Cable Splicer/Lineman), Naushon Island (Mass.) Trust 1969-71 (General Maintenance and Construction, Operate Electric Generators and Distribution System and Telephone System), New Bedford (Mass.) Gas and Edison Light 1971-78 (Journeyman Lineman, Transmission Lineman), Multnomah School of the Bible, BS Education 1979-83, OPUC 1984-present, Subcommittee 3 National Electrical Safety Code Standards Committee 1990-present (Secretary 1998-2003).

AR 506

STAFF EXHIBIT 2

How the NESC Code was Prepared
A Historical Perspective (NESC Archives)

Very early in the course of the work all interested parties recognized the necessity for coordinating all agencies throughout the country in order to secure suitable rules for electrical practice. It was seen that only in this way could there be secured a code that would be both adequate and reasonable and to the maximum degree practicable, helpful, and free of embarrassment to all interests.

The Bureau of Standards, Dept of Commerce, under authorization from Congress, begun in 1913 the study of hazards of electrical practice, requesting for the start of the active cooperation of all the interests concerned. This involved a study of all the existing sets of requirements on electrical construction, including a number of State Statutes, Commission Orders, City Ordinances, Company Specifications, and Technical Association Reports, together with the regulations in effect in foreign countries. Examination and study were also made of current electrical practice in this country and of the history of electrical practice so far as this could be determined through the literature on the subject and through correspondence and personal conference.

The studies of the Bureau of Standards resulted in the preliminary drafts of the National Electrical Safety Code, which were intended to include, as far as practicable, for all classes of electrical practice the rules which experience had demonstrated to be necessary and reasonable. The differences between the practices required or employed in different sections or by different interests were studied to learn whether such differences were justified, and if so, to include in the rules a clear basis for such differentiation. In other respects the inconsistencies were removed and the arrangement made as convenient and logical as practicable.

Cooperating Organizations in the Development of the Code

American Electric Railway Association	National Electrical Contractors Association of the USA
American Institute of Electrical Engineers	National Electric Light Association
American Railway Association	National Fire Protection Association
American Railway Engineering Assoc.	National Safety Council
American Telephone & Telegraph Co.	National Workmen's Compensation Service Bureau
Associated Manufac. of Electrical Supplies	Postal Telegraph Co.
Association of Edison Illuminating Co(s)	Underwriters' Laboratories
Association of Railway Telegraph Superintendents	United States Independent Telephone Association
Electrical Manufacturers' Club	Various State Insurance Commissions
Electric Power Club	Various State Labor Commissions
Inter. Association of Municipal Electricians	Various State Public Utility Commissions
I B E W	Western Association of Electrical Inspectors
Nat. Association of Electrical Inspectors	Western Union Telegraph Co.

national electrical safety code archives 914-1972

Vol. NBS Circular 49 1914 1st edition is-
sued Aug 1, 1914 Safety Rules to be ob-
served in the Operation and Maintenance
of Electrical Equipment and Lines

NBS Circular 49 1915 2nd edition is
1 sued May 4, 1915 Proposed National
Electrical Safety **Code,** Part 4

NBS Circular 54 1915 Issued Apr 29,
1915 Proposed National Electrical Safety
Code, Parts 1,2,3

NBS Circular 54 1916 2nd edition is
sued Nov 15, 1916 National Electrical
Safety Code

NBS Circular 72 1918 Issued June
17, 1918 Scope and Application of the
National Electrical Safety Code

2 NBS Handbook No 3 1921 3rd edi
tion Oct 31, 1920 **National Electrical
Safety Code,** Parts 1 to 4

NBS Handbook No 4 1921 Oct 13,
3 1920 Discussion **of the National Elec
trical Safety** Code 3rd edition

NBS Handbook No 3 1927 4th edi
4 tion Dec 21, 1926 **National Electrical
Safety Code,** Parts 1 to 5, Approved Nov
15, 1927 by AESC

5 NBS Handbook No 4 1928 Sep 21,
1928 Discussion of the **NESC** 4th edition

NBS Handbook No 6 1926 Feb 5,
1926 **Electric Supply Stations;** Part 1 and
Grounding Rules of the NESC 4th edition

6

NBS Handbook No 7 1926 Mar 12,
1926 **Electrical Utilization Equipment;**
Part 3 and Grounding Rules of the NESC
4th Edition

NBA Handbook No 8 1926 Jul 15,
1926 **Operation of Electrical Equipment
and Lines;** Part 4 of the NESC 4th edition

NBS Handbook No 9 1926 Jul 15,
1926 **Radio Installations;** Part 5 of the
NESC 4th edition

NBS Handbook No 10 1927 Apr 15,
7 1927 Electrical Supply and Communica
tion Lines; Part 2 of the NESC 4th edition

NBS Handbook H30 1948 Issued Mar
8 1928 (Supersedes H3) [Approved by
the ASA (various dates)] **National Elec
trical Safety Code:** Grounding Rules I, II,
III, IV and V; NESC 5th edition

NBS Handbook H31 1940 Issued
May 8, 1940 (Supersedes H6) [Ap
proved by the ASA May 8, 1941] Elec
trical Supply Stations; Part 1 and the
Grounding Rules of the NESC 5th edition

NBS Handbook H32 1941 Issued Sep
23, 1941 (Supersedes H10) [Approved
9 by the ASA Aug 27, 1941] Electric Sup
ply and Communication **Lines;** Part 2 and
the Grounding Rules of the NESC 5th edi
tion

NBS Handbook H33 1940 Issued Jan
23, 1940 (Supersedes H7) ASA C2.3
1941 (R1941) Approved by ASA May 8,
1941 Electric Utilization Equipment; Part
3 and Grounding Rules of the NESC 5th
edition

NBS Handbook H34 1938 Issued Oct
213, 1938 (Supersedes C49, H8)
ASA C2.4-1939 (R1947) Approved by
ASA Aug 10, 1939 **Operation of Electric
Equipment and Lines;** Part 4 of the NESC
5th edition

10

NBS Handbook H35 1939 Issued Dec
101, 1939 (Supersedes H9) Approved by
ASA Nov 29, 1940 **Radio Installations;**
Part 5 of the NESC 5th edition

NBS Handbook H36 1940 Issued Apr
17, 1940 **Electric Fences;** Part 6 of the
NESC 5th edition

NBS Handbook H39 1944 Issued Jul
15, 1944 **Discussion of the NESC,** Part 2
and Grounding Rules, 5th edition

NBS Handbook H43 1949 Issued Aug
15, 1949 Electric Supply and Com
11 munication Lines; Comprising Part 2 and
the Discussion of Part 2, the Definitions,
and Grounding Rules of the NESC 5th
edition

NBS Handbook H81 Issued Nov 1,
1961 (Supersedes H32 and amends in
part: Part 2, Definitions, and Grounding
Rules; H30, H43) ASA C2.2-1960 Ap
proved by ASA June 8, 1960 **Electric Sup
ply and Communication Lines,** Part 2,
the Definitions, and the Grounding Rules
of the NESC 6th edition

Supplement 1 to NBS Handbook 81 Is
sued Dec 15, 1965 ASA C2.2a-1965 Ap
proved by ASA Jul 29, 1965

12

Supplement 2 to NBS Handbook 81 Is
sued Mar 1968 USAS C2.2b-1967 Ap
proved by ASA Nov 29, 1967

NBS Handbook 110-1 Issued June
1972 ANSI C2.1-1971 Approved by ANSI
Jul 14, 1971 (Supersedes NBS H31 and
pp 31-75 of NBS H30) **Electrical Supply
Stations and Equipment**

"EARLY" LIST OF ACTIONS TAKEN ON THE NATIONAL ELECTRICAL SAFETY CODE BY VARIOUS ADMINISTRATIVE BODIES

FEDERAL BODIES

- United States Employees' Compensation Commission has adopted the code as their electrical standard for inspection of Federal plants.

LEGISLATIVE BODIES

- Montana statute prescribes line rules, requiring compliance with the code for future crossings of supply lines over signal lines or railroad tracks and all future electrical construction not provided for in the act. (Mar. 55, 1957.)

PUBLIC SERVICE, PUBLIC UTILITIES, AND RAILROAD COMMISSIONS

- Arizona Corporation Commission is using the code as a reference standard.
- Colorado Public Utilities Commission has issued bulletin recommending the code. (June 20, 1917.) Adopted part of code relating to grounding of low-potential circuits.
- Connecticut Public Utilities Commission incorporated parts of the code in its joint use requirements. (Mar. 26, 1917.) Requires in some cases that the code be complied with. Has issued circular letter recommending the code in other respects. (Jan. 2, 1918.)
- District of Columbia Engineer Commissioner is using the code as a reference standard, and for high-voltage overhead systems; recommends a trial use of the code. Scope and Application of Safety Code 17.
- Georgia Railroad Commission has issued a bulletin recommending the code. (Oct. 9, 1917.)
- Illinois Public Utilities Commission utilized portions of part 2 of the code in line construction rules. (Oct. 12, 1916.) Is using the code as a reference standard.
- Indiana Public Service Commission requires compliance with rules for grounding of low-voltage circuits. (Dec. 22, 1917.)
- Kansas Public Utilities Commission issued brief of part 2 referring to the complete code. (July 30, 1917.)
- Missouri Public Service Commission requires compliance with the code in particular cases.
- Nevada Public Service Commission has issued bulletin recommending the code. (June 1, 1917.)
- New Hampshire Public Service Commission has issued circular letter requesting trial application of code and is considering advisability of adoption. (Jan. 25, 1918.)
- New York Public Service Commission, first district, is using the code as a reference standard.

- Ohio Public Utilities Commission is using the code as a reference standard and as an authority for decisions in special cases.
- **Oregon Public Service Commission has issued bulletin recommending study of the code preliminary to hearing on its adoption. (Jan. 2, 1918.)**
- Pennsylvania Public Service Commission is using the code informally as a reference standard in cases not covered by formally adopted orders.
- Utah Public Service Commission has tentatively adopted the code. (Feb. 4, 1918.)
- Virginia Corporation Commission has issued a bulletin recommending the code. (Sept. 15, 1917.)
- Washington Public Service Commission is using the code as a reference standard. West Virginia Public Service Commission has issued bulletin recommending the code. (Feb. 28, 1917.)
- Wisconsin Railroad and Industrial Commissions, acting jointly, have issued an order consisting of a condensed set of rules, complying fully with the code and referring to the code for more complete details. (Apr. 30, 1917.)
- Hydro-Electric Power Commission of Ontario is using the code as a reference standard and is preparing rules generally in agreement with the code.
- Nova Scotia Board of Commissioners of Public Utilities has adopted part 2 of the code.

INDUSTRIAL COMMISSIONS.

- California Industrial Accident Commission adopted section 9 and parts 1 and 3 with some minor differences. Uses the code as a standard in inspecting stations.
- Indiana Industrial Board is using the code as a reference standard.
- Ohio Industrial Commission is using the code as a reference standard.
- Pennsylvania Department of Labor and Industry made operative all of the code but part 2 verbatim. (July 1, 1917.)
- Wisconsin Industrial and Railroad Commissions, acting jointly, have issued an order consisting of a condensed set of rules, complying fully with the code and referring to the code for more complete details. (Apr. 30, 1917.)

INSURANCE DEPARTMENTS

- North Carolina Insurance Department issued bulletin recommending the code. (May 4, 1917.)

MUNICIPALITIES

- Chicago Department of Electrical Inspection is using the code as a reference standard.
- New York Department of Water Supply, Gas, and Electricity has indorsed the code for use. 33811°-18 2 18 Circular of the Bureau of Standards

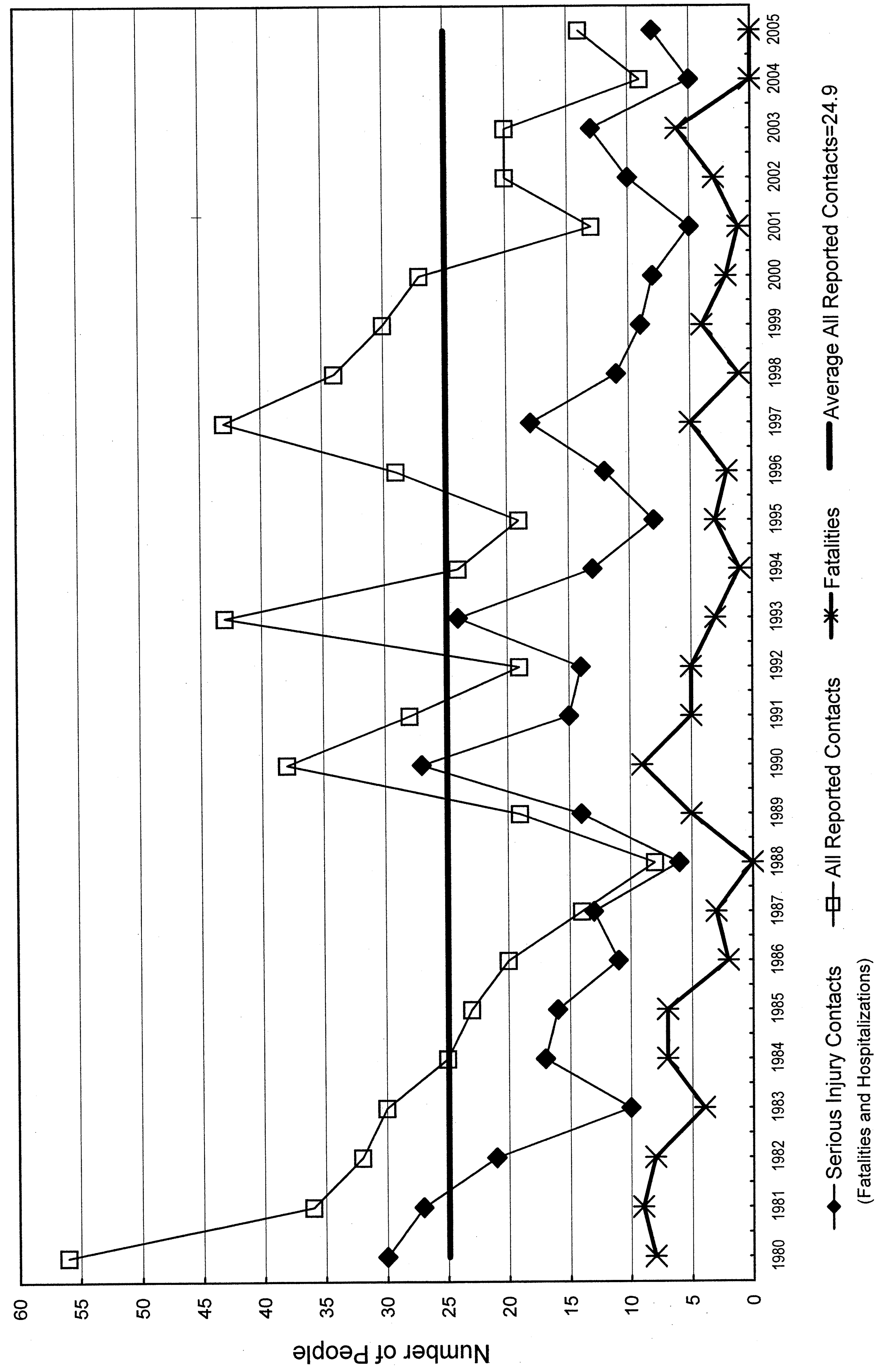
INSPECTION BUREAUS

- The National Workmen's Compensation Service Bureau is using the code as their reference standard for determining casualty insurance rates for electrical stations and lines.
- Indiana Inspection Bureau is using the code as a reference standard and has issued a bulletin recommending the code. (Oct. 23, 1917.)
- Utilities Mutual Insurance Co. (New York State) has issued circular letter recommending application of the code. (Jan. 24, 1918.)

AR 506

STAFF EXHIBIT 3

Incidents Reported by Electric Utilities - 27 Year History



AR 506

STAFF EXHIBIT 4

Oregon Public Utility Commission
Staff Policy
Line Inspection Requirements For Utility Operators

1. PURPOSE

The purpose of this policy is to clarify the line inspection requirements of ANSI-C2, National Electrical Safety Code (NESC), as interpreted by the administrative authority. Specific reference is made to NESC Rule Nos. 012, 013, 121, 214, and 313.

In order to ensure that overhead and underground lines are kept in a safe and relatively trouble-free condition, Utility Operators must make a thorough inspection before a new installation is put into use and at sufficient intervals thereafter. Intervals are determined by considering: age and condition of line, previous inspection and maintenance programs, soil and environmental conditions, weather, and quality of line materials, workmanship and design. Inspections should be preventive in nature and intended to effect repairs previous to failures.

2. SCOPE

This policy applies to the inspection by Utility Operators of all electrical supply and communication lines, both overhead and underground.

3. DEFINITIONS

Lines - Those conductors rights-of-way, supporting structures, and associated equipment used to transmit electric supply energy or communication signals. (Such lines include electric supply, telephone, cable television, and similar utility lines.)

Utility Operator - Any person, company, utility, or municipality, pursuant to ORS 757.035, who is involved in the construction, operation, or maintenance of electrical supply and signal lines.

4. WRITTEN POLICIES AND STANDARD PRACTICES

Each Utility Operator shall have clearly written policies and work practices for its overhead and underground line inspection programs, including: new installation inspections, on-going cyclic inspections of existing lines and substations, and the utility's record keeping system that tracks code violations until corrected.

5. INSPECTION RESPONSIBILITIES (Also see item 7d of OPUC Policy entitled *Safety Provisions for Joint-Use of Poles*.)

Each Utility Operator shall conduct the applicable inspections listed in a., b., c. and d. below. Inspections b. and c. shall be done at such intervals as experience has shown to be necessary in accordance with good practice for the given local conditions.

a. Inspections of New and Repaired Installations

Each new line installation shall be closely checked and corrected for compliance with the NESC before being placed into service.

b. Public Safety Inspections

Public safety inspections are intended to identify hazards and right-of-way encroachments that can be seen during a patrol. These inspections shall include all overhead lines and other accessible equipment. For electric utilities, the maximum cycle length shall not exceed two years. Substations should be inspected monthly.

c. Detailed Facility Inspections

Existing lines shall be carefully inspected on a cyclic basis so that all associated equipment, hardware, right-of-way, and structures are thoroughly examined.

Maximum cycle length for electrical lines and overhead communication lines should not exceed ten years. For older lines (25 years or more) and lines with special concerns, a more frequent inspection may be appropriate.

These precautionary inspections are intended to identify NESC violations, defects, and deterioration of facilities which must be corrected in order to maintain future safe and reliable service.

d. Management Quality Assurance Checks

Each Utility Operator shall conduct management quality assurance checks to ensure that inspections, record keeping, and repairs are being properly conducted. The following is recommended as the minimum level of checking necessary to achieve compliance:

- Inspections of New and Repaired Installations – annually check 10% of all such work performed.
- Public Safety Inspections – annually check 5% of all such work performed.
- Detailed Facility Inspections – annually check 5% of all such work performed.

6. QUALIFIED INSPECTION PERSONNEL

Inspections listed in Item 5 (above) shall be conducted by qualified personnel who have an extensive practical knowledge of the NESC and the company's construction standards. The Utility Operator is responsible to provide its inspection personnel adequate inspection training for the types of facilities inspected.

7. ONGOING UTILITY AWARENESS

In addition to a., b., and c. listed in Item 5 (above), utility employees should constantly be alert, in the normal course of their daily work, to observe conditions that may create a hazard for line workers or the public. Defect reporting and correcting should be a continuous undertaking by the Utility Operator's construction and operating staff.

8. INSPECTION RECORDS

Each Utility Operator shall maintain a record system for tracking of NESC deficiencies found and reported. At minimum, this record system should include:

a. Maps--showing locations of past and planned inspections;
b. Completed Inspection Forms--showing itemization and location of deficiencies found, date, inspector, and inspection type; and
c. Work Orders--showing projects backlogged for future completion.

(Issued November 1987, Revised September, 2000)

AR 506

STAFF EXHIBIT 5

PGE MASTER AGREEMENT THROUGH 2016

Originally adopted in UE 814 per OPUC Order No. 97-196, June 4, 1997
Change 1, Dec. 15, 1998 Public Meeting – X1 interval
Change 2, Dec. 14, 1999 Public Meeting – X2 Substation Equipment
Change 3, Dec, 14, 2005 UF 4218/UM 1206 per OPUC Order No. 05-1250 (use UM 1121 unadopted SQM Stipulated Agreement)

July 13, 2004 / Dec 14, 2005

UM 814 / UM 1121 / UM 1206
STIPULATIONS FOR PGE SERVICE QUALITY MEASURES

TABLE OF CONTENTS

Page	Description
	Summary of Service Quality Performance Measures
1 - 2	Summary -- Table I
3	Summary -- Table II
	Written Stipulations for Service Quality Performance Measures
4 - 7	General Stipulations
7 - 8	C1 Specifications
8 - 9	R1 Specifications
9 - 10	R2 Specifications
10	R3 Specifications
11	R4 Specifications
11 - 12	S1 Specifications
12	X Measures Reporting
13 - 14	X1 Specifications
14 - 21	X2 Specifications
21	X3 Specifications

Summary of Service Quality Performance Measures -- Table I

Code	Description	Measure Value Calculation	OBJECTIVE *(See note 2)*	Revenue Requirement Reduction *(see note 1)*
C1	At Fault Customer Complaints	C1= "At Fault" Complaints/ total number of company customers /1000	____complaints	Please see note #4
R1	Average Interruption Duration	R1 = 3-year weighted average of the SAIDI indices for the three most recent years	_____hours	Please see note #4
R2	Average Interruption Frequency	R2 = 3-year weighted average of the SAIFI indices for the three most recent years	______ occurrences	Please see note #4
R3	Average Momentary Interruption Frequency	R3 = 3-year weighted average of the MAIFI indices for the three most recent years	____events	Please see note #4
R4	Annual Service Restoration Index	R4 = Annual CAIDI, excluding Major Events	_____hours	Please see note #4
S1	Major Safety Violations	S1 = No. of Major Safety Violations	0.0 violations	$100,000 or $500,000 for each major safety violation cited by the Commission. (See page 12 to determine amount.)

Service Quality Performance Measures Summary -- Table I (cont.)

X1	Annual Review Vegetation Management and Service Personnel Count	-Annual report from Co. -Staff evaluations -Submittal to Commrs.	Co. Goals	No specific revenue requirement reduction provisions, possible comm. orders. Inadequate safety in S-1
X2	Annual Review Basic I & M programs	-Annual report from Co. -Staff evaluations -Submittal to Commrs.	Co. Goals	No specific revenue requirement reduction provisions. Possible comm. orders. Inadequate safety in S-1.
X3	Annual Review Special Programs	-Annual report from Co. -Staff evaluations -Submittal to Commrs.	Co. Goals	Advisory only. Proactive preventative programs to enhance safety and reliability, research / trials.

Notes:

1. The company would incur no revenue requirement reductions with proper system operation and maintenance (O&M). Revenue requirement reductions would be incurred, however, in the various areas shown above based upon the level of non-compliance with service/safety standards.

2. Any shortfalls in actual versus allowed expenditures for pertinent accounts during the term of the plan could be subject to customer refunds, if the Commission deems that the company had not engaged in adequate operating practices to maintain safety and reasonable service quality. (See General Stipulations, paragraph F.3.)

3. Any measure exceeding the revenue requirement reduction Line 2 could involve financial revenue requirement reductions and a formal Commission investigation into probable violations of ORS 757.020.

4. For performance at or above ___ and below ___, the PUC may determine a revenue requirement reduction amount of up to $100,000 per year and/or order reasonable corrective actions and/or order a return of unspent O & M funds to customers.
   For performance at or above ___, the PUC may determine a revenue requirement reduction of up to $1,000,000 per year and/or order a return of unspent O & M funds to customers and/or make a determination that inadequate service is being provided in violation of ORS 757.020 (see Note #3 above).

Summary of Service Quality Performance Measure – Table 2

Ranges	Normal Operating Range		Unacceptable Operating Range	
			Revenue Requirement Reduction Range 1	Revenue Requirement Reduction Range 2
Financial Revenue Requirement Reductions	None	None	to $100,000.00 per year for each designated category	to $1,000,000.00 per year for each designated category
			possible return to customers of unspent O & M funds for related programs	possible return to customers of unspent O & M funds for related programs
Additional Commission Order Options	None	None	possible orders to perform corrective actions	possible orders to perform corrective actions
				other orders related to inadequate service as required by ORS 757.020
Performance lines	0.0 Objective Line (Performance Goal)	Revenue Requirement Reduction Line 1		Revenue Requirement Reduction Line 2

Note: Specific values are set for the performance lines for measures CI, RI, R2, R3, R4 and S1. The S1 revenue requirement reduction design is different than Table 2.

SERVICE QUALITY MEASURE STIPULATIONS

GENERAL STIPULATIONS

A. DEFINITIONS:

1. The word "Company" or "Co." shall mean Portland General Electric Company and this company after it's purchase by Oregon Electric Utility Company, LLC (OEUC).

2. The word "Commission" or term "PUC" shall mean Public Utility Commission of Oregon. "Staff" shall mean PUC staff.

3. The term "Service Quality" or "SQ" means those aspects of energy delivery and customer service including, but not limited to, safety, reliability, operations, tariff compliance and customer relations.

4. Performance below the revenue requirement reduction line 1 is the maximum measure value that is considered acceptable.

5. "OAR" shall mean Oregon Administrative Rule.

6. Abbreviations used herein are defined as follows:

ANSI......American National Standards Institute
IEEE......Institute of Electrical and Electronic Engineers
NESC....National Electrical Safety Code
O&M......Operations and Maintenance
T&D.......Transmission and Distribution
I & M......Inspection and maintenance

B. PURPOSE:

The purpose of these performance measures was to provide a mechanism to ensure service quality was maintained at current or improved levels subsequent to PUC approval of the merger of PGC and Enron (UM814). The SQM were modified and the term extended to achieve the same purpose in UM 1121 when ownership was transferred to Oregon Electric Utility Company.

C. PERFORMANCE MEASURES: The nine (9) performance measures for evaluating service quality on an annual basis are as follows:

1. C1....At Fault Customer Complaint Frequency
2. R1....Average Customer Interruption Duration
3. R2....Average Customer Interruption Frequency
4. R3....Average Momentary Interruption Frequency
5. R4 Annual Service Restoration Index
6. S1....Major PUC Safety Violation Frequency
7. X1....Vegetation Management Programs & Service Personnel Count
8. X2 Basic I & M Program
9. X3 Special Programs

These performance measures shall be based on Oregon customers only. See specific measure description for calculations and criteria associated with each measure.

D. COMPLIANCE:

For any specific circumstance, the attached measures should not be used for determining company noncompliance with PUC regulations. These measures and associated agreements do not relieve the company of its legal responsibilities to comply with PUC regulations or orders. Moreover, revenue requirement reduction actions associated with these measures do not preclude the Commission from pursuing compliance actions or civil revenue requirement reductions as allowed by ORS chapters 756 and 757.

E. RECORDS AND REPORTS:

1. The Company and Staff shall meet on or before November 15 of each year to determine reasonable levels for setting the Objective Line, Revenue Requirement Reduction Line 1 and Revenue Requirement Reduction Line 2 for measures C1, R1, R2 R3 and R4 for the following year. If an agreement is reached, a joint report shall go to the Commission recommending these levels. If the Company and Staff do not agree, separate reports with recommended levels will go to the commission for their determination of levels for the coming year. The report(s) shall be submitted to the Commission on or before December 15.

2. The Company shall submit a report annually which documents each measure value and revenue requirement reduction, if any, for the previous calendar year. The annual report shall be completed on forms and computerized spreadsheets prepared by the company and approved by Staff. The report, along with supporting data and calculations on computer disks, shall be submitted to Staff annually on or before May 1 of each year for the preceding calendar year. Each annual report shall explain historical and anticipated trends and events that have affected or will affect the measure in the future.

3. The annual report shall address any company procedural changes that affected the results of the measures or revenue requirement reductions during the preceding year.

4. The Company shall maintain the data, district reports, and field records that document customer interruptions for a minimum of ten years.

5. The data and calculations to develop these measures shall be audited to assure accuracy and compliance with OAR 860-023-0080 through 0160 by the Company's designated reliability engineer.

6. The company shall also provide a separate report for each major event that significantly impacts any of these measures. Upon occurrence of a major event, the company shall submit a written report to PUC Staff within 20 days (see requirements under OAR 860-28-005 and 860-023-0080 through 0160). These reports shall state whether or not the Company intends to request exclusion by the Commission and shall provide the information necessary to determine if the major event meets the PUC data exclusion requirements. The exclusion can be for the entire service area in Oregon or can be limited to one or more specified operational areas (divisions/districts). At minimum, an excluded disaster should satisfy all of the following criteria (similar to IEEE Standard 859-1987):

a: The design limits of the facilities were exceeded;
b. Mechanical damage to lines and facilities was extensive; and,
c. More than 10 percent of the customers were out for over 24 hours.

F. REVENUE REQUIREMENT REDUCTIONS:

1. Unless otherwise specified herein, the company may incur a revenue requirement reduction for substandard performance associated with each measure. The revenue requirement reduction shall be determined using the criteria specified for each performance measure. The company shall pay such revenue requirement reductions through rate reductions or other methods as deemed appropriate by the Commission.

2. Where there are extenuating circumstances that are clearly beyond the company's control, the revenue requirement reductions may be capped or adjusted at the Commission's discretion. Special allowances may be considered by the Commission provided that the company is not found to be in violation of relevant PUC statutes and/or acceptable utility practice.

3. Utility operating and maintenance expenditures in certain key areas have been identified and will be submitted by the company for PUC review annually (see X measures). Any shortfalls in actual versus historical levels of expenditures at a time of unsatisfactory program performance during the term of the plan would be subject to refund with interest at the company's authorized rate of return, if the Commission deemed that the company had not engaged in adequate operating practices to maintain safety and reasonable service quality. This provision is limited to key areas related to the respective service quality measure involved and would apply only if any revenue requirement reduction threshold level (C1, R1, R2, R3,or R4) is exceeded, or if in the Commission's judgment, too many S1 safety violations occur during the term of the plan.

The key expenditure areas related to each performance measure and subject to this provision are as follows:

Measure	Expenditure Area
C1	Customer Service
R1, R2, R3, R4 and S1	Specific program areas related to T&D operations, maintenance and safety, including: • Vegetation Management; • System inspections, maintenance, and repairs; • Pole/structural inspections, replacement and reinforcement; and, • Annual Maintenance Programs in Measure X2

4. For safety violations, the Commission may also pursue actions under ORS 756.990.

5. Disposition of any revenue requirement reduction assessments under agreement shall be at the Commission's discretion and may include, but not be limited to, customer refunds or rate reductions and expenditures on beneficial programs.

G. SPECIAL PROVISIONS:

1. The Commission may direct staff, the utility or a qualified consultant, to conduct special investigations including inspections, testing, audits, and other checks that the Commission deems necessary to assure that the measures and supporting data accurately reflect customer experiences and trends. The cost for such investigations and audits will be borne by the Company. In the event that such investigations reveal noncompliance with the provisions of this document, the company shall make payment for the revenue requirement reduction variances found by the investigations plus interest at the company's authorized rate of return.

2. The Commission, after an opportunity for Company, Staff and public comment, may modify any service quality measure included herein. Modifications could involve, but are not limited to, objective lines, revenue requirement reduction lines, revenue requirement reductions, calculation methods, reporting requirements, or other matters included within this stipulation.

H. TERM:

The original term of this agreement was 10 years, beginning with 1997 (through 2006). This term was extended as modified in UM 1206 through (and including) 2016.

I. SPECIFIC MEASURE STIPULATIONS

1. The specific stipulations for the C1, R1, R2, R3, R4, S1 X1, X2 and X3 are described as follows:

Measure C1 -- Customer "At Fault" Complaint Frequency

1. Description: The C1 measure is the annual total number of "at fault" complaints per 1,000 customers received by the PUC related to company tariffs, policies, standards, and practices involving customer service issues.

2. Definition: An "at fault" complaint is a complaint designated a "COMPLAINT, COMPANY AT FAULT" consistent with current PUC Consumer Service Division practices. "At fault" complaints are identified as follows:

Code	Customer Service Violation Description
"R"	A **rule violation** involves a violation of an Oregon Statute (ORS) or an Oregon Administrative Rule (OAR).
"T"	A **tariff violation** involves a violation of the company's approved tariffs and operating rules as filed with and approved by the PUC.
"C"	A **customer service violation** involves inappropriate and unacceptable customer treatment exemplified by, but not limited to, the following:

- Missed service/repair commitments without prior consumer notification;
- Unreasonable service or repair delays;
- Unreasonable facility installation delays;
- Incorrect, incomplete or misinformation provided to consumers, resulting in customer inconvenience or loss;

- Unreasonable inaccessibility of the company to customers;
- Unreasonable delay in response to consumer inquiry.

Differences and disagreements of "at fault" designations for specific complaints will be submitted for informal supervisory review and if unresolved, may be appealed through existing formal processes for determination by the Commission.

3. **Data Source:** PUC Consumer Services Division records and reports.

4. **Measure Calculation:** The C1 measure is equal to the total number of company "at fault" complaints handled by the PUC during the year, divided by the total average number of company Oregon customers divided by 1,000. The number of customers shall be based on a year-end total of the company's Oregon customers.

5. **Objective:** A performance goal cooperatively set annually by Co. and PUC staff.

6. **Revenue Requirement Reduction Line 1:** A specific number of "at fault" complaints per 1,000 customers set annually.

7. **Revenue Requirement Reduction Line 2:** A specific number of "at fault complaints per 1,000 customers set annually.

8. **Revenue Requirement Reductions:** Revenue requirement reductions shall be assessed for any year that the measure is above the set number of "at fault" complaints per 1,000 customers. The Revenue requirement reductions shall be determined by the Commission based on circumstances and Revenue requirement reduction range options. (See Summary Table 2).

9. **PUC Staff Responsibilities:** PUC Staff shall make available the annual measure value mentioned in the data source (item 3 above) by May 1 of the following year.

<u>Measure R1 -- Average Customer Interruption Duration</u>

1. **Description:** The R1 measure is the weighted average of the last three years' system average interruption duration indices (SAIDI). The SAIDI is the outage time, in hours, that an average customer experiences during the year.

2. **Data Source:** Company's reliability records, data, and certified reports.

3. **Measure Calculation:** The R1 measure is a three-year weighted average of the SAIDI reliability indices experienced by the company's Oregon customers. The weighted average is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor and the second preceding year at a 20 percent factor. The SAIDI is defined and calculated per IEEE and EEI standards (see IEEE draft standard P1366, dated October 18, 1995). This measure is subject to the requirements of OAR 860-023-0080 through 0160.

4. **Objective Line:** A goal cooperatively set annually by the Co. and PUC staff.

5. **Revenue Requirement Reduction Line 1:** A specific number of hours of outage for the averaged customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of hours of outage for the averaged customer set annually.

7. Revenue Requirement Reductions: Revenue Requirement Reductions shall be assessed for any year that the measure is above the Revenue Requirement Reduction lines. The Revenue Requirement Reductions shall be determined by the Commission based on circumstances and Revenue Requirement Reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish an annual R1 measure value mentioned in data source (item 2 above) by May 1 of the following year.

Measure R2 -- Average Customer Interruption Frequency

1. Description: The R2 measure is the weighted average of the last three years' system average interruption frequency indices (SAIFI). The SAIFI index is the number of extended outages that an averaged customer experiences during the year. Extended outages are greater than 5 minutes in length. This measure excludes momentary interruptions caused by automatic substation and line breaker operations.

2. Data Source: Company records, data, and certified reports.

3. Measure Calculation: The R2 measure is a three-year weighted average of the SAIFI reliability indices experienced by the company's Oregon customers. The weighted is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor and the second preceding year at a 20 percent factor. The SAIFI is defined and calculated per IEEE and EEI standards. (See IEEE draft standard P1366, dated October 18, 1995.) This measure is subject to the requirements of OAR 860-023-0080 through 0160.

4. Objective Line: A goal cooperatively set annually by the company and PUC staff.

5. Revenue Requirement Reduction Line 1: A specific number of interruptions for the average Oregon customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of hours for the averaged customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the set number of interruptions. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish annual R2 measure mentioned in data source (item 2 above) by May 1 of the following year.

Measure R3 -- Average Customer Momentary Interruption Frequency

1. Description: The R3 measure is the weighted average of the last three years momentary interruption frequency indices ($MAIFI_E$). The $MAIFI_E$ index is the number of momentary interruptions that an averaged customer experiences during the year.

2. Data Source: Company records, data, and certified reports

3. Measure Calculation: The R3 measure is a three-year weighted average of the $MAIFI_E$ reliability indices experienced by the company's Oregon customers. This average is calculated by adding together the target year at a 50 percent weighting factor, the preceding year at a 30 percent factor, and the second preceding year at a 20 percent factor. The $MAIFI_E$ is defined and calculated per IEEE draft standard P1366, dated October 18, 1995. This index excludes interruptions that are greater than 5 minutes in length, and excludes momentary interruptions that are included in a single relay sequence that results in breaker lockout (extended outage). This measure is subject to the requirements of OAR 860-023-0080 through 0160.

4. Objective Line: A goal cooperatively set annually by the company and PUC staff.

5. Revenue Requirement Reduction Line 1: A specific number of interruptions for the averaged customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of interruptions for the average Oregon customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the revenue requirement reduction line 1. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options. (See Summary Table 2).

8.Company Responsibilities: Company shall furnish annual R3 measure value, as detailed in 2 and 3 above, by May 1 of the following year.

MEASURE R4—ANNUAL SERVICE RESTORATION INDEX

1. Description: The R4 measure is the average time (hours) required to restore service to the average customer per sustained interruption, exclusive of Major Events. This is essentially Customer Average Interruption Duration Index (CAIDI). This measure shall be fully implemented for the first full year, following Commission approval, utilizing historical data as a basis for setting performance lines.

2, Data Source: Company's reliability records, data, and certified reports.

3. Measure Calculation: The R4 measure is calculated each calendar year. R4 equals Annual SAIDI divided by Annual SAIFI. Major Events may be excluded. This measure is subject to the requirements of OAR 860-023-0080 through 0160.

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Line 1 (RRR 1): A specific duration in hours for all Oregon customer sustained interruptions, on average, on an annual basis.

6. Revenue Requirement Reduction Line 2 (RRR 2): A specific duration in hours for all Oregon customer sustained interruptions, on average, on an annual basis.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure amount is a lower percentage number than the set Revenue Requirement Reduction line. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish an annual R4 measure value mentioned in data source (item 2 above) by May 1 of the following year.

Measure S1 -- Major PUC Safety Violation Performance Measure

1. Description: The S1 measure indicates the number of major safety violations cited by the Commission that were in effect during the year. The revenue requirement reductions associated with this measure are to acknowledge the fact that customers have paid for adequate maintenance in their rates and that a major safety violation is a reflection that the company should recompense customers in some manner for the safety situation cited.

2. Definition: A "major safety violation" involves a pattern of serious unsafe conditions or circumstances that put the public, customers, or lineworkers at serious risk of injury, and involves noncompliance with the National Electrical Safety Code (NESC) rules numbers 121, 214, or 313. The three rules address the company's responsibilities to inspect, test, and maintain their powerline facilities so that they are kept in a safe condition. Also, a "major safety violation" could involve any failure by the company to comply with OAR 860-24-0050 in reporting personal injury incidents.

Should Commission Staff determine that the company has committed a major safety violation, Staff will present its recommendation to the Commission. Should the Commission authorize issuance of a citation alleging a major safety violation, the company will be afforded an opportunity to present evidence at hearing under the provisions of ORS 756.515 contesting the alleged violation or violations and evidence of any mitigating factors that the company contends should be considered by the Commission in determining whether to assess the full revenue requirement reduction assessment or a lower amount. A major safety violation must be determined to have occurred by Commission order.

3. Data Source: Commission records.

4. Revenue Requirement Reduction Line: 0.0 major safety violations.

5. Revenue Requirement Reduction Calculation: For each major safety violation cited by the Commission the following will apply:

a. If the company can demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the company shall set aside $0.1 million in revenues it has received from its customers for disposition by the Commission.

b. If the company cannot demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the company shall set aside $0.5 million in revenues it has received from its customers for disposition by the Commission.

c. The maximum assessment for any one major safety violation is $0.5 million.

d. This measure does not have a maximum revenue requirement reduction amount.

Reporting of X1, X2, and X3 Programs

A yearly Maintenance Program Review Meeting will be held by May 1. Applicable information on each program's accomplishments for the year and plans for the next year will be presented to and discussed with OPUC Staff. A written report, both paper copy and on compatible electronic format, will be presented to OPUC Staff at the meeting. This report will summarize all information presented at the yearly meeting. Quarterly updates are provided for the X1 measure.

Measure X1 -- Vegetation Management Program and Service Personnel Count (Oregon)

1. Description: The Vegetation Management Program is a Basic Maintenance Program that is set apart from the other I&M programs due to the crucial effect trees can have on system safety and reliability. Trees and other vegetation are trimmed or removed to provide line clearance and prevent system damage. The service personnel count is a valuable early warning indicator to alert staff of the Company's ability to adequately maintain it's system.

2. Required Interval:

Trimming is accomplished on both a 2 year cycle and a 3 year cycle. Cycle length is determined by the average rate of growth in a given area. Aproximately 50% of the overhead powerline miles are trimmed on a 2 year cycle, 50% on a 3 year cycle. The areas trimmed on a 2 year cycle roughly correspond to metro and suburban areas. Areas trimmed on a 3 year cycle are generally rural. Designation of areas requiring a 2 year cycle or a 3 year cycle are reviewed annually and adjusted as needed to assure compliance with NESC and OPUC's Tree Clearance Policy. Feeders with either 2 years of growth or 3 years of growth, depending on cycle length, that will not be trimmed prior to the onset of winter storm season (approximately November 1) are patrolled in September. Individual trees which may cause problems during storms are then identified with appropriate trimming or removal taking place by October 15.

3. PGE Quality Control:
Not less than 10% of recently completed tree trimming is inspected on a continuous basis to ensure compliance to the Program Plan and achievement of adequate clearance.

4. Program Expenditures:
Annual budget with actual versus planned expenditures. Information will include total budget and the following elements: Maintenance Cycle Trimming, Customer Assistance Trimming, Line Construction Trimming, and PGE supervision and Administration.

5. Personnel Information (Count in each category):
-<u>PGE Forester</u> FTEs
-<u>Average number of Contract Tree Crews</u>
-<u>Service Representatives</u> (Credit Phones, Credit Paperwork, Billing Paperwork, General Support (Administration), Community Offices, Business Products & Services Team, and Consumer Assistance Phones)
-<u>Engineering Services</u> (Electrical Engineer I, II, III, and IV, Civil Engineer IV, Mechanical Engineer IV, Service and Design Consultants II, III, and IV)
-<u>Field Services</u> (Line Crew: Assistant Derrick Truck Operator, Derrick Truck Operator, Backhoe Operator, Line Truck Driver B, Construction Working Foreman, Line Working Foreman, Pole Yard Foreman, Groundmen, Apprentice Lineman, Journeyman Lineman, Leadman Lineman, Equipment Operator B and C, Heavy Equipment Operator, Leadman Repairman, Underground Working Foreman, Underground Construction Foreman, Cable Splicer, Cable Splicer Assistant, Underground Helpers, Special Tester, Senior Special Tester, and Utility Worker)
-<u>Substation</u> (Battery Man, Wireman Working Foreman, Substation Inspector, Crane Operator, Meter and Relay Technician, Senior Meter and Relay Technician, Apprentice Wireman, Wireman, Wireman Helper, Construction Wireman, Wireman Foreman, and Wireman Leadman)
-<u>Meter Area</u> (Meter Shop Working Foreman, Meterman Working Foreman, Journeyman Meterman, and Meterman Apprentice)

6. Data Source: Company records, data and reports. Staff data review and field review.

7. Measure Calculation: There is no individual measure calculation. An annual report with staff comments and recommendations will be submitted to the commission each spring (May 1) for their review and any action deemed appropriate. Program problems will normally result in NESC violations being cited by PUC staff with extensive problems resulting in a major PUC Safety Violation (Measure S1).

<u>Measure X2 -- Basic Inspection and Maintenance Programs</u>

<u>I. Inspection and Repairs</u>

A. Pole and Overhead Facilities Inspection and Repair include the inspection and treatment of all PGE-owned distribution and transmission poles and overhead distribution facilities. All PGE-owned poles are tested for strength and treated with wood preservative. Distribution equipment attached to any pole is inspected, repaired, or replaced to ensure the electrical system remains in good working order and meets the National Electric Safety Code (NESC). The first cycle was completed in 1996 (transmission poles by July 1, 1997). The current cycle began January 1997.

Required Interval:

10-year cycle, 10% annually with no individual year falling below 8.5%. Repairs or replacement completed within 120 days of discovery.

PGE Quality Control:

Monthly inspection by appropriate random sample to ensure accuracy of inspection. Minimum 5% of repair or replacement work is inspected as needed to ensure NESC compliance.

Program Expenditures:

Annual budget figures to include:

- Pole and Overhead Facilities Inspection and Pole Treatment
- Repair and Replacement of Facilities

B. Safety Survey is a drive-by survey of the Distribution system. The survey is designed to spot incidental damage to the system (such as damage from stormy weather) that neither caused an outage nor was reported.

Required Interval:

2-year cycle with 50% of the system driven yearly.

PGE Quality Control:

Random sample by supervisory personnel or their designees to ensure uniform results and adherence to the plan and accuracy of survey.

Program Expenditures:

Planned and actual annual budget.

C. Underground Inspection Program includes a thorough visual inspection of underground vaults, pad-mount transformers, switches, and an infrared inspection of all accessible terminals and splices. The first cycle started in 1996 and the current one in January 2004.

Required Interval:

4-year cycle, 25% of the system annually with no individual year falling below 20% of the system.

PGE Quality Control:

Monthly inspection by appropriate random sample to ensure accuracy of inspection.

Program Expenditures:

Annual budget figures to include:

- Facilities Inspection
- Repair and Replacement of Facilities

D. Substation Safety is an inspection of each substation on the Transmission and Distribution system. The survey is designed to spot vulnerability of intrusion of the enclosure fences, NESC compliance, incidental damage to substation equipment, and the integrity of the operational system.

Required Interval:

1-month cycle for all substations.

PGE Quality Control:

Random sample by supervisory personnel to ensure accuracy of survey. A review of a monthly computer report that describes results by assigned inspector in an assigned area.

E. Marina Inspection Program is a PGE facilities inspection at every marina in our service area. Marinas are inspected during the winter at high-water conditions and in the summer at low-water.

Required Interval:

Twice yearly; once during high-water and once during low-water.

PGE Quality Control:

A random sample is reinspected by the supervisor or designee to ensure accuracy of inspection and NESC code compliance.

F. Major Equipment Maintenance

1. Line Equipment:

a. Pole Top Reclosers and Sectionalizer Program include the inspection and maintenance of oil filled reclosers, vacuum reclosers and sectionalizers. Periodically or by operations count, this equipment is removed from service, maintained, and reinstalled.

Required Interval:

The equipment is inspected annually. Oil reclosers are maintained on a 5 year cycle or 50 operations, whichever occurs first. Vacuum reclosers are maintained on a 10 year cycle or 100 operations, whichever occurs first. Sectionalizers are maintained on a 10 year or 50 operations, whichever occurs first.

PGE Quality Control:

The program is controlled by a program manager who ensures implementation and coordination. Individual engineers are assigned geographic areas and monitor the program in the field.

b. Pole Top Voltage Regulators Program includes the inspection and maintenance of these devices.

Required Interval:

Voltage regulators are inspected annually and are maintained on a 10 year cycle or 200,000 operations, whichever occurs first.

PGE Quality Control:

The program is controlled by a program manager who ensures implementation and coordination. Individual engineers are assigned geographic areas and monitor the program in the field.

c. Switch Maintenance Program includes inspecting operating, adjusting, repairing, or replacing all PGE owned pole mounted distribution switches.

Required Interval:

Five year cycle with the first cycle having been started in 1995.

PGE Quality Control:

The program is controlled by a program manager who ensures implementation and coordination. Individual engineers are assigned geographic areas and monitor the program in the field.

2.Substation Equipment

Substation Program Expenditures:

Program expenditures are not broken down by equipment. Total program expenditures are reported annually for all Substation Maintenance Activities. Additional detail will be provided upon staff request.

Substation Quality Control (for 2b through 2h):

Random sampling of field personnel activities and post completion management reviews of 10% of testing results by technical personnel to assure adherance to PGE approved manitenance proceedures.

a. Batteries:

Purpose:

Batteries supply a reliable, independent source of power. This ensures the proper operation of breakers, protective relays and motor operators during adverse weather conditions and emergencies, to assure safety and system reliability.

Maintenance:

>Operating condition assessment monthly
>Individual cell assessment semi-annually
>Testing at 5 year planned intervals to verify battery capacity
>Battery replacement occurs when tests are failed

Quality Control:

Post completion reviews of testing results by technical personnel to assure adherence to PGE battery maintenance proceedures.

b. Capacitor Banks:

Purpose:

Capacitors operate to provide reactive power support and reduce system losses.

Maintenance:

- Operating condition assessment monthly
- Non-intrusive diagnostic tests semi-annually
- Capacitor replacement as indicated by tests or upon unit failure

c. Breakers:

Purpose:

Breakers must operate automatically and upon demand to protect system components and equipment in emergencies or during fault conditions which assures safety, system reliability, and efficient operation of the system.

Maintenance:

- Operating condition assessment monthly

- Non-intrusive diagnostics annually
- Minor service at 2-5 year planned intervals based on equipment type and it's impact on safety and reliability.
- Major service or equipment replacement as determined by diagnostic data and assessment.

d. Disconnect Switches & Connectors

Purpose:

Disconnect switches and connectors operate to provide low resistance electrical connections that can be opened when necessary to provide isolation points for emergency and routine work.

Maintenance:

- Operating condition assessment monthly
- Non-intrusive diagnostics annually
- Equipment repair or replacement as determined by diagnostic data and assessment.

e. Load Tap Changers(LTCs)

Purpose:

Maintain system voltage within a desired operating band to assure consistent reliable service and customer equipment performance.

Maintenance:

> Operating condition assessment monthly

> Non-intrusive diagnostics annually

> Major service or equipment replacement as determined by diagnostic data and field assessment.

f. Regulators:

Purpose:

Maintain system voltage within a desired operating band to assure consistent reliable service and customer equipment performance.

Maintenance:

- Operating condition assessment monthly
- Non-intrusive diagnostics annually
- Major service or equipment replacement as determined by diagnostic data and field inspection.

g. Transformers:

Purpose:

Transformers raise or lower voltage to provide the means to efficiently move electrical energy from source to point of use. They are the most capital intensive of substation equipment are maintained to assure that their life is maximized and to enhance reliability.

Maintenance:

- Operating condition assessment monthly
- Non-intrusive diagnostics annually
- Non-intrusive electrical diagnostics testing when diagnostics indicate
- Major service or replacement as determined by diagnostic data.

h. Protective Relaying:

Purpose:

Relays are maintained to assure adequate protective actions occur to trip faulted equipment and lines to protect system components and assure safety.

Maintenance:

> Electro-mechanical protective relays are tested and calibrated at a 6 year planned interval (except transmission line).

- Electro-mechanical transmission line protective relays are tested and calibrated at a 3 year interval.
- Electronic (IED) relays are inspected (calibration not required) on the same interval as the Electro-mechanical relays.

3. Metering Program

a. Meter System Accuracy Program:

Meter test program tests for accuracy of installed electric meters, a general inspection and verification of the associated equipment including all instrument transformers and associated wiring. The program places meters into one of two groups; self contained, non-demand meters or demand/ instrument transformer rated meters.

A sample test program is used for self contained, non-demand meters. The meters are grouped by manufacturer, model and age. A random sample is selected from each group or lot and tested. Any group that falls outside set standards is replaced.

A periodic program includes the testing, inspection and verification for all demand or instrumental transformer rated meters. The meters are grouped by manufacturer, equipment type, and last test date. Meter systems falling outside set standards are corrected, recalibrated or replaced.

The Company shall provide an annual certification report and presentation to PUC Staff by May 1 detailing the previous years metering program. The report shall include information for each meter group concerning metering system accuracy and inspections for proper installation, safety, and security. Additionally, the certification report shall include, for each meter group, the number of Oregon meter tests, inspections, and retirements planned for the current year. Further, the report shall contain summary information on metering program accomplishments, issues, trends, failed meter types and installations, meter repairs, retirements, program modifications, and new applied technologies.

Required Interval:

Sample test program is run yearly. Periodic test program test interval varies by meter type. All primary service customers with TOD or TOU metering are tested and verified yearly. All solid state electric meters and all other primary service customers that don't fall into the one year group are tested and verified on a five year schedule. Induction or induction / solid state hybrid style meters including all instrument transformer rated demand meters and all self contained demand meters are tested and verified on a 12 year schedule. Finally, all induction style, instrument rated, non-demand meters are tested and verified on a 16-year schedule.

PGE Quality Control:

Random sample by supervisory personnel or their designer to ensure uniform results and adherence to the plan and accuracy of data.

II. STANDARDS AND STANDARD PRACTICES

Company Standards including standard practices are necessary to ensure compliance with NESC, NEC, PGE tariffs, PUC laws and good engineering practice. Annual reviews and quality control of the below standards are necessary to ensure that they remain current and are being uniformly implemented in the field:

Electric Service Requirements

Joint-Use Standards

Construction Standards

Design Standards

Operation and Maintenance Standard Practices

Quality Control Program

Required Interval:

Annual and other needed reviews of the above standards by PGE Standards department to resolve standards issues associated with customer complaints, joint-use conflicts, PUC enforcement actions, code and regulation changes, etc.

PGE Quality Control:

Annual review by Company Standards engineer to ensure that the above standards are updated. Random sample by standards personnel to ensure uniform results and adherence with the standards in the field.

Measure X3 -- Special Programs

Special Programs address specific issues which may effect T&D operation, maintenance or safety. They normally operate for a specific period of time, accomplish their intended purpose, and are terminated upon completion. Information discovered in the program may result in the establishment of specific, routine, ongoing programs.

These special programs will be reviewed annually and reported on to OPUC staff. The list of special programs is expected to change annually.

PACIFICORP MASTER AGREEMENT THROUGH 2014
AFOR SQMs UE 94, Feb. 12, 1998,OPUC Order 98-191/ScottishPwr Merger Modifications UM 918, OPUC Order 99-616-June 16, 1999/UE 1147 Term Extension (through 2014) OPUC Order 03-528.
Change 1: Dec. 14, 1999 Public Meeting - 3 items modified.
Change 2: July 1, 2003 Public Meeting – Reporting on Fiscal Year (4/1 through 3/31), also reasonable 10% improvements in SAIDI and SAIFI goals indicated.
Change 3: Dec. 7, 2004 Public Meeting – R4 Measure changed to CAIDI.

UE 94/UM 918/UE 147
SERVICE QUALITY MEASURES

TABLE OF CONTENTS

Page	**Description**
	Summary of Service Quality Performance Measures
2 - 3	Summary -- Table I
4	Summary -- Table II
	Written Agreements for Service Quality Performance Measures
5 - 8	General Agreements
8 - 10	C1 Specifications
10 - 11	R1 Specifications
11 - 12	R2 Specifications
12 - 13	R3 Specifications
13 - 14	R4 Specifications
14 - 15	S1 Specifications
15 - 16	X1 Specifications
16 - 22	X2 Specifications
22 - 23	X3 Specifications
23	Reporting of X Programs

Summary of Service Quality Performance Measures -- Table I

Code	Description	Measure Value Calculation	OBJECTIVE	Revenue Requirement Reduction *(see notes 1 and 2)*
C1	At Fault Customer Complaints	C1= "At Fault" Complaints/ total number of Company customers /1000	____complaints	Please see note #3
R1	Average Interruption Duration	R1 = 3-year weighted average of the SAIDI indices for the three most recent years	_____hours	Please see note #3
R2	Average Interruption Frequency	R2 = 3-year weighted average of the SAIFI indices for the three most recent years	______ occurrences	Please see note #3
R3	Average Momentary Interruption Frequency	R3 = 3-year weighted average of the MAIFI indices for the three most recent years	____events	Please see note #3
R4	Annual Service Restoration Index	R4 = Annual CAIDI, with Major Events excludable	____ %	Please see note #3
S1	Major Safety Violations	S1 = No. of Major Safety Violations	0.0 violations	$100,000 to $500,000 for each major safety violation cited by the Commission. (See page 12 to determine revenue requirement reduction amount.)
X1	Annual Review Vegetation Management	-Annual report from Company -Staff evaluations -Submittal to Commissioners.	Company Goals	No specific revenue requirement reduction provisions, possible comm. orders. Inadequate safety in S-1.

(cont'd)

Service Quality Performance Measures Summary -- Table I (cont.)

X2	Annual Review Basic I & M programs	-Annual report from Company -Staff evaluations -Submittal to Commissioners	Company Goals	No specific revenue requirement reduction provisions. Possible comm. orders. Inadequate safety in S-1.
X3	Annual Review Special Programs	-Annual report from Company -Staff evaluations -Submittal to Commissioners	Company Goals	Advisory only. Proactive preventative programs to enhance safety and reliability, research/trials.

Notes:

1. The Company would incur no revenue requirement reductions with proper system operation and maintenance (O&M). Revenue requirement reductions would be incurred, however, in the various areas shown above based upon the level of non-compliance with service/safety standards.

2. Any shortfalls in actual versus allowed expenditures for pertinent accounts during the term of the plan could be subject to customer refunds, if the Commission deems that the Company had not engaged in adequate operating practices to maintain safety and reasonable service quality. (See General Stipulations, paragraph F.3.)

3. For performance at or above ___ and below ___, the PUC may determine a revenue requirement reduction amount of up to $100,000 per year and/or order reasonable corrective actions and/or order a return of unspent O & M funds to customers.
   For performance at or above ___, the PUC may determine a revenue requirement reduction of up to $1,000,000 per year and/or order a return of unspent O & M funds to customers and/or make a determination that inadequate service is being provided in violation of ORS 757.020.

Summary of Service Quality Performance Measure – Table 2

Ranges	Normal Operating Range		Unacceptable Operating Range	
			Revenue Requirement Reduction Range 1	**Revenue Requirement Reduction Range 2**
Financial Revenue Requirement Reductions	None	None	to $100,000.00 per year for each designated category	to $1,000,000.00 per year for each designated category
			possible return to customers of unspent O & M funds for related programs	possible return to customers of unspent O & M funds for related programs
Additional Commission Order Options	None	None	possible orders to perform corrective actions	possible orders to perform corrective actions
				other orders related to inadequate service as required by ORS 757.020
Performance lines	0.0	Objective Line (Performance Goal)	Revenue Requirement Reduction Threshold Line	Revenue Requirement Reduction Line 2

Note: Specific values are set for the performance lines for measures CI, RI, R2, R3, R4 and S1. The S1 revenue requirement reduction design is different than Table 2. The Commission reserves the right to pursue other formal actions for service not deemed adequate pursuant to the standards set forth in ORS 757.020.

SERVICE QUALITY MEASURES

A. DEFINITIONS:

1. "Company" shall mean PacifiCorp, operating in Oregon as Pacific Power and Light Company and this company after the merger with ScottishPower.

2. "Commission" or "PUC" shall mean Public Utility Commission of Oregon. "Staff" shall mean PUC Staff.

3. "Service Quality" or "SQ" means those aspects of energy delivery and customer service including, but not limited to, safety, reliability, operations, tariff compliance and customer relations.

4. Performance below the revenue requirement reduction threshold line is the maximum measure value that is considered acceptable.

5. "OAR" shall mean Oregon Administrative Rule.

6. Abbreviations used herein are defined as follows:

   ANSI......American National Standards Institute
   IEEE.......Institute of Electrical and Electronic Engineers
   NESC.....National Electrical Safety Code
   O&M......Operations and Maintenance
   T&D.......Transmission and Distribution
   I & M......Inspection and maintenance

7. "Year" or "Annual" for the purposes of SQM reporting will be a one year period starting April 1 of the designated year and ending on the following March 31.

B. PURPOSE:

The purpose of these performance measures is to provide a mechanism to ensure service quality is maintained at current or improved levels subsequent to implementation of an alternate form of regulation (AFOR) for the Company. In addition, modifications were made to incorporate provisions of the ScottishPower merger in UM 918.

C. PERFORMANCE MEASURES:

The nine (9) performance measures for evaluating service quality on an annual basis are as follows:

1. C1 At Fault Customer Complaint Frequency
2. R1 Average Customer Interruption Duration
3. R2 Average Customer Interruption Frequency
4. R3 Average Momentary Interruption Frequency
5 R4 Annual Service Restoration Index

6. S1 Major PUC Safety Violation Frequency
7. X1 Vegetation Management Programs and Service Personnel Count
8. X2 Basic I & M Program
9. X3 Special Programs

These performance measures shall be based on Oregon customers only. (See specific measure description for calculations and criteria associated with each measure.)

D. COMPLIANCE:

For any specific circumstance, the attached measures should not be used for determining Company noncompliance with PUC regulations. These measures and associated agreements do not relieve the Company of its legal responsibilities to comply with PUC regulations or orders. Moreover, revenue requirement reduction actions associated with these measures do not preclude the Commission from pursuing compliance actions or civil revenue requirement reductions as allowed by ORS chapters 756 and 757.

E. RECORDS AND REPORTS:

1. The Company and Staff shall meet on or before November 15 of each year to determine reasonable levels for setting the Objective Line, Revenue Requirement Reduction Threshold Line and Revenue Requirement Reduction Line 2 for measures C1, R1, R2, R3 and R4 for the following year. If an agreement is reached, a joint report shall go to the Commission recommending these levels. If the Company and Staff do not agree, separate reports with recommended levels will go to the commission for their determination of levels for the coming year. The report(s) shall be submitted to the Commission on or before December 15.

2. The Company shall submit a report annually which documents each measure value and revenue requirement reduction, if any, for the previous year. The annual report shall be completed on forms and computerized spreadsheets prepared by the Company and approved by Staff. The report, along with supporting data and calculations on computer disks, shall be submitted to Staff annually on or before May 15 of each year for the preceding year. Each annual report shall explain historical and anticipated trends and events that have affected or will affect the measure in the future.

3. The annual report shall address any Company procedural changes that affected the results of the measures or revenue requirement reductions during the preceding year.

4. The Company shall maintain the data, district reports, and field records that document customer interruptions for a minimum of ten years.

5. The data and calculations to develop these measures shall be audited to assure accuracy by the Company's designated reliability engineer.

6. The Company shall also provide a separate written report for a major event that significantly impacts any of these measures. The written report shall comply with

OAR 860-023-0160 requirements. A major event, as defined in OAR 860-023-0080 means a catastrophe event that:

a. Exceeds the design limits of the electrical power system;
b. Causes extensive damage to the electric power system; and
c. Results in a simultaneous sustained interruption to more than 10 percent of the customers in an operating area.

The report shall be submitted to PUC Staff within 20 working days of the occurrence of the major event. These reports shall state whether or not the Company intends to request exclusion by the Commission from the reliability measures (R1, R2 R3 and R4) and shall provide the information necessary to determine if the major event meets the exclusion requirements as defined above. The exclusion can be for the entire service area in Oregon or can be limited to one or more specified operational areas (divisions).

F. REVENUE REQUIREMENT REDUCTIONS:

1. Unless otherwise specified herein, the Company may incur a revenue requirement reduction for substandard performance associated with each measure. The revenue requirement reduction shall be determined using the criteria specified for each performance measure. The Company shall pay such revenue requirement reductions through rate-reductions or other methods as deemed appropriate by the Commission.

2. The revenue requirement reductions may be waived, capped or otherwise adjusted by the Commission under extenuating circumstances clearly beyond the Company's control. Special allowances may be considered by the Commission provided that the Company is not found to be in violation of relevant PUC statutes and/or acceptable utility practice.

3. Utility operating and maintenance expenditures in certain key areas have been identified and will be submitted by the Company for PUC review annually (see key expenditure areas below). Any shortfalls in actual versus historical levels of expenditures at a time of satisfactory program performance during the term of the plan would be subject to refund with interest at the Company's authorized rate of return, if the Commission deemed that the Company had not engaged in adequate operating practices to maintain safety and reasonable service quality. This provision is limited to key areas related to the respective service quality measure involved and would apply only if any revenue requirement reduction threshold level (C1, R1, R2, R3 or R4) is exceeded, or if in the Commission's judgment, too many S1 safety violations occur during the term of the plan.

   The key expenditure areas related to each performance measure and subject to this provision are as follows:

Measure	Expenditure Area
C1	Customer Service

R1, R2, R3, R4 and S1	Specific program areas related to T&D operations, maintenance and safety, including: • Vegetation Management (XI); • System inspections, maintenance, and repairs; and • Pole/structural inspections, replacement and reinforcement.

4. For safety violations, the Commission may also pursue actions under ORS 756.990.

5. Disposition of any revenue requirement reduction assessments under agreement shall be at the Commission's discretion and may include, but not be limited to, customer refunds or rate reductions and expenditures on beneficial programs.

G. SPECIAL PROVISIONS:

1. The Commission may direct Staff, the utility or a qualified consultant, to conduct special investigations including inspections, testing, audits, and other checks that the Commission deems necessary to assure that the measures and supporting data accurately reflect customer experiences and trends. The cost for such investigations and audits will be borne by the Company. In the event that such investigations reveal noncompliance with the provisions of this document, the Company shall make payment for the revenue requirement reduction variances found by the investigations plus interest at the Company's authorized rate of return.

2. The Commission, after an opportunity for Company, Staff and public comment, may modify any service quality measure included herein. Modifications could involve, but are not limited to, objective lines, revenue requirement reduction lines, revenue requirement reductions, calculation methods, reporting requirements, or other matters included within this stipulation.

H. TERM:

The original term of this agreement was 10 years, beginning in January 1, 1998, and was extended through Dec. 31, 2009, and again extended through (and including).2014. The Commission allowed PP&L to change to a SQM reporting year (4/1 through 3/31) in 2003, changing the end of the term to March 31, ~~2010~~.2015.

I. SPECIFIC MEASURE AGREEMENTS:

The specific agreements for the C1, R1, R2, R3, R4, S1, X1, X2, and X3 are described as follows:

MEASURE C1 -- CUSTOMER "AT FAULT" COMPLAINT FREQUENCY

1. Description: The C1 measure is the annual total number of "at fault" complaints per 1,000 customers received by the PUC related to Company tariffs, policies, standards, and practices involving customer

service issues.

2. Definition: An "at fault" complaint is a complaint designated a "COMPLAINT, COMPANY AT FAULT" consistent with current PUC Consumer Service Division practices. "At fault" complaints are identified as follows:

Code	Customer Service Violation Description
"R"	A rule violation involves a violation of an Oregon Statute (ORS) or an Oregon Administrative Rule (OAR).
"T"	A tariff violation involves a violation of the Company's approved tariffs and operating rules as filed with and approved by the PUC.
"C"	A customer service violation involves inappropriate and unacceptable customer treatment exemplified by, but not limited to, the following: • Missed service/repair commitments without prior consumer notification; • Unreasonable service or repair delays; • Unreasonable facility installation delays; • Incorrect or incomplete information provided to consumers, resulting in customer inconvenience or loss; • Unreasonable inaccessibility of the Company to customers; • Unreasonable delay in response to consumer inquiry.

Differences and disagreements of "at fault" designations for specific complaints will be submitted for informal supervisory review and if unresolved, may be appealed through existing formal processes for determination by the Commission.

3. Data Source: PUC Consumer Services Division records and reports.

4. Measure Calculation: The C1 measure is equal to the total number of Company "at fault" complaints handled by the PUC during the year, divided by the total average number of Company Oregon customers divided by 1,000. The number of customers shall be based on a year-end total of the Company's Oregon customers.

5. Objective: A performance goal cooperatively set by the Company and PUC Staff.

6. Revenue Requirement Reduction Threshold: A specific number of "at fault" complaints per 1,000 customers set annually.

7. Revenue Requirement Reduction Line 2: A specific number of "at fault" complaints per 1,000 customers set annually.

8. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the set number of "at fault" complaints per 1,000 customers. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options. (See Summary Table 2).

9. PUC Staff Responsibilities: PUC Staff shall make available the annual measure value mentioned in the data source (item 3 above) by May 15 of the following year.

MEASURE R1 -- AVERAGE CUSTOMER INTERRUPTION DURATION

1. Description: The R1 measure is the weighted average of the last three years' system average interruption duration indices (SAIDI). The SAIDI is the outage time, in hours, that an average customer experiences during the year.

2. Data Source: Company's reliability records, data, and certified reports.

3. Measure Calculation: The R1 measure is a three-year weighted average of the SAIDI reliability indices experienced by the Company's Oregon customers. The weighted average is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor and the second preceding year at a 20 percent factor. The SAIDI is defined and calculated per IEEE and EEI standards (*see* IEEE draft standard P1366, dated October 18, 1995).

4. Objective Line: A goal cooperatively set by the Company and PUC Staff. *See note, pages 11-12 .

5. Revenue Requirement Reduction Threshold: A specific number of hours of outage for the average customer set annually. *See note, pages 11-12.

6. Revenue Requirement Reduction Line 2: A specific number of hours of outage for the averaged customer set annually. *See note, pages 11-12 .

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the Revenue Requirement Reduction lines. The revenue requirement reductions

shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish an annual R1 measure value mentioned in data source (item 2 above) by May 15 of the following year.

MEASURE R2 -- AVERAGE CUSTOMER INTERRUPTION FREQUENCY

1. Description: The R2 measure is the weighted average of the last three years' system average interruption frequency indices (SAIFI). The SAIFI index is the number of extended outages that an average customer experiences during the year. Extended outages are greater than 5 minutes in length. This measure excludes momentary interruptions caused by automatic substation and line breaker operations.

2. Data Source: Company records, data, and certified reports.

3. Measure Calculation: The R2 measure is a three-year weighted average of the SAIFI reliability indices experienced by the Company's Oregon customers. The weighted average is calculated by adding together the target calendar year at a 50 percent weighting factor, the preceding year at a 30 percent factor and the second preceding year at a 20 percent factor. The SAIFI is defined and calculated per IEEE and EEI standards. (*See* IEEE draft standard P1366, dated October 18, 1995.)

4. Objective Line: A goal cooperatively set by the Company and PUC Staff. *See note, pages 11-12 .

5. Revenue Requirement Reduction Threshold: A specific number of interruptions for the average Oregon customer set annually. *See note, pages 11-12 .

6. Revenue Requirement Reduction Line 2: A specific number of hours for the average customer set annually. *See note, pages 11-12 .

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the set number of interruptions. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

7. Company Responsibilities: Company shall furnish annual R2 measure mentioned in data source (item 2 above) by May 15 of the following year.

***NOTE:** ScottishPower agrees that its merger commitment in UM 918 to achieve a 10% improvement by 2005 in SAIDI and SAIFI should be taken into account by the Commission in the establishment of Revenue Requirement Reduction (RRR) lines 1 and 2 for years 2005 through the end of the SQM term. The adjustment of the RRR lines shall also separately take into account any long-term improvements that would have been achieved absent the merger. Items such as the improved vegetation management program (initiated in 1998) and improvements attributable to implementation of OAR 860-023-0080 through 0160 (effective 1/1/98) shall be included in this consideration.

MEASURE R3 -- AVERAGE CUSTOMER MOMENTARY INTERRUPTION FREQUENCY

1. Description: The R3 measure is the weighted average of the last three years momentary interruption frequency indices ($MAIFI_E$). The $MAIFI_E$ index is the number of momentary interruptions that an average customer experiences during the year.

   ScottishPower commits to developing improved methods to measure MAIFI and MAIFIe for individual customers. ScottishPower and OPUC Staff recognize the technical difficulty in achieving this objective, and will cooperate to insure that cost effective measurement is achieved. ScottishPower will develop a program, which will make use of field trials both in the USA and UK, and present their recommendations on how best to proceed, including associated implementation costs, to Staff by December 31st, 2001. The program and costs will be agreed with Staff prior to implementation. The resulting implementation will be completed by year-end 2004, unless a mutually agreeable alternate deadline is established.

2. Data Source: Company records, data, and reports. This measure shall be implemented as detailed below:

   a. 1998 - A sample-based estimate and actual data of this measure will be part of the Company report.
   b. 1999 - Actual data is collected for this measure with trial objective and revenue requirement reduction lines set.
   c. 2000 - full implementation.

3. Measure Calculation: The R3 measure is a three-year weighted average of the $MAIFI_E$ reliability indices experienced by the Company's Oregon customers. This average is calculated by adding together the target year at a 50 percent weighting factor, the preceding year at a 30 percent factor, and the second preceding year at a 20 percent factor. The $MAIFI_E$ is defined and calculated per IEEE draft standard P1366, dated October 18, 1995. This index excludes interruptions that are greater than 5 minutes in length, and excludes

momentary interruptions that are included in a single relay sequence that results in breaker lockout (extended outage).

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Threshold: A specific number of interruptions for the average customer set annually.

6. Revenue Requirement Reduction Line 2: A specific number of interruptions for the average Oregon customer set annually.

7. Revenue Requirement Reductions: Revenue requirement reductions shall be assessed for any year that the measure is above the revenue requirement reduction threshold. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options. (See Summary Table 2).

8. Company Responsibilities: Company shall furnish annual R3 measure value, as detailed in 2 and 3 above, by May 15 of the following year.

MEASURE R4—ANNUAL SERVICE RESTORATION INDEX

1. Description: The R4 measure is the average time (hours) required to restore service to the average customer per sustained interruption, exclusive of Major Events. This is based on an industry index; Customer Average Interruption Duration Index (CAIDI).

2. Data Source: Company's reliability records, data, and certified reports.

3. Measure Calculation: The R4 measure is a calendar year's percentage of all Oregon customer sustained interruptions that have been restored within 3 hours of the outage initiation. Major Events are excluded.

4. Objective Line: A goal cooperatively set by the Company and PUC Staff.

5. Revenue Requirement Reduction Threshold (RRR 1): A specific duration in hours for all Oregon customer sustained interruptions, on average, on an annual basis.

6. Revenue Requirement Reduction Line 2 (RRR 2): A specific duration in hours for all Oregon customer sustained interruptions, on average, on an annual basis.

7. Revenue Requirement Reductions: Revenue requirement reductions

shall be assessed for any year that the measure amount is a higher hourly time than the set Revenue Requirement Reduction line. The revenue requirement reductions shall be determined by the Commission based on circumstances and revenue requirement reduction range options (see Summary Table 2).

8. Company Responsibilities: Company shall furnish an annual R4 measure value mentioned in data source (item 2 above) by May 15 of the following year.

MEASURE S1 -- MAJOR PUC SAFETY VIOLATION PERFORMANCE MEASURE

1. Description: The S1 measure indicates the number of major safety violations cited by the Commission that were in effect during the year. The revenue requirement reductions associated with this measure are to acknowledge the fact that customers have paid for adequate maintenance in their rates and that a major safety violation is a reflection that the Company should recompense customers in some manner for the safety situation cited.

2. Definition: A "major safety violation" involves a pattern of serious unsafe conditions or circumstances that put the public, customers, or lineworkers at serious risk of injury, and involves noncompliance with the National Electrical Safety Code (NESC) rules numbers 121, 214, and 313. The three rules address the Company's responsibilities to inspect, test, and maintain their power-line facilities so that they are kept in a safe condition. Also, a "major safety violation" could involve any failure by the Company to comply with OAR 860-028-0005 in reporting personal injury incidents.

   Should PUC Staff determine that the Company has committed a major safety violation, Staff will present its recommendation to the Commission. Should the Commission authorize issuance of a citation alleging a major safety violation, the Company will be afforded an opportunity to present evidence at hearing under the provisions of ORS 756.515 contesting the alleged violation or violations and evidence of any mitigating factors that the Company contends should be considered by the Commission in determining whether to assess the full revenue requirement reduction assessment or a lower amount. A major safety violation must be determined to have occurred by Commission order.

3. Data Source: Commission records.

4. Revenue Requirement Reduction Threshold: 0.0 major safety violations.

5. Revenue Requirement Reduction Calculation: For each major safety

violation cited by the Commission the following will apply:

a. If the Company can demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the Company shall set aside the amount to be determined by the Commission up to $0.1 million in revenues it has received from its customers for disposition by the Commission.

b. If the Company cannot demonstrate, to the Commission's satisfaction, that the major safety violation cited was corrected within 14 days of receipt of the proposed citation by PUC Staff, and if the Commission deems that a major safety violation has occurred, the Company shall set aside the amount to be determined by the Commission up to $0.5 million in revenues it has received from its customers for disposition by the Commission.

c. The maximum assessment for any one major safety violation is $0.5 million.

d. This measure does not have a maximum revenue requirement reduction amount.

MEASURE X1 -- VEGETATION MANAGEMENT PROGRAM AND SERVICE PERSONNEL COUNT (OREGON)

1. Description: The Vegetation Management Program is a Basic Maintenance Program that is set apart from the other I & M programs due to the crucial effect trees can have on system safety and reliability. Trees and other vegetation are trimmed or removed to provide line clearance and prevent system damage. The service personnel count is a valuable early warning indicator to alert Staff of the Company's ability to adequately maintain it's system.

2. Required Interval: Trimming is accomplished on a four-year cycle, with 25% of the system trimmed annually. Moreover, an additional 25% of the system is interim trimmed two growing seasons following cycle trimming. For this portion each feeder or grid is inspected, and trees that cannot hold for a full cycle and any danger trees that may have developed since the last trim cycle, are identified and removed or trimmed to last until the next scheduled cycle.

3. Company Quality Control: Not less than 10% of recently completed tree trimming is inspected on a continuous basis to ensure compliance to the Program Plan and achievement of adequate clearance.

4. Program Expenditures: Annual budget with actual versus planned

expenditures. Information will include total budget and the underlying components of routine maintenance trimming; hot-spot trimming; and off-map trimming such as customer requests, minor storm work, capital construction trimming; and administration.

5. Budgeted Personnel Information (Oregon) for the following positions (FTEs): Company Foresters; Average number of Contract Tree Crews (including total FTEs); Customer Service Associates; Engineering Services (field engineers and estimators); Field Services (line crews overhead and underground, servicemen, supervisors, contract crews (specify)); Substation employees (crews, technicians, inspectors, supervisors (specify)) Metering employees (shop, testers, supervisors (specify)).

6. Data Source: Company records, data and reports. Staff data review and field review.

7. Measure Calculation: There is no individual measure calculation. An annual report with Staff comments and recommendations will be submitted to the commission each spring (May 15) for their review and any action deemed appropriate. Program problems will normally result in NESC violations being cited by PUC Staff with extensive problems resulting in a major PUC Safety Violation (Measure S1).

MEASURE X2 -- BASIC INSPECTION AND MAINTENANCE PROGRAMS

I. INSPECTION AND REPAIRS

A. Pole and Overhead Facilities

1. Description: Inspection and treatment of all Company-owned distribution and transmission poles and overhead distribution facilities. All Company-owned poles are intrusively inspected for strength. Distribution equipment attached to any pole is inspected, repaired, or replaced to ensure the electrical system remains in good working order and meets the National Electric Safety Code (NESC). The first cycle is completed in 1998. The second cycle begins January 1999.

2. Required Interval: 10-year cycle, 10% annually with no individual year falling below 8.5%. Repairs or replacement completed promptly. Repairs are designated "A" (immediate hazard), requiring correction within 30 days, or "B," requiring correction within approximately one year but in no case extending beyond the calendar year following the year of discovery.

3. Company Quality Control: Inspection by appropriate random sample to ensure accuracy of inspection. Minimum 5% of facility points that have been detail inspected are inspected as needed to ensure NESC

compliance during each year.

4. Program Expenditures: Annual budget figures to include: (a) Pole and Overhead Facilities Inspection and Pole Treatment; and (b) Repair and Replacement of Facilities

B. Safety Survey

1. Description: A drive-by survey of the distribution system. The survey is designed to spot incidental damage to the system (such as damage from stormy weather) that neither caused an outage nor was reported.

2. Required Interval: 2-year cycle with 50% of the system driven yearly.

3. Company Quality Control: Random sample by supervisory personnel or their designees to ensure uniform results and adherence to the plan and accuracy of survey.

4. Program Expenditures: Planned and actual annual budget.

C. Underground Facilities:

1. Description: Inspection program includes a thorough visual inspection of underground vaults, pad-mount transformers, switches, and an infrared inspection of all accessible terminals and splices. The first cycle starts in 1998.

2. Required Interval: 4-year cycle, 25% of the system annually with no individual year falling below 20% of the system.

3. Company Quality Control: Inspection by appropriate random sample to ensure accuracy of inspection.

4. Program Expenditures: Annual budget figures to include: (a) Facilities Inspection, and (b) Repair and Replacement of Facilities.

D. Substation Safety

1. Description: Inspection of each substation on the Transmission and Distribution system. The survey is designed to spot vulnerability of intrusion of the enclosure fences, NESC compliance, incidental damage to substation equipment, and the operational condition of the system.

2. Required Interval: 1-month cycle for all substations' security inspections and 3 month cycle for operational inspections.

3. Company Quality Control: Random sample by supervisory personnel or designee to ensure accuracy of survey.

E. Marina Inspection Program

1. Description: Inspection of Company facilities at every marina in Oregon service area.

2. Required Interval: Annually.

3. Company Quality Control: A random sample is reinspected by the supervisor or designee to ensure accuracy of inspection and NESC code compliance.

F. Major Equipment Maintenance

1. Line Equipment:

   a. Pole Top Reclosers and Sectionalizer Program: Inspection of oil-filled reclosers, vacuum reclosers and sectionalizers.

      (i) Required Interval: The equipment is inspected every two years.

      (ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

   b. Pole Top Voltage Regulators Program: Inspection of these devices.

      (i) Required Interval: Voltage regulators are inspected every two years.

      (ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

   c. Switch Program: Inspecting all Company-owned pole-mounted distribution switches.

      (i) Required Interval: 5-year cycle with the first cycle starting in 1998.

      (ii) Company Quality Control: The program is controlled by an operations manager who ensures implementation and coordination.

2. Substation Equipment

    a. Batteries: Batteries are maintained to assure adequate voltage level is present to operate breakers, protective relaying and motor operators during adverse weather conditions and emergencies to assure safety and system reliability.

        (i) Required Interval: Inspected on a 3 month cycle. Company will annually provide the PUC Staff the next year's testing objectives and comparison of previous years objectives to the actuals.

        (ii) Company Quality Control: Post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

    b. Capacitor Banks: The quarterly operational inspection includes a visual inspection to identify damaged or failing capacitors.

    c. Breakers: Breakers must operate upon demand to protect the public in emergencies or fault conditions to assure safety and system reliability and allow efficient operation of the system.

        (i) Required Interval: Company will annually provide the PUC Staff the next year's objectives and comparison of the previous years objectives to the actuals.

        (ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or their designee to assure adherence to the objective which result from the Company's Substation Maintenance Standards.

    d. Disconnect Switches & Connectors: Maintained to assure ability to safely operate the system, and provide safe working clearances.

        (i) Required Interval: Annual Infra-Red inspections performed on selected devices to identify any potential problem for corrective maintenance.

        (ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or their designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

e. Load Tap Changers (LTCs): Maintain system voltages within a desired operating band to assure reliable service and customer equipment performance.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous years objectives to the actuals.

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

f. Regulators: Maintain system voltages within a desired operating band to assure reliable service and customer equipment performance.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous years objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives that result from the Company's Substation Maintenance Standards.

g. Transformers: Transformers provide the means to most efficiently and cost effectively move electrical energy from source to point of use. They are maintained to assure the most capital intensive substation equipment's life is maximized while assuring system reliability.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous years objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

h. Protective Relaying: Relays are maintained to assure adequate protective actions occur to trip faulted equipment and lines in abnormal conditions and emergencies to assure safety and system reliability.

(i) Required Interval: Company will provide the PUC Staff the next year's objectives and comparison of previous years objectives to the actuals

(ii) Company Quality Control: Random sampling of field activities and post completion reviews of testing results by Supervisory personnel or designee to assure adherence to the objectives which result from the Company's Substation Maintenance Standards.

3. Meters

Company shall comply with meter accuracy requirements and testing schedules required by OAR 860-023-0015 and approved by the Commission.

Company shall provide an annual Oregon certification report and presentation to the PUC Staff by May 1 about the previous year's metering program. The certification report shall include information about metering inspections for proper installations, safety, security, and energy diversion, and meter accuracy testing for Oregon meters. Further, the report shall contain summary information on metering program accomplishments, issues, trends, failed meter groups and types, meter repairs and retirements, program modifications, and new applied technologies. Additionally, the certification report shall include the number of Oregon meter tests, inspections and change-outs planned for the current year.

All electric meters and associated equipment and utilization shall comply with applicable requirements of the National Electrical Safety Code (NESC), National Electric Code (NEC), American National Standards Institute (ANSI), and other standards adopted and published by the Commission. Additionally such equipment shall comply with the Oregon Electric Service Requirements Manual (published jointly by PacifiCorp and Portland General Electric), the Electric Utility Service Equipment Requirements Committee (EUSERC), and the Company's Meter Standards Manual.

a. Company Quality Control: Random sample by supervisory personnel or their designee to ensure uniform results and adherence to the plan and accuracy of data.

II. STANDARDS AND STANDARD PRACTICES

A. Company Standards including standard practices are necessary to ensure compliance with NESC, NEC, Company tariffs, PUC laws and good engineering practice. Annual reviews and quality control of the below standards are necessary to ensure that they remain current and are being uniformly implemented in the field:

Electric Service Requirements

Joint-Use Standards

Construction Standards

Design Standards

Operation and Maintenance Standard Practices

Quality Control Program

Power Quality Standards and Practices

ScottishPower will ensure that Staff is kept informed of material changes to policy covered by Standards and Standard Practices of the X2 measure of the SQM previous to their implementation, and that copies of amendments are provided to ensure service manuals are consistently maintained up-to-date with the Commission. This will include Power Quality Standards and Practices developed to provide a framework to implement ScottishPower's Customer Guarantee 8.

B. Required Interval: Annual and other needed reviews of the above standards by Company Standards Department to resolve standards issues associated with customer complaints, joint-use conflicts, PUC enforcement actions, code and regulation changes, etc.

C. Company Quality Control: Annual review by Company standards engineer to ensure that the above standards are updated. Random sample by standards personnel to ensure uniform results and adherence with the standards in the field.

MEASURE X3 -- SPECIAL PROGRAMS

1. Special Programs address specific issues which may effect T&D operation, maintenance or safety. They normally operate for a specific period of time, accomplish their intended purpose, and are terminated upon completion. Information discovered in the program may result in the establishment of specific, routine, ongoing programs.

   An exception is the UM 918 agreement that ScottishPower will provide an ongoing Annual Report on Electric Reliability, which will comply with the reporting requirements of Oregon Administrative Rules 860-023-0080 through 0160, and provide information on commitments and achievements on improving service to 5 targeted underperforming circuits per year.

2. These special programs will be reviewed annually and reported on to PUC

Staff. The list of special programs is expected to change annually.

-Underground Cable Replacement

-Squirrel Guards

-Pilot Programs

-Overhead Notification

-National Joint Utility Notification System

-Powerline Related, Forest Fire Prevention Consortium

REPORTING OF X1, X2, AND X3 PROGRAMS

A yearly Maintenance Program Review Meeting will be held by May 15. Applicable information on each program's accomplishments for the year and plans for the next year will be presented to and discussed with PUC Staff. A written report, both paper copy and on compatible electronic format, will follow this meeting and be presented to PUC Staff that same day. This report will summarize all information presented at the yearly meeting. Semi-annual updates are provided for the X1 measure.

AR 506

STAFF EXHIBIT 6

Oregon Public Utility Commission
Staff Policy

Tree To Power Line Clearances

PURPOSE

The purpose of this policy is to modify and define the tree trimming rules of ANSI C2, National Electrical Safety Code (NESC) as interpreted by the administrative authority (Reference--NESC Rules 012, 013, and 218). This policy is to set forth the specifications and guidelines relating to tree trimming, tree removal, and line clearance to provide for reasonable service continuity, safety to the public, and to guard against forest fire damage caused by supply conductors.

POLICY

Trees which may interfere or do interfere with supply conductors should be trimmed or removed.

A. Specifications and guidelines for line clearances.

1. The necessary clearance of supply lines from trees is determined by:

    a. Voltage, location, and importance of individual line.

    b. The height of the poles and line.

    c. The growth habit and final appearance of the trees.

    d. Combined movement of trees and conductors under adverse weather conditions.

    e. Sag of conductors at elevated temperatures.

2. Concept:

    a. Transmission lines should have a minimum clearance of ten feet in all directions.

    b. Primary distribution lines.

       There should be a minimum 5-foot clearance between an energized high voltage distribution conductor and any part of a tree. This clearance may be reduced to three feet if the tree is not readily climbable (having sufficient handholds and footholds to permit an average person to climb easily without using a ladder or other special equipment).

Trees should be trimmed to the extent that this designated minimum clearance area will be kept free of new tree growth until the next scheduled trimming cycle. If the trimming cycle is other than three years, as may be needed for fast-growing tree species or where limited trimming is permitted by the tree owner, appropriate records need to be maintained to insure timely trimming is accomplished.

Intrusion of limited small branches and new tree growth into this minimum clearance area can be tolerated so long as it does not contribute to a safety hazard to a person climbing the tree or cause interference with the conductors.

c. Secondary and/or service conductors (600 volts and below) should have at least 1-foot clearance. While extensive tree trimming or tree removal relating to these services is not expected, proper consideration must be given to possible conductor damage and service outages caused by trees, and appropriate measures taken.

B. Tree removal. Whenever justified, tree removal should be encouraged. Trees should be removed under the following conditions:

1. Trees located in school yards, playgrounds, parks, backlot construction areas, or other areas and which children may climb easily and contact overhead conductors.

2. Trees that have been topped under low-level primary and transmission circuits with no chance for a reasonable, natural development.

3. Trees that are unsightly because of excessive trimming and cannot be economically retrimmed.

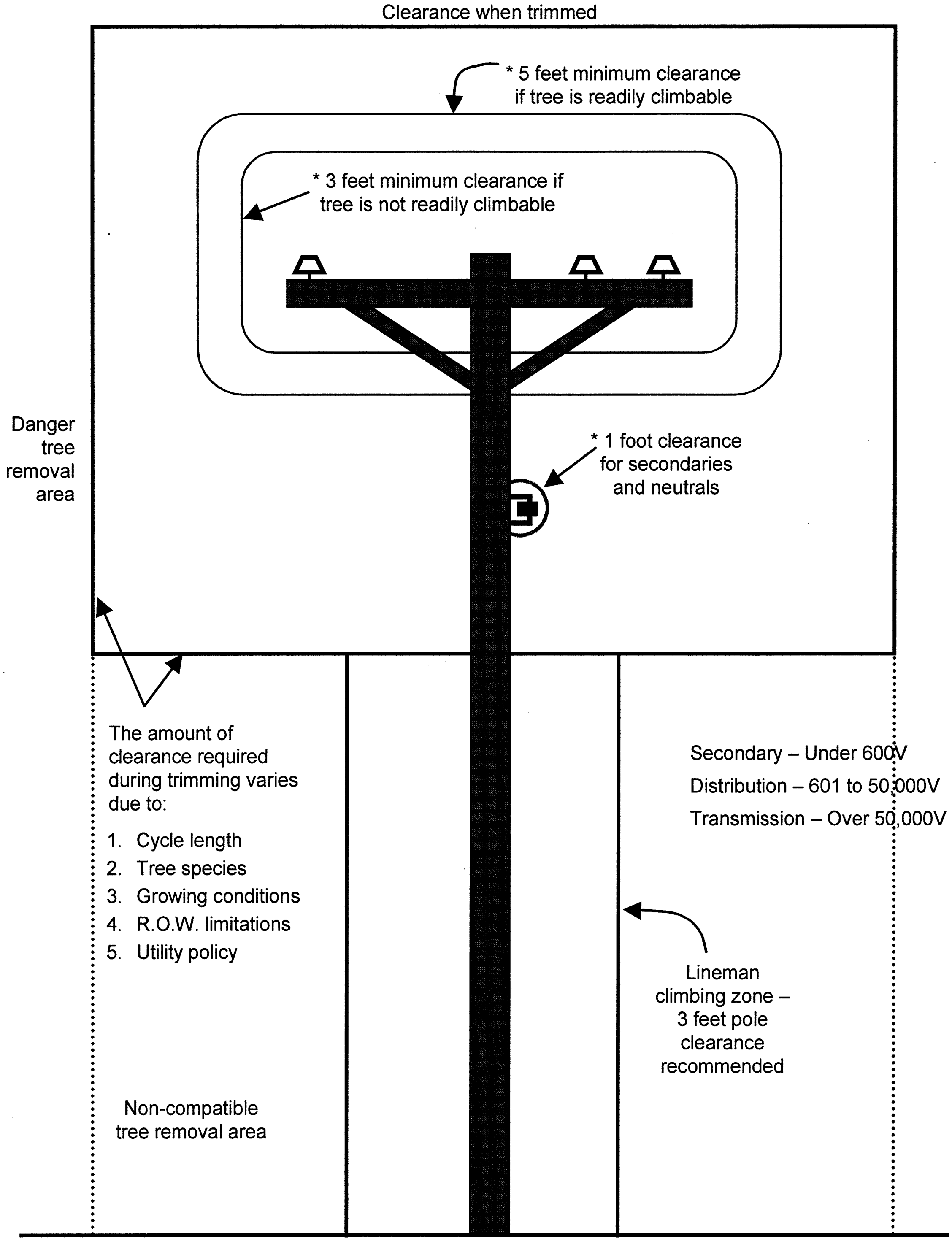
4. Trees in rural areas along county roads and state highways which would eventually reach a primary or transmission line.

5. Fast-growing tree species located in suburban and urban areas, near homes or in landscaped areas which will eventually grow into transmission or distribution lines.

6. Trees, both live and dead, which are leaning toward the line and which would strike the line when falling.

(Issued before 1983; revised Jan. 1987)

Vegetation Clearances for Distribution



1. Note: All voltages are phase to phase, nominal

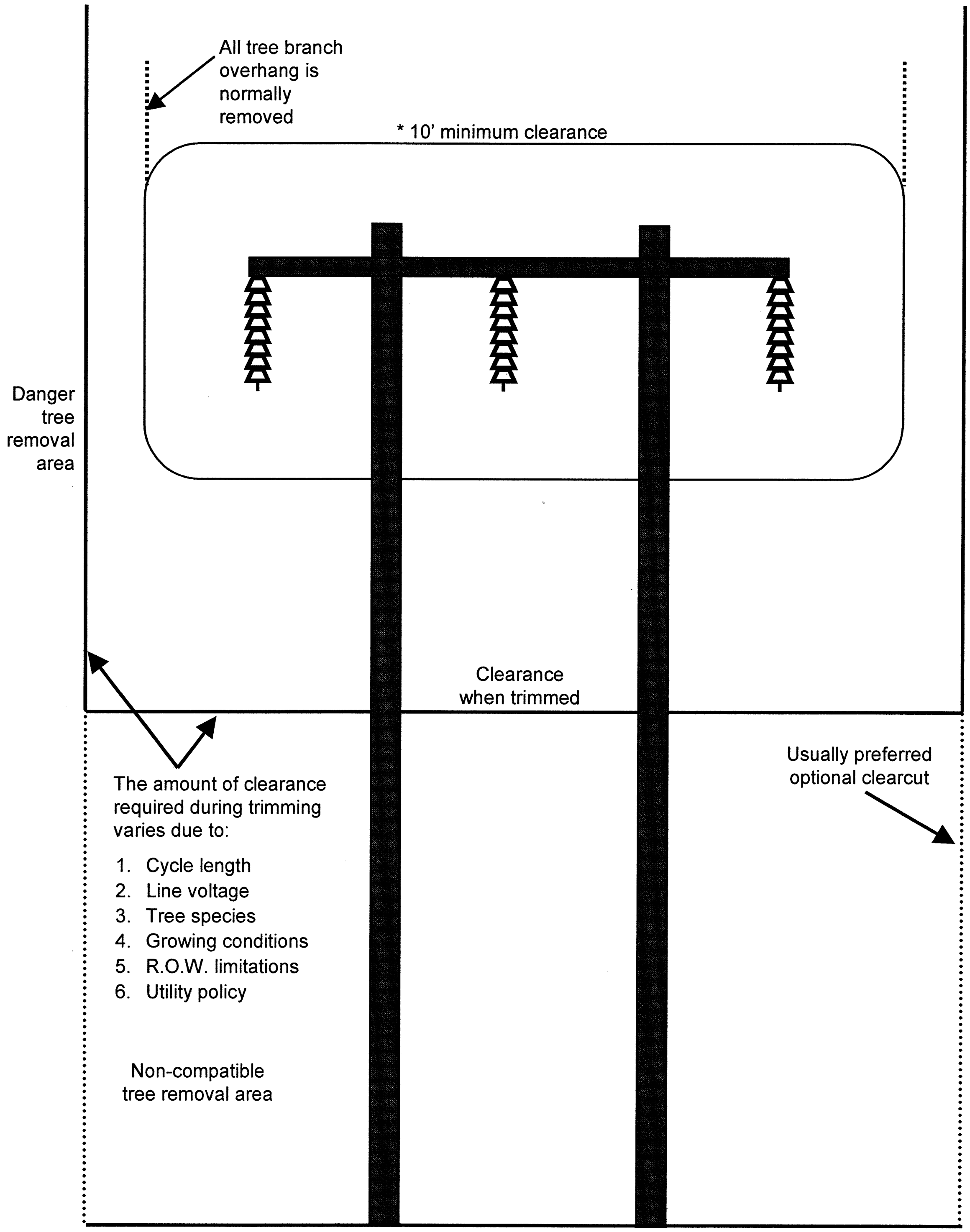
*2. Note: Minimum indicates clearance required at all times.

*3. Note: The motion of poles, conductors and trees under adverse weather conditions must be considered in maintaining minimum clearances.

4. Definition: Readily climbable – Having sufficient handholds and footholds to permit an average person to climb easily without using a ladder or other special equipment.

Rev. 2003

Vegetation Clearances for Transmission



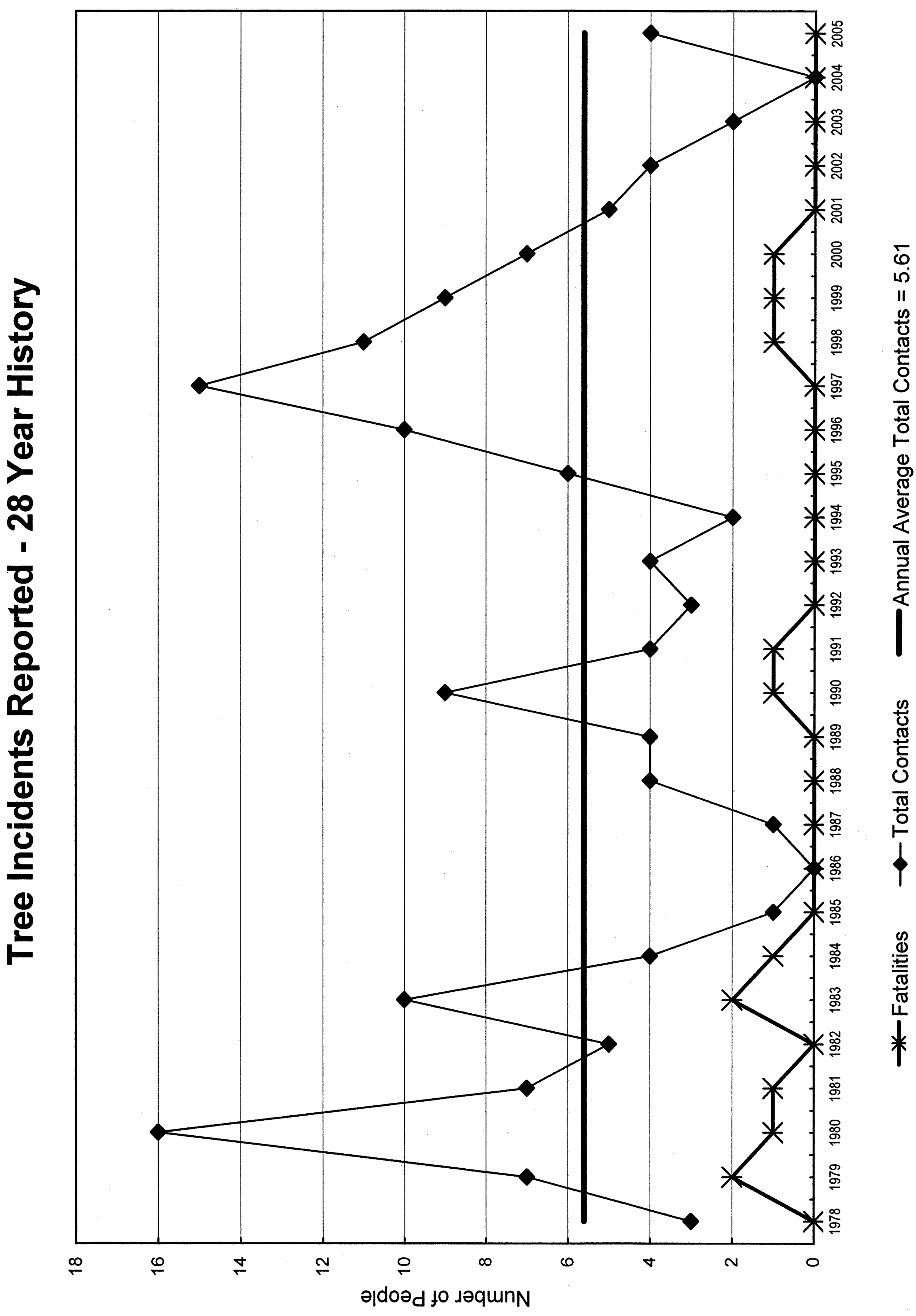
* Note: Minimum indicates clearance required at all times.

* Note: The motion of poles, conductors and trees under adverse weather conditions must be considered in maintaining minimum clearances.

Rev. 2003

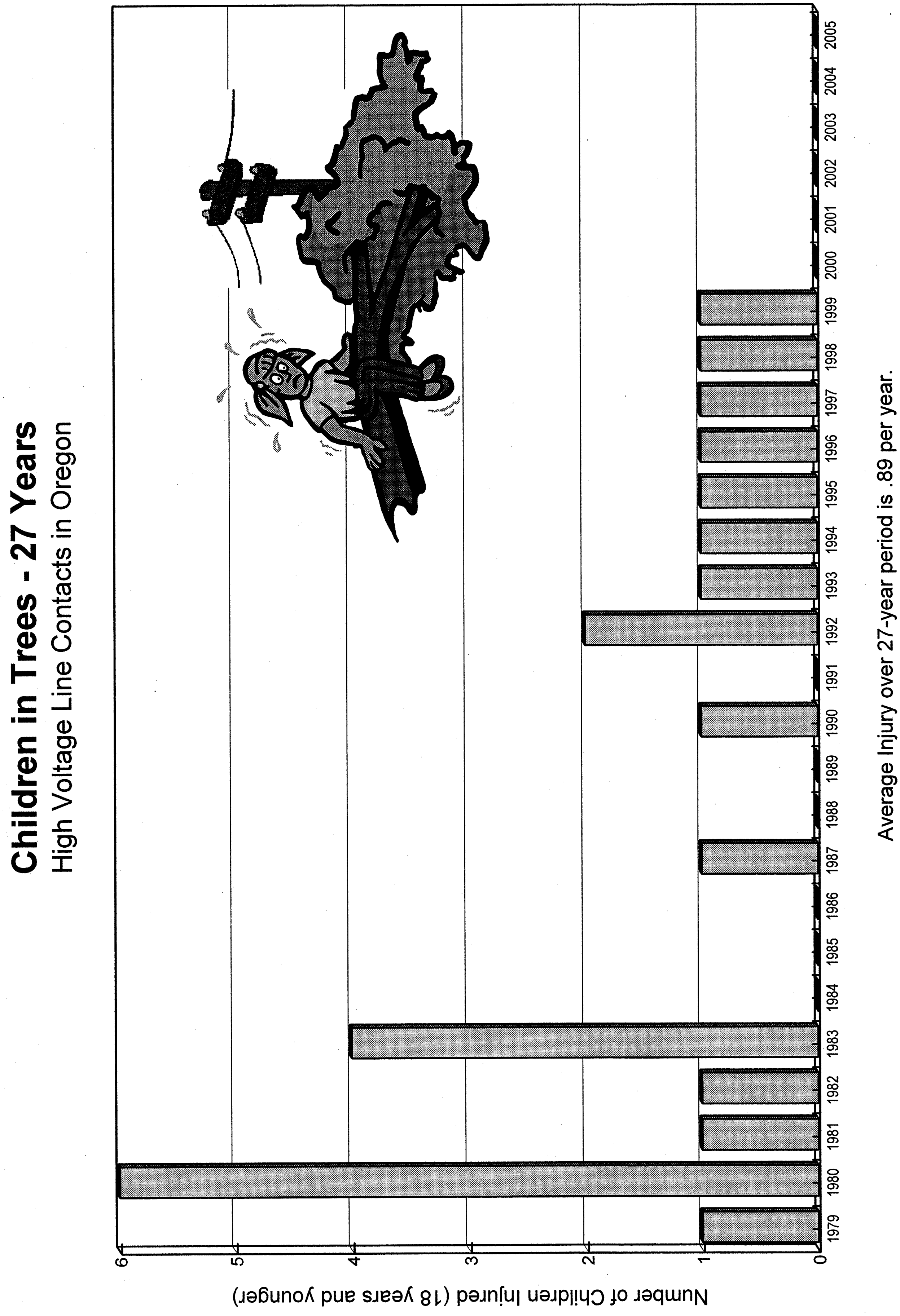
AR 506

STAFF EXHIBIT 7


Tree Incidents Reported - 28 Year History
Number of People
0
2
4
6
8
10
12
14
16
18
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Fatalities
Total Contacts
Annual Average Total Contacts = 5.61

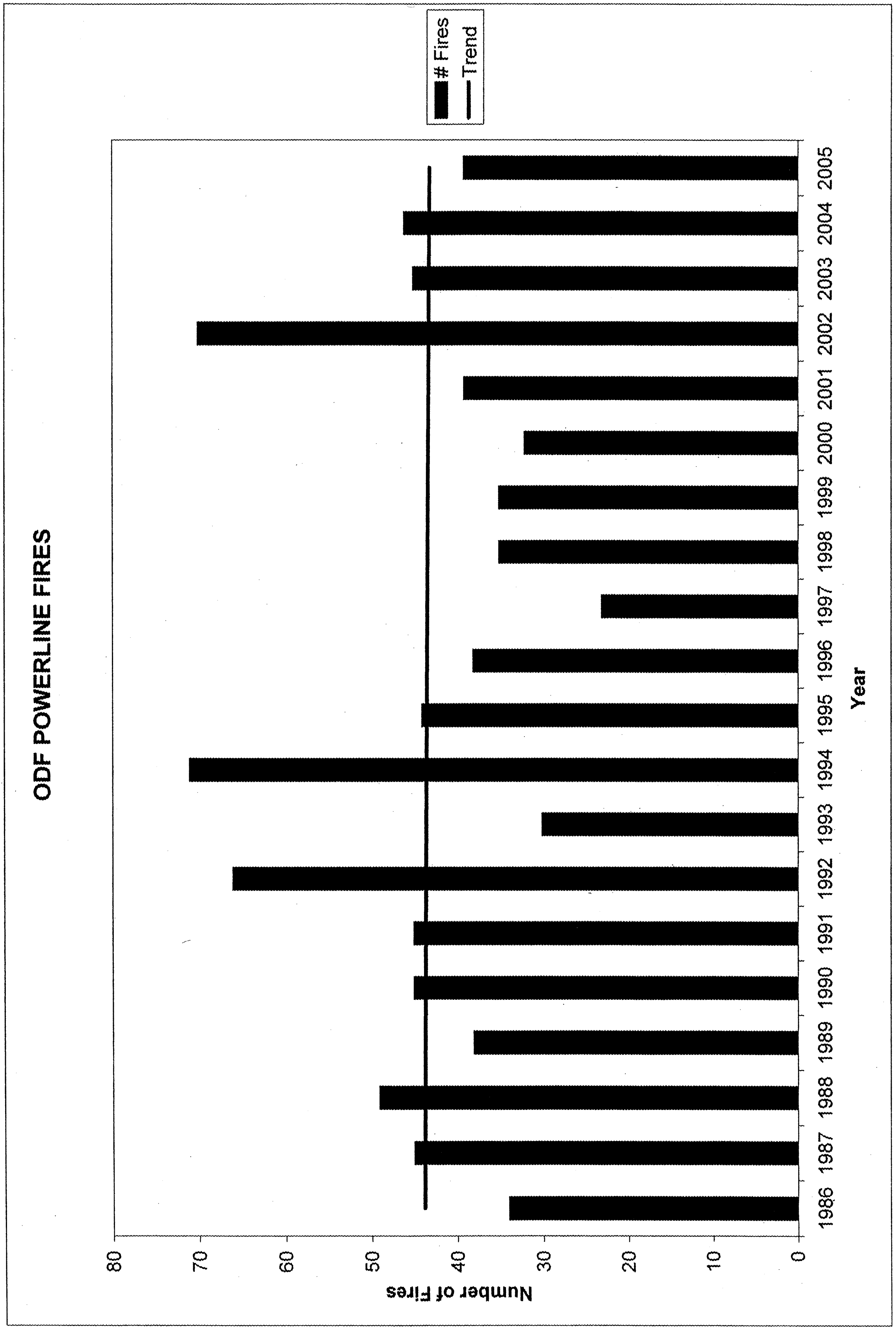
AR 506

STAFF EXHIBIT 8


Children in Trees - 27 Years
High Voltage Line Contacts in Oregon
Number of Children Injured (18 years and younger)
0
1
2
3
4
5
6
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Average Injury over 27-year period is .89 per year.

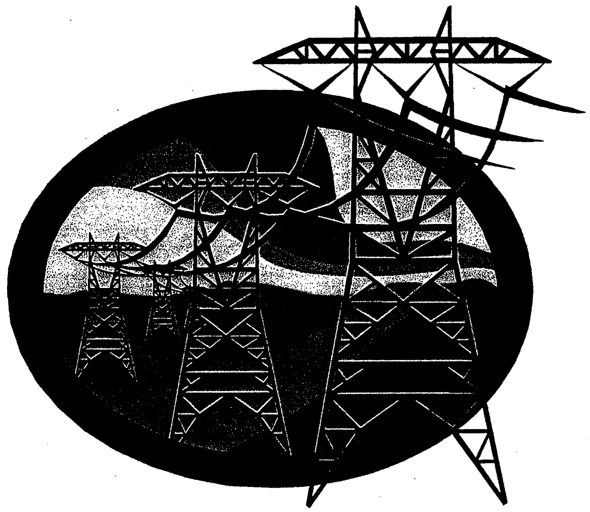
AR 506

STAFF EXHIBIT 9

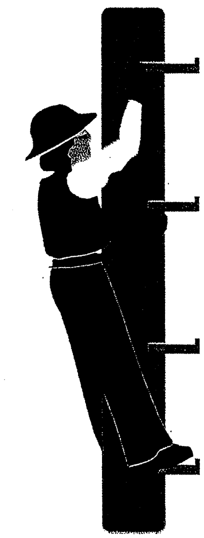

ODF POWERLINE FIRES
Fires
Trend
Number of Fires
0
10
20
30
40
50
60
70
80
Year
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005

AR 506

STAFF EXHIBIT 10



2006 UTILITY ELECTRIC CONTACT REPORT



Personal Injury Electric Contact Incidents to
Utility Workers and the Public
Reported to the Oregon Public Utility Commission in 2005

The Oregon Public Utility Commission does not discriminate on the basis of race, color, national origin, sex, sexual orientation, religion, age, or disability in employment or the provision of services.

This document is available in alternate formats by calling 503-378-8962 (voice), 800-648-3458 (TTY) or electronically via the Oregon PUC Web site at http://www.puc@state.or.us (click on "Safety")

Oregon PUC Public Utility Commission

2006 Utility Electric Contact Report

(For injury incidents reported in 2005)

Report compiled February 2005, by Bob Sipler
Sr. Utility Analyst, OPUC Safety and Reliability Section

Information contact:
Jerry Murray, Utility Safety and Reliability Section
Oregon Public Utility Commission
550 Capitol St. NE, Ste. 215, Salem, Oregon 97301-2551
Telephone: 503-378-6626
Internet: jerry.murray@state.or.us

Table of Contents

	Page
Introduction	1
Chart: Incidents Reported By Electric Utilities – 20 Year History	2
Summary	3
Description of Charts	4
Chart: Injury Severity	5
Chart: Type of Electrical System Involved	6
Description of Charts	7
Chart: When Incidents Occurred - By Month	8
Chart: When Incidents Occurred - By Day of Week and Hour of Day	9
Chart: Demographic Areas: Rural, Suburban, Urban, Industrial, and Construction	10
Chart: Where Incidents Occurred - By Area	11
Area Map	12
Description of Charts	13
Chart: Who Was Involved in Accidents - By Activity Classification	14
Chart: Who Was Involved in Accidents - By Age	15
Description of Charts	16
Chart: Tree-Related – 20 Year History	17
Chart: Crane-Related – 20 Year History	18
Chart: Irrigation Pipe-Related – 20 Year History	19
Chart: Antenna-Related – 20 Year History	20
Breakdown by Activity Involved	21
Chart: Children in Trees – 20 Year History	22
Recommendations to Electric Utilities by the OPUC Safety Staff	23
Target Your Education Efforts	24

Introduction

Incident reporting to the PUC is required by **ORS 654.715** (IOU's), **and OAR 860-024-0050** (all "operators" - defined in OAR 860-024-0001). The PUC Utility Safety and Reliability Staff use this information to help with National Electrical Safety Code (NESC) administration and to promote accident prevention.

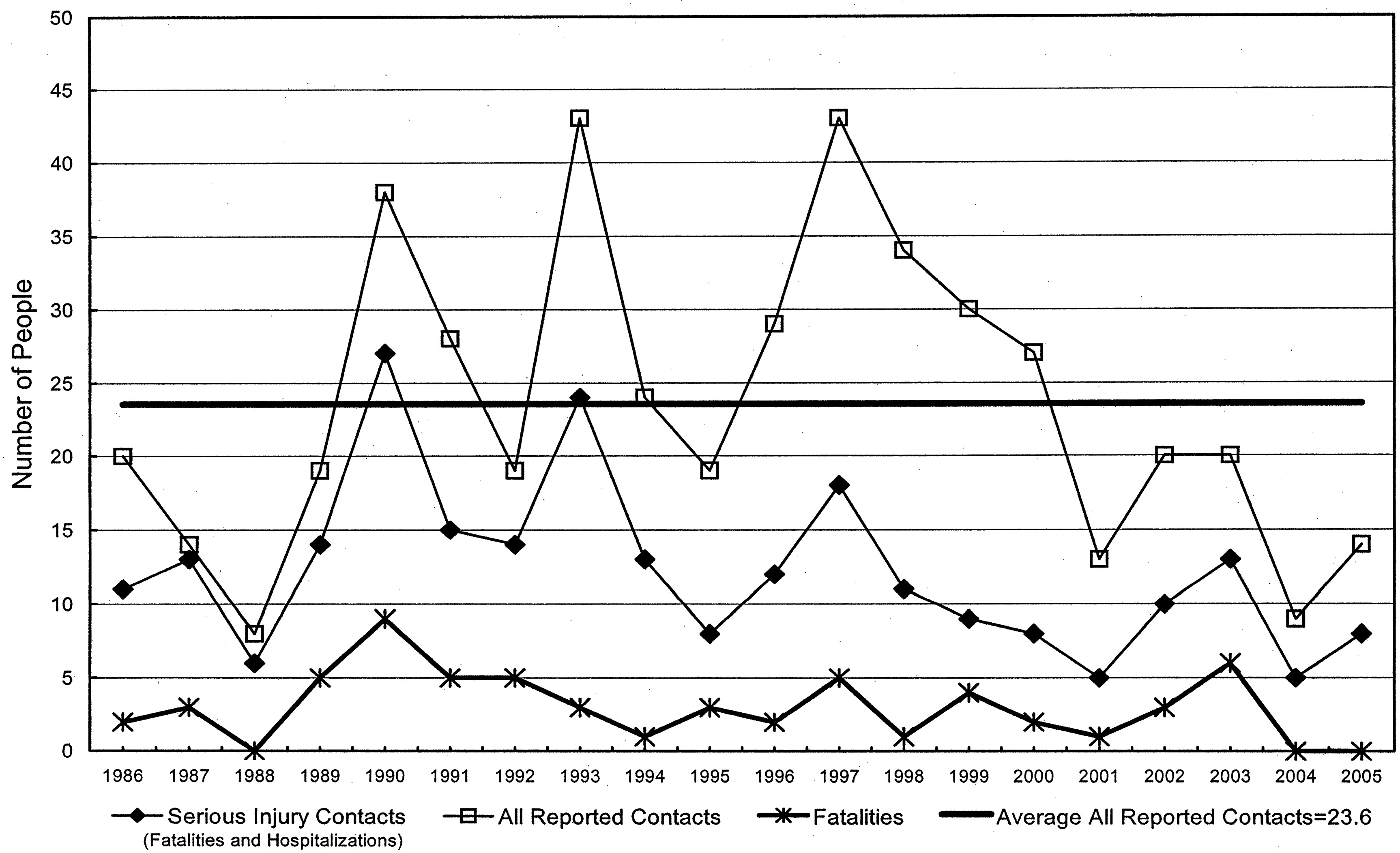
The safe transportation of electric energy includes: building and maintaining facilities to meet a safety code, performing daily operations safely with trained, qualified, and supervised employees and contractors, and protecting the public. The root cause of many accidents is related to an unsafe act, not an unsafe condition. Also, there is often a lack of awareness of the degree of danger. The innocent looking wire that a bird can land on, with impunity, has the potential to end, or change forever, the life of a person who touches it. It is essential that all of us who live and work around power lines understand the danger, the possible consequences, and how to avoid it. The electric utilities have a responsibility to provide this education, to train and supervise employees, and to build and maintain their facilities to comply with the NESC, as required by the Commission's Safety Rules in OAR 860, Division 24.

This report contains a series of written analysis sheets with accompanying graphs. The end of the report contains a summary and recommendations. Electric operators can use this information to more accurately target their public information program and their worker safety training.

(Chart on Page 2)

The first chart shows incident levels since 1986 (20 years). There have been some parallels with the level of past construction activity in Oregon. The graph shows that while 2002 and 2003 were not statistically years with an extreme number of accidents, there were quite a number of serious and fatal injuries recorded. 2004 was one of the best of the last 25 years for a low number of accidents. While there were no fatal injuries in 2005, there were a rising number of total and serious (hospitalization level) contact injuries.

Incidents Reported By Electric Utilities - 20 Year History



*** * * Yes, an average of 23.6 people injured each year! * * ***

Summary

Here are some basic facts for 2005 incidents:

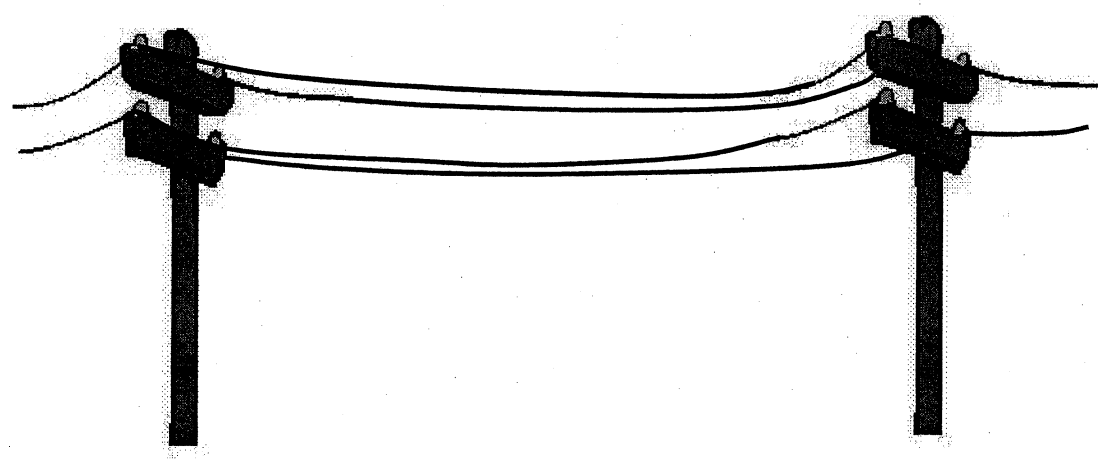
1. Fourteen people were involved in Injury* electrical contacts in separate incidents with electric utility facilities. Eight required hospitalization, six were determined to be minor or non-injury, and there were no deaths.
2. Most of the incidents involved "distribution" voltage (between 600V and 30,000V) overhead wires. (See pg. 6)
3. Most of the accidents in 2005 were work related. This has been true since 1997 except for 2001. In 2005, the largest work related accident category has been associated with home maintenance. Traditionally the predominate cause of non-work accidents has been tree-related. Homeowner tree trimming and felling continued as a large (4) non-work accident cause
4. Historically, most of the contact victims have involved males. An extremely high (3 of the 20) number of women were injured in 2002. All involved vehicles hitting facilities (one airplane and two cars). Again, in 2003, there were three female victims, one when a car hit a pole and two pedestrians who contacted a low wire. All victims in 2004 and 2005 were male.
5. A crane, a cement pumper, and a lift truck were each involved in high voltage line contacts. In addition, two workers using ladders made these contacts.
6. There were four tree-related incidents in 2005.
7. There were four injury incidents involving high voltage underground systems.

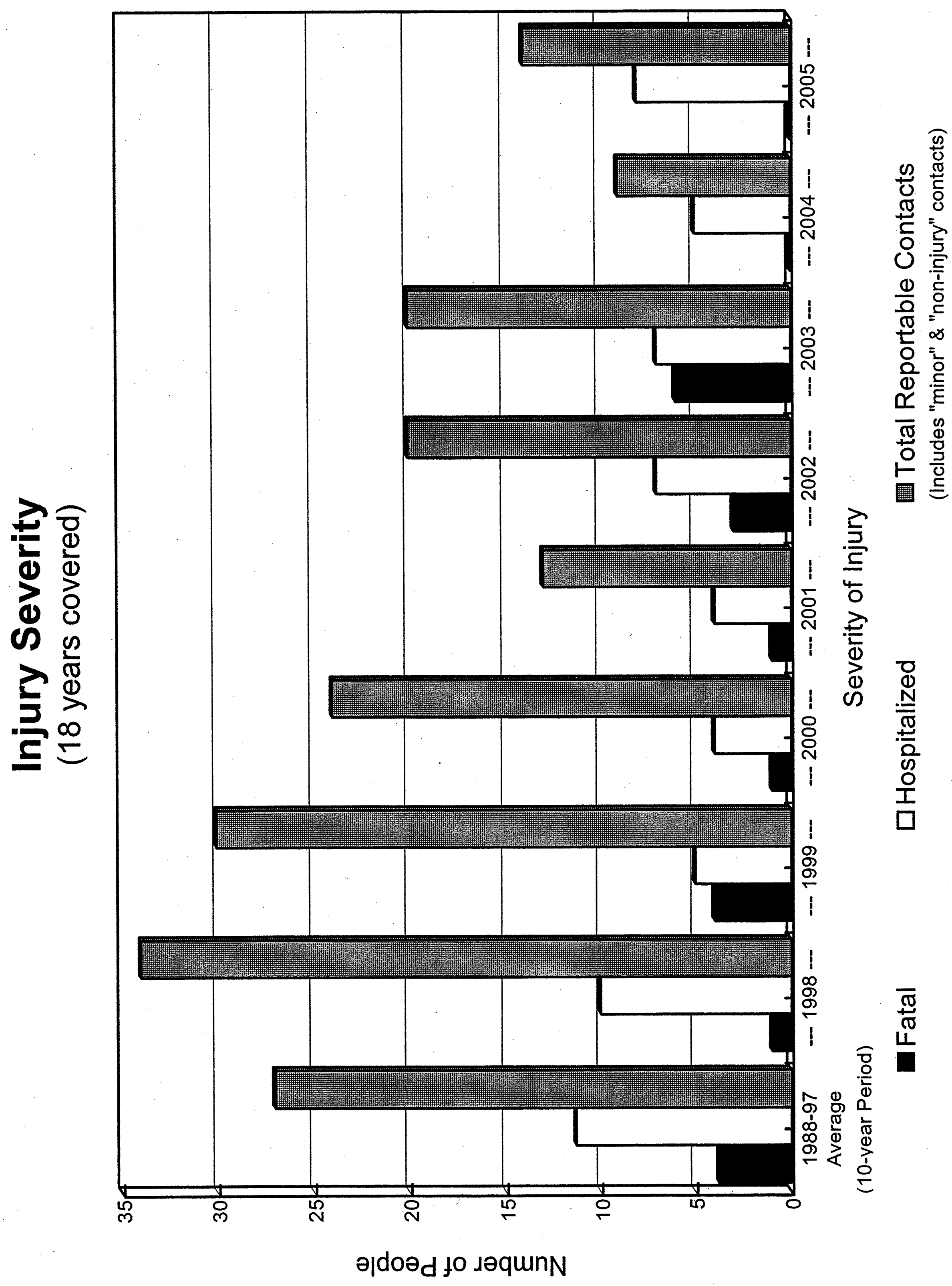
*"Injury" as defined in OAR 860-024-0050. There were additional "reportable injuries" to utility personnel that did not involve electrical contact. These are not included in this report.

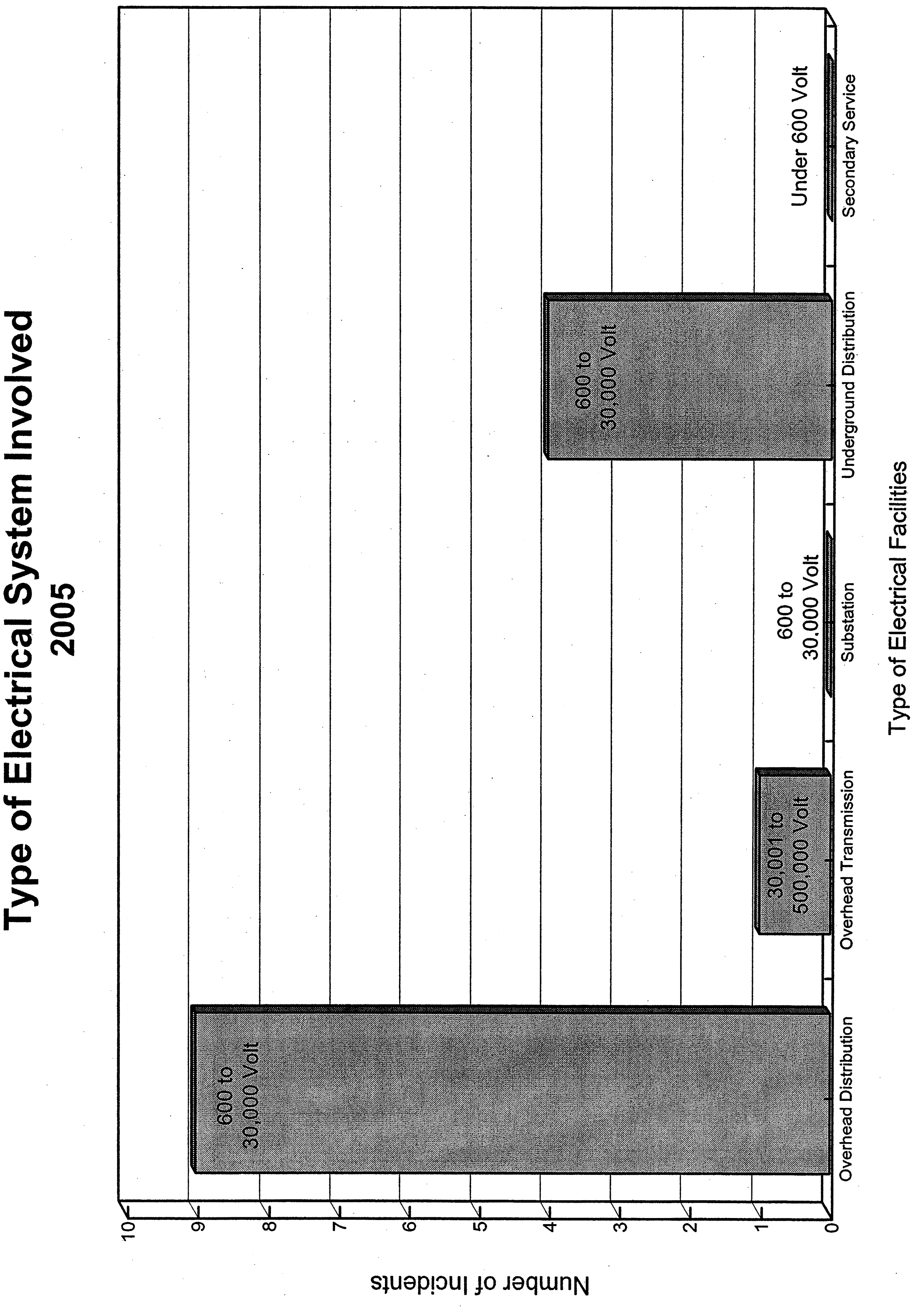
The next two charts show:

- **<u>Injury Severity</u>** - A **"Minor"** injury is usually a trip to the hospital, first-aid-type treatment, and same-day release. **"Non-injury"** cases often involve a person who does not need or refuses any treatment or examination but has had contact with high voltage and has felt a shock. **"Hospitalization"** requires at least an overnight stay for injury treatment. A precautionary, for-observation stay, can be considered a minor injury.

- **<u>Type of Electrical System Involved</u>** - This chart shows that **most** utility electrical incidents result from contacts with overhead distribution conductors. These are the typical high voltage distribution wires found in most neighborhoods and along roads. There was an incident in 2005 that involved a transmission voltage of 115 Kv. Also, there were four underground high voltage accidents.

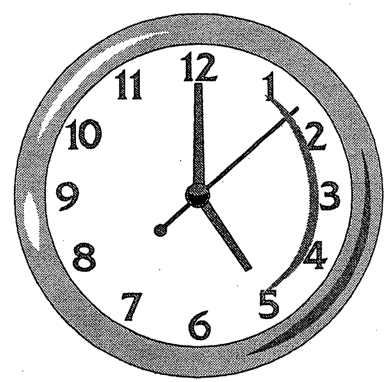



Injury Severity
(18 years covered)
Number of People
0
5
10
15
20
25
30
35
1988-97 Average (10-year Period)
--- 1998 ---
--- 1999 ---
--- 2000 ---
--- 2001 ---
--- 2002 ---
--- 2003 ---
--- 2004 ---
--- 2005 ---
Severity of Injury
Fatal
Hospitalized
Total Reportable Contacts
(Includes "minor" & "non-injury" contacts)

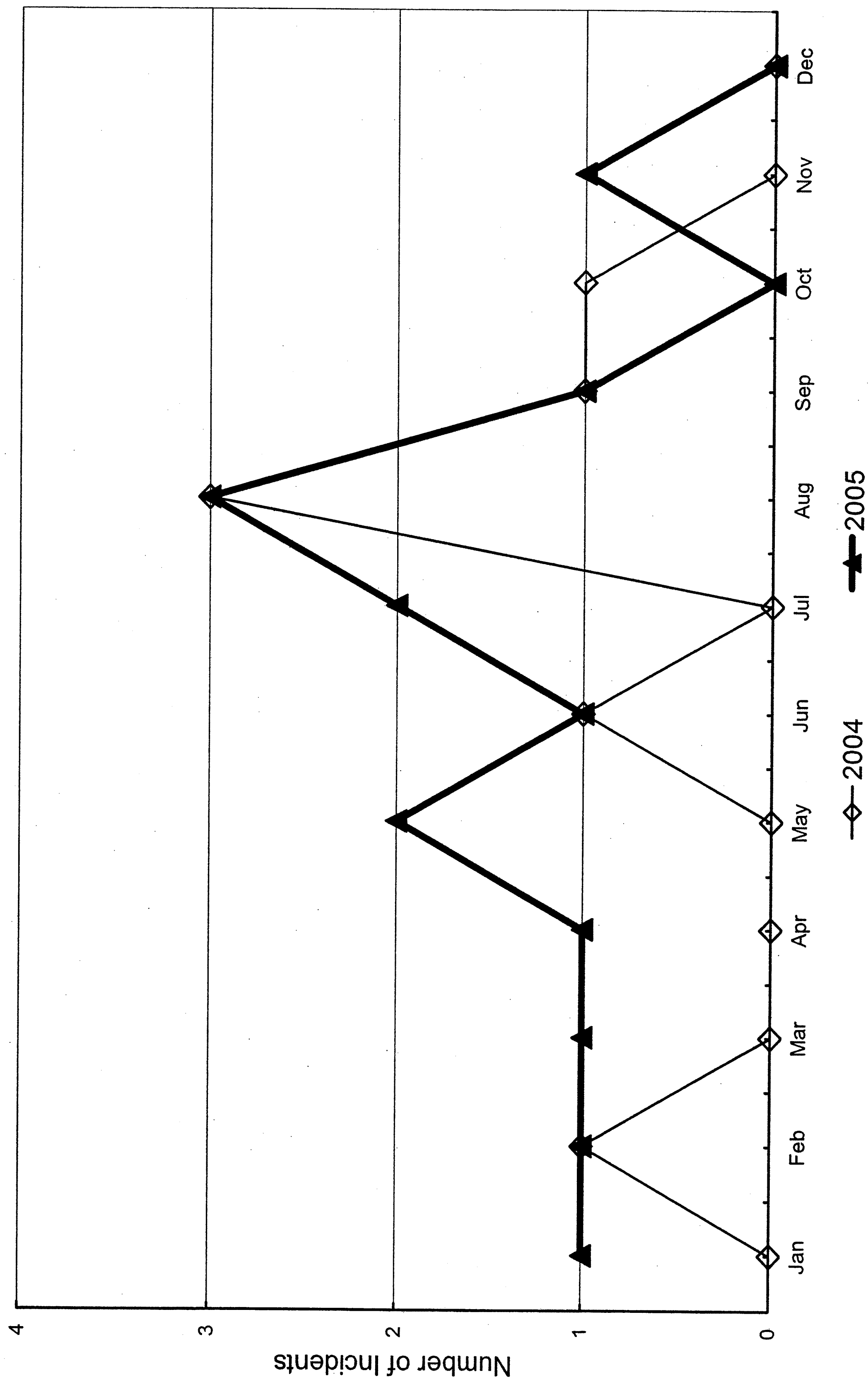

Type of Electrical System Involved
2005
Number of Incidents
0
1
2
3
4
5
6
7
8
9
10
600 to
30,000 Volt
30,001 to
500,000 Volt
600 to
30,000 Volt
600 to
30,000 Volt
Under 600 Volt
Overhead Distribution
Overhead Transmission
Substation
Underground Distribution
Secondary Service
Type of Electrical Facilities

The next two charts relate to <u>When Incidents Occurred</u>:

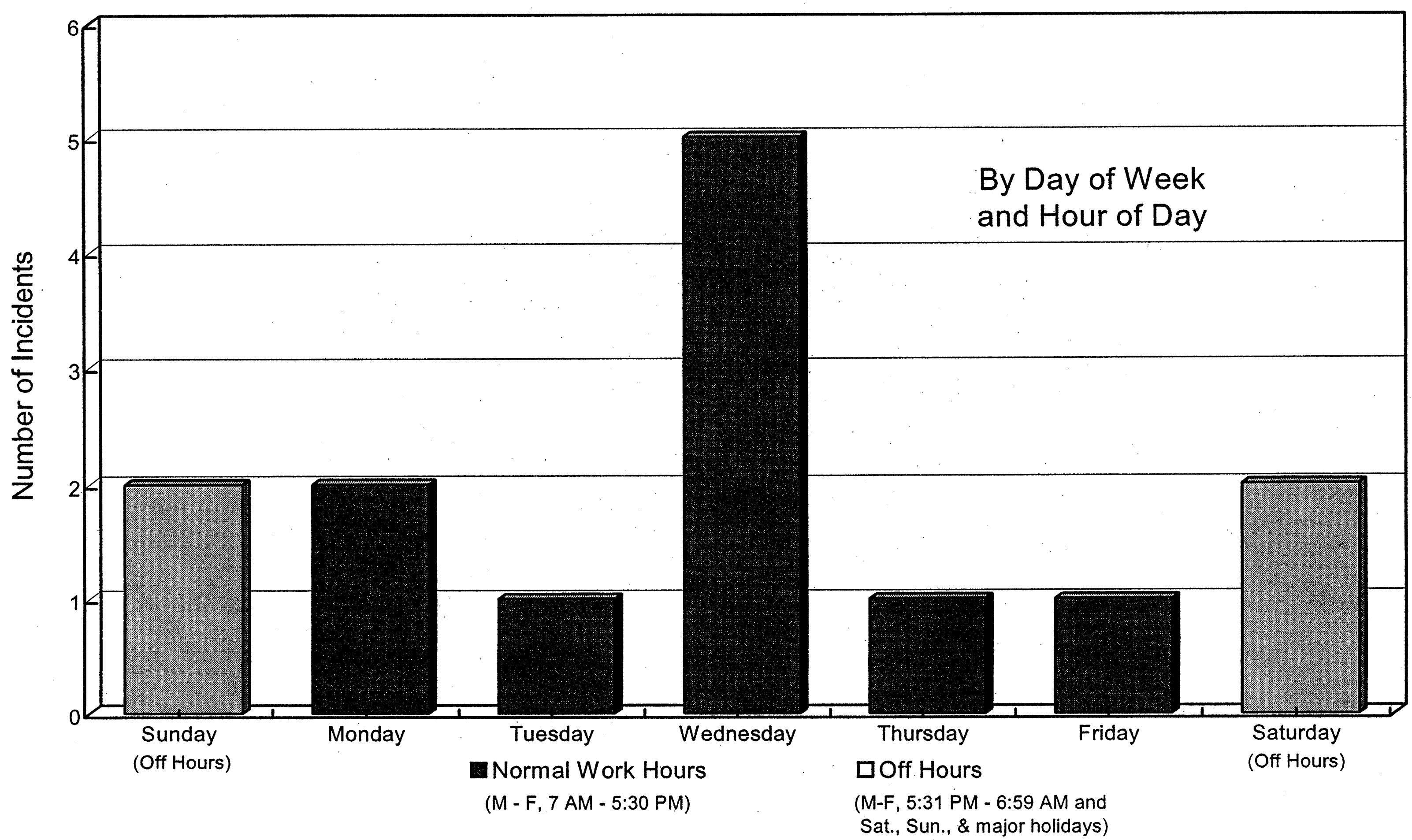
- **By Month** – Incidents in 2004 were higher during the summer months, except July, and more like the typical pattern seen in most years. A somewhat similar pattern is seen in 2005.
- **By Day of Week and by Hour of Day** – This chart shows when incidents generally occurred. Wednesday seems to have been a particularly bad day in 2005 (as it was in 2004).



When Incidents Occurred - By Month



When Incidents Occurred
2005

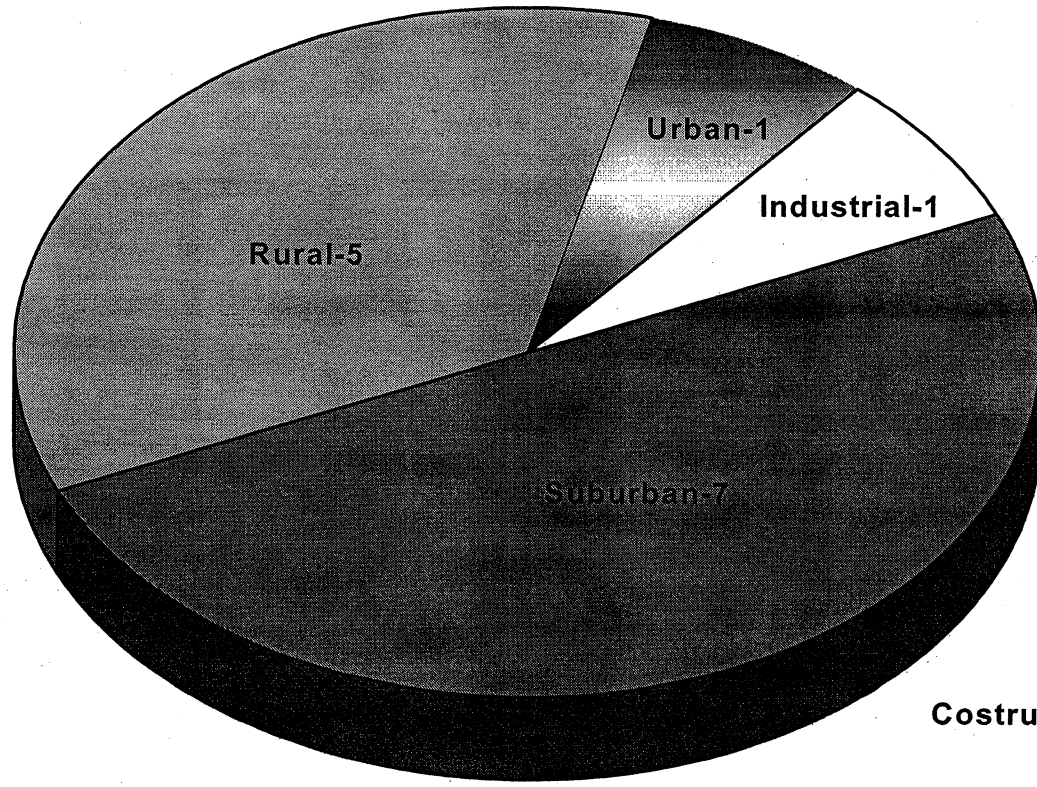


Note: This chart does not indicate the number of work related or home/recreation related incidents. Some work related incidents could have occurred during "off" hours and some home/recreation incidents could have occurred during "work" hours. The total number of incidents did come out close to what is indicated with nine (9) work related incidents and five (5) incidents that were not related to commercial work activities.

The pie chart below indicates where people are injured in regard to

Demographic Areas or Sites: Rural, Suburban, Urban, Industrial, and Construction.

Our statistics show rural areas typically have a higher rate than other types of areas (although not in 2005).



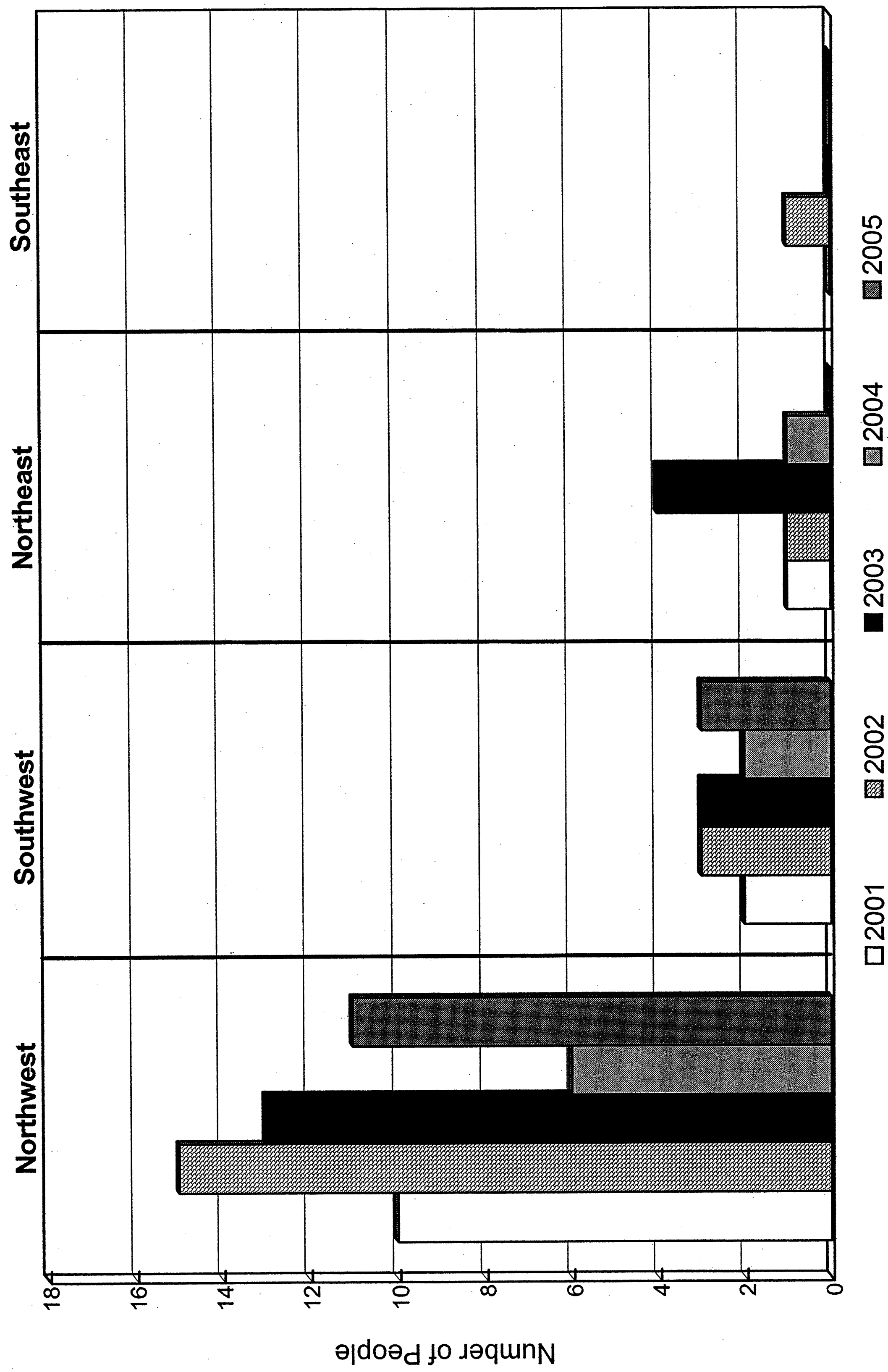
By Person Injured

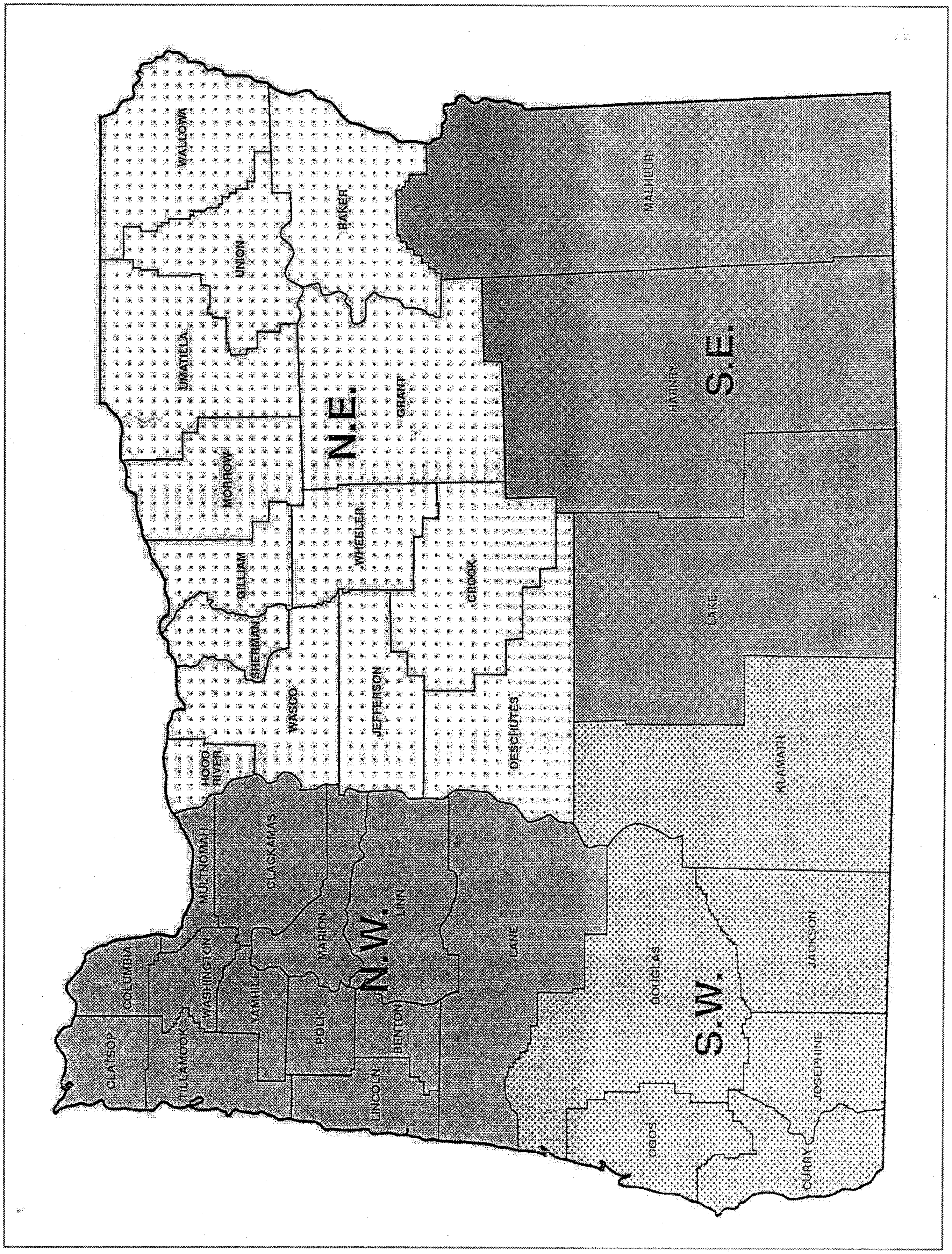
The next chart and map indicates <u>Where Contact Injuries Occurred</u>:

Five time periods are compared: 2001 through 2005.

The most populated area of the state, the Northwest, has historically had the highest incident rate.

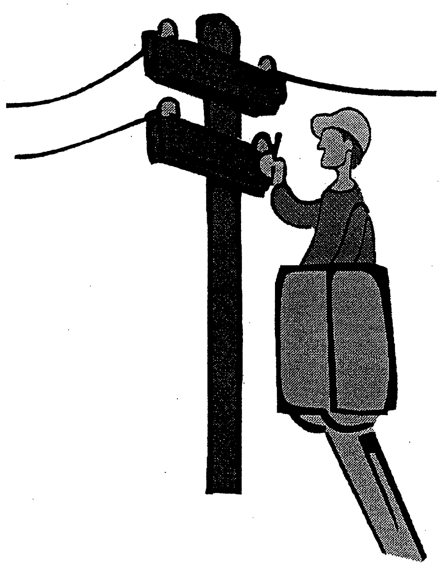
Where Contact Injuries Occurred - By Area



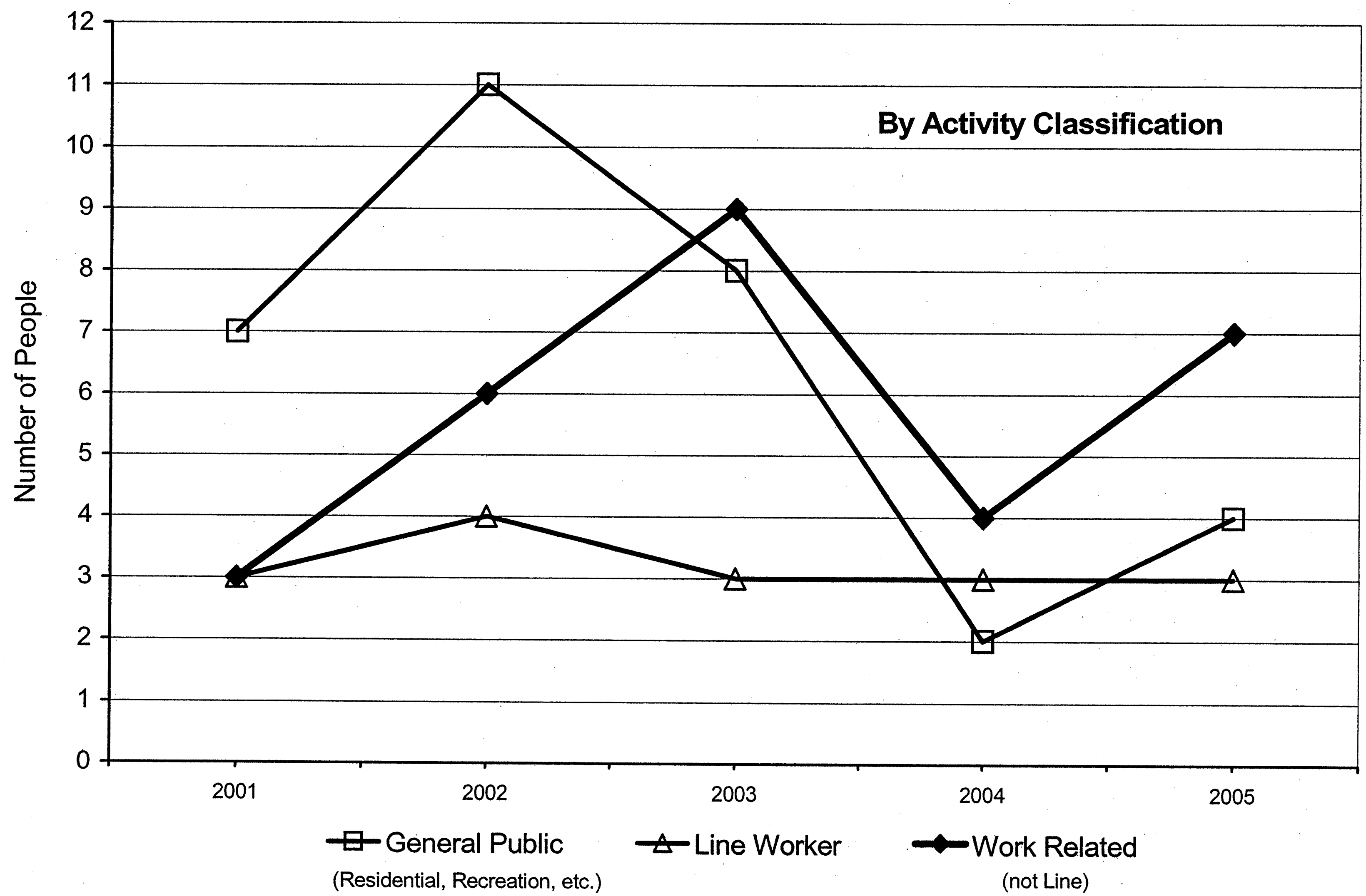

N.E.
WALLOWA
UMATILLA
UNION
BAKER
MORROW
GRANT
GILLIAM
WHEELER
SHERMAN
WASCO
HOOD RIVER
JEFFERSON
CROOK
DESCHUTES
S.E.
MALHEUR
HARNEY
LAKE
N.W.
CLATSOP
COLUMBIA
TILLAMOOK
WASHINGTON
MULTNOMAH
YAMHILL
CLACKAMAS
POLK
MARION
LINCOLN
BENTON
LINN
LANE
S.W.
DOUGLAS
COOS
CURRY
JOSEPHINE
JACKSON
KLAMATH

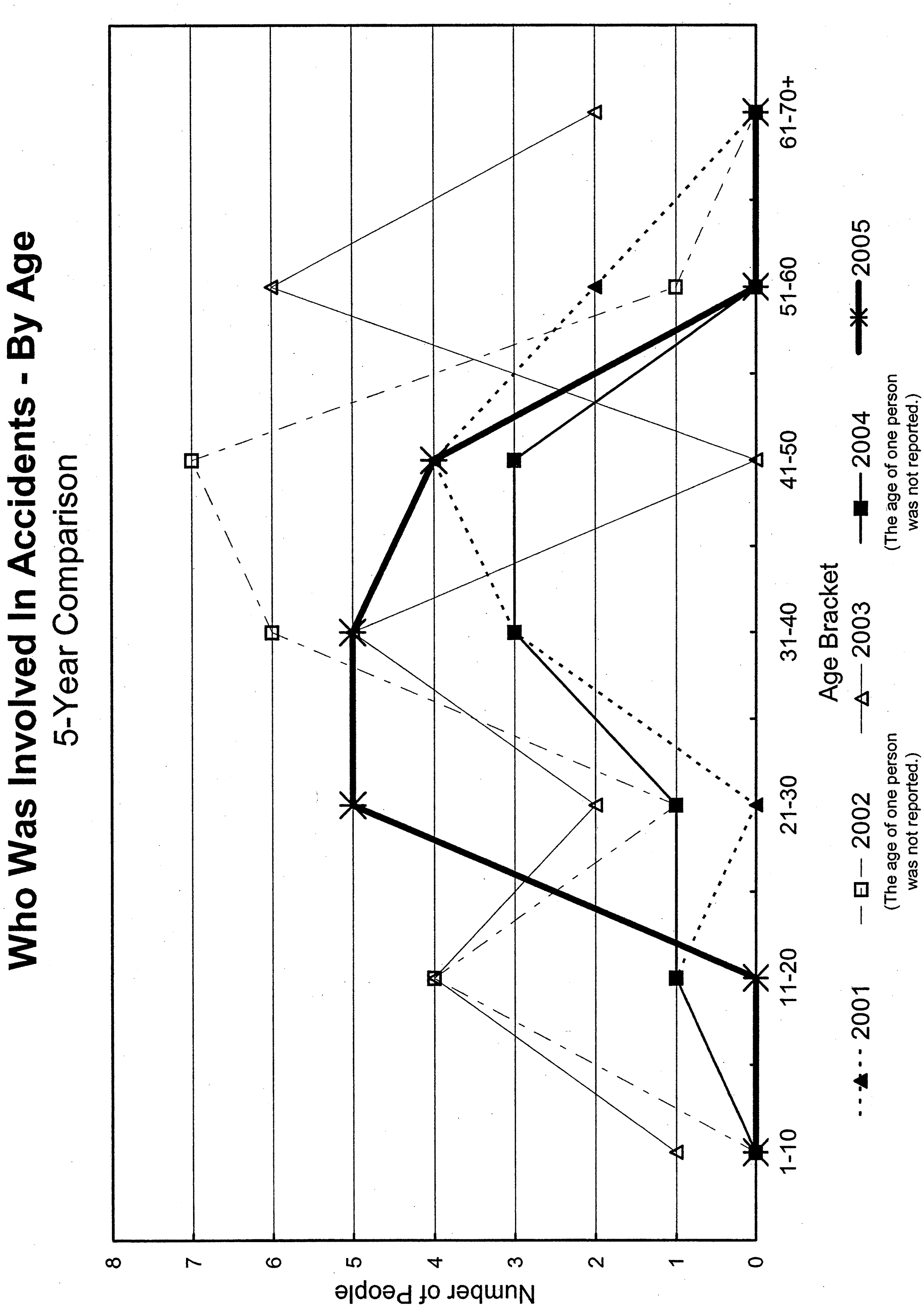
The next two charts indicate <u>Who Was Involved in Accidents</u>:

- **<u>By Activity Classification</u>** - This chart shows the trends over the last five years for the three categories.
- **<u>By Age</u>** - This five-year chart shows the typical historical pattern where most of the incidents involve men in their 20s, 30s, and 40s. The pattern for 2001 and 2002 was somewhat different, in that injuries involving young men in the 21-30 year old category were rare. The number of 2002 accidents to 11-20 year olds was very high due to a single incident where three young men were injured in a boating accident. 2003 has two unusual facts, with the 40s category at 0 and the 50s category very high at six injuries. 2004 and 2005 return to a more typical pattern.



Who Was Involved In Accidents - 5 Year History




Who Was Involved In Accidents - By Age
5-Year Comparison
Number of People
0
1
2
3
4
5
6
7
8
1-10
11-20
21-30
31-40
41-50
51-60
61-70+
Age Bracket
2001
2002
(The age of one person was not reported.)
2003
2004
(The age of one person was not reported.)
2005

The next four charts track 20 years of incidents related to certain equipment or activities.

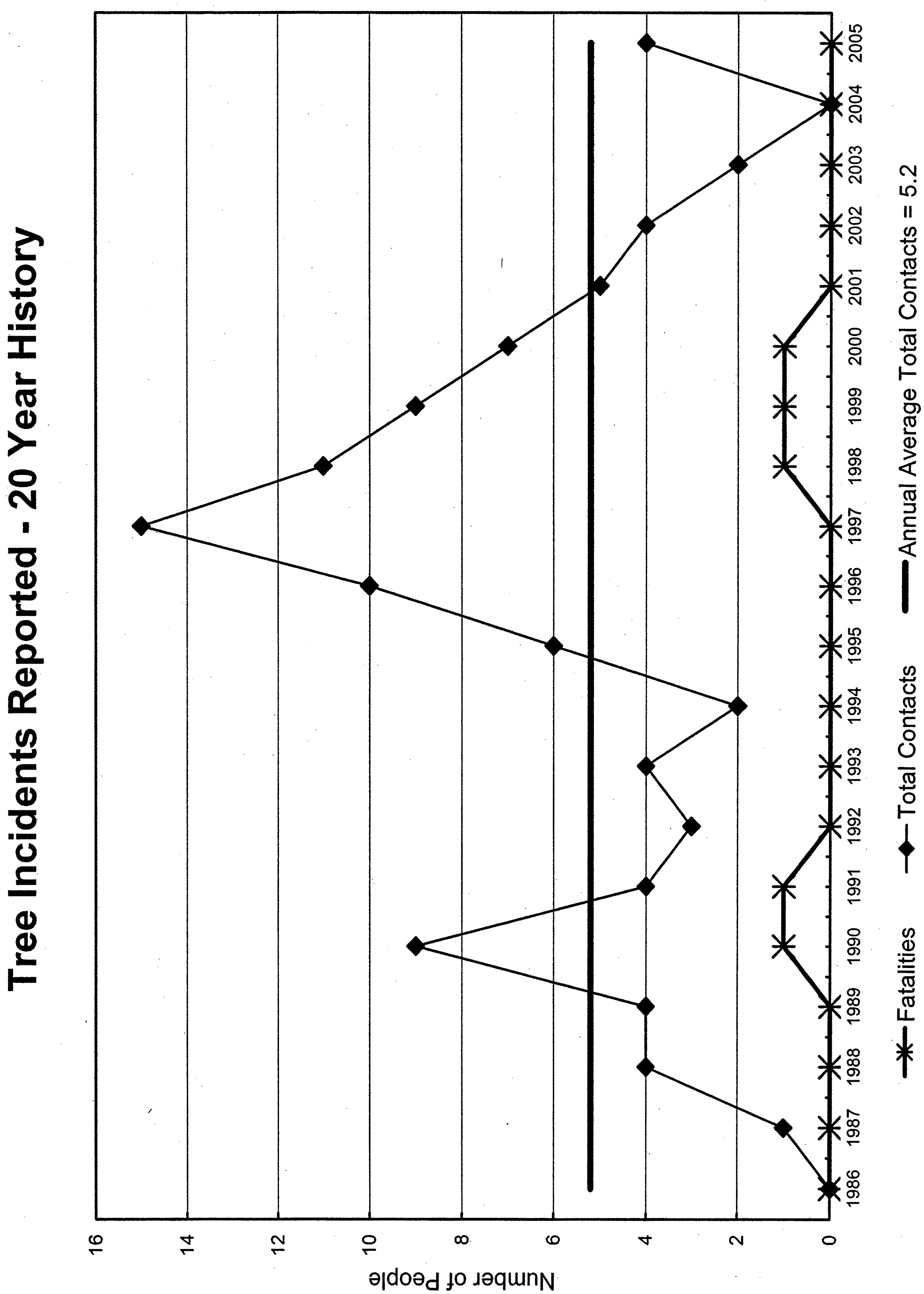
- **Tree-Related** – This category is, on average, where most people are injured. There has been an average of 5.2 tree-related contacts per year over the last twenty years. Many of these contacts involved homeowners trimming or falling trees in their yards. The majority of the remaining contacts were non-utility tree trimmers (landscapers) and loggers. If utility customers are going to get injured with high voltage lines, the chances are very high that it will be connected to a tree in their yard. The 2003 total of two injuries in this category is quite low. 2004 matches the astounding 1986 total of zero (0) accidents in this category.
  Unfortunately, four (4) men were injured doing this activity on their property in 2005.

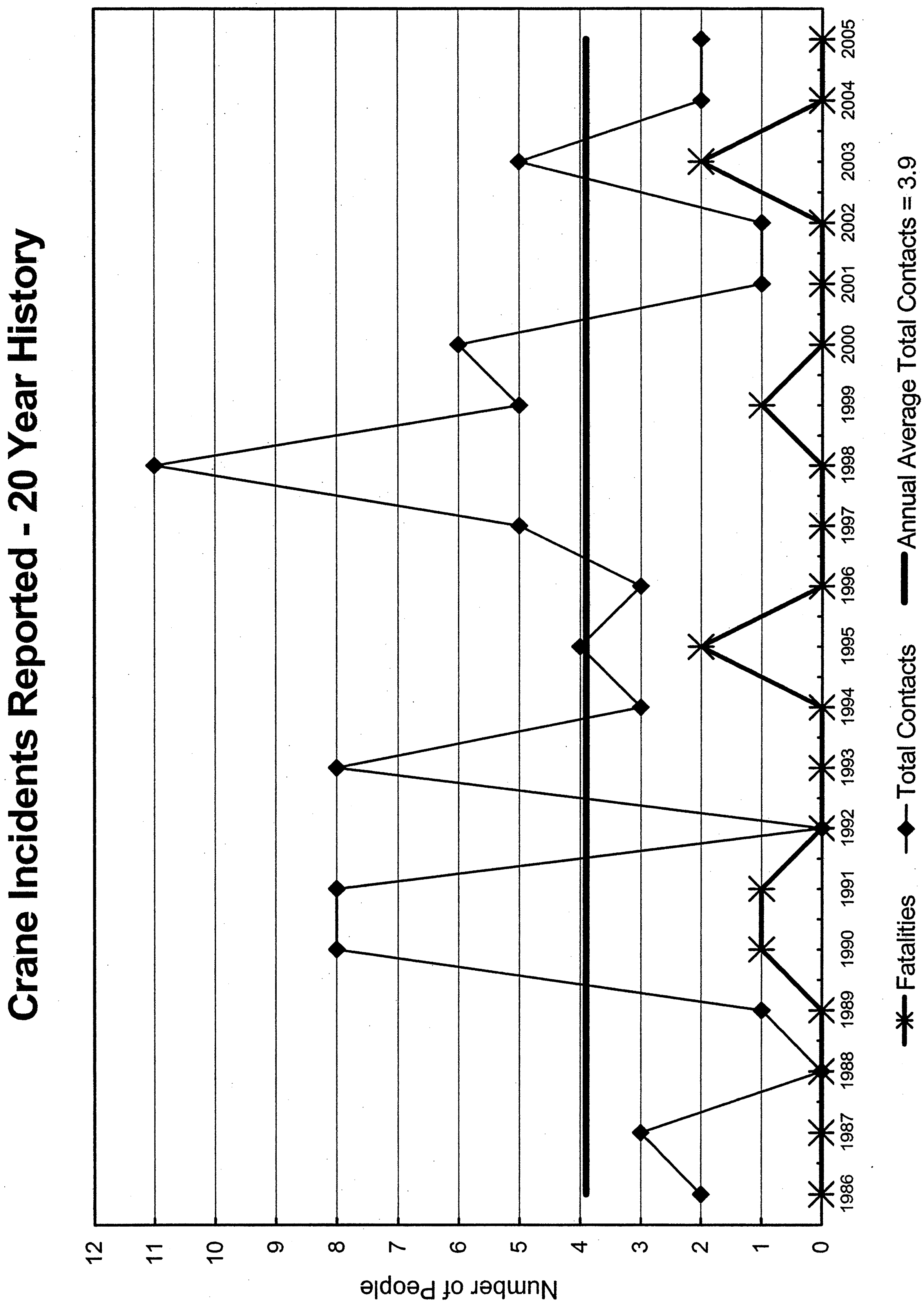
- **Crane-Related** - Crane contact has been a continuing source of concern needing special attention by the electric utilities and Oregon OSHA. Over this 20-year period, there has been an average of 3.9 people injured each year. Below are some conclusions taken from recent crane incidents.

  - Crane contacts have been the most likely incident type to result in multiple victims.
  - Line visibility is not a problem in most cases.
  - Most operators know of the line's presence.
  - The types of "crane" involved in line contacts are highly varied.
  - Operator experience and training is highly varied.
  - Moving cranes in the "up" position is dangerous.
  - Cement pumper incidents are becoming more frequent (two in 1999, another in 2001, and one in 2005).

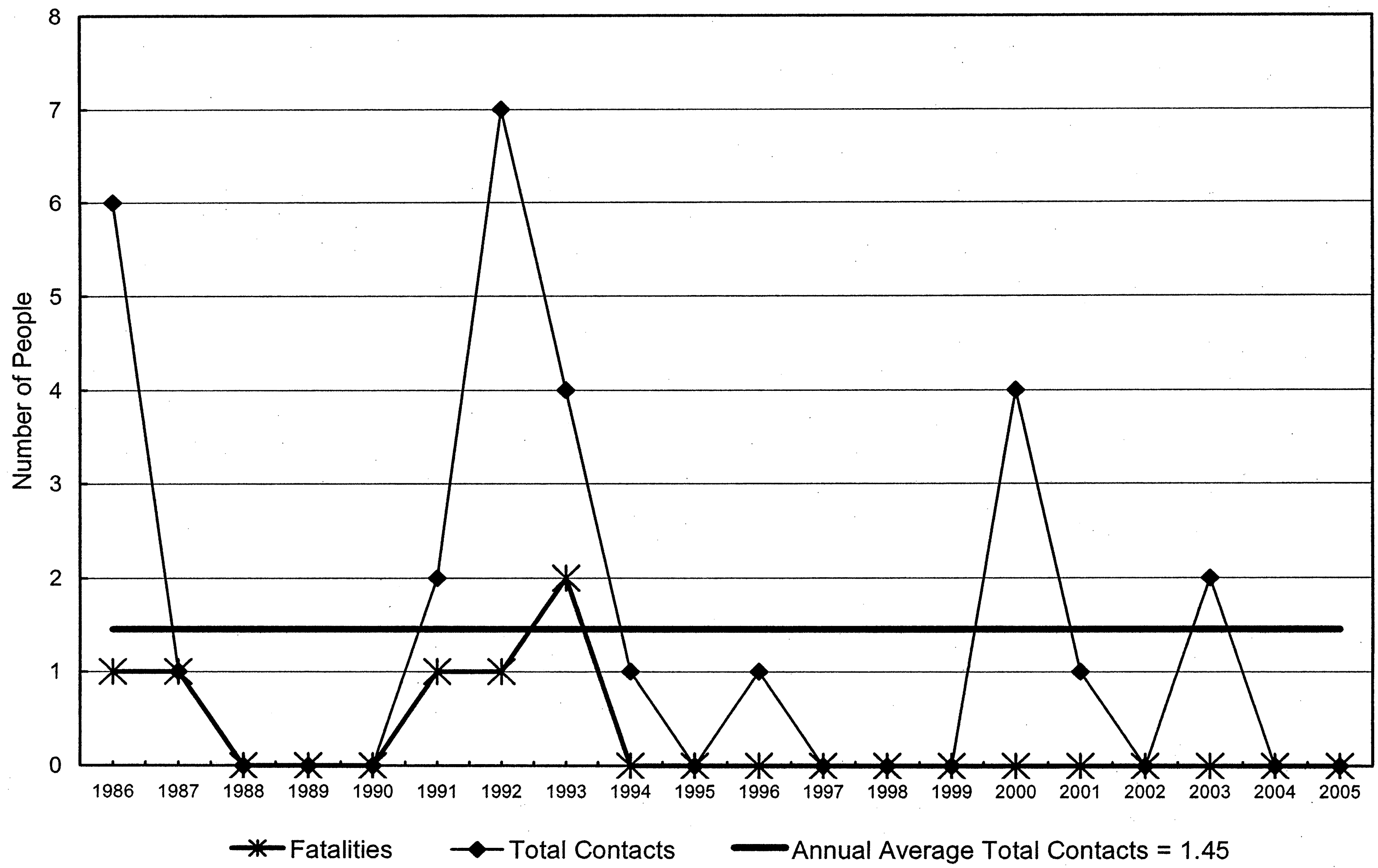
- **Irrigation Pipe-Related** - These incidents usually occur when farm workers raise pipes vertically to clear animals or debris. When a power line is above them, there are disastrous results. Constant utility education during certain times of year can help raise awareness and prevent accidents. Radio announcements seem to work well. Our investigations do reveal that even with education and awareness it is easy for people to just forget about the presence of overhead lines. Public service announcements on Spanish-speaking radio stations may be helpful. There were no accidents of this type in 2004 and 2005.

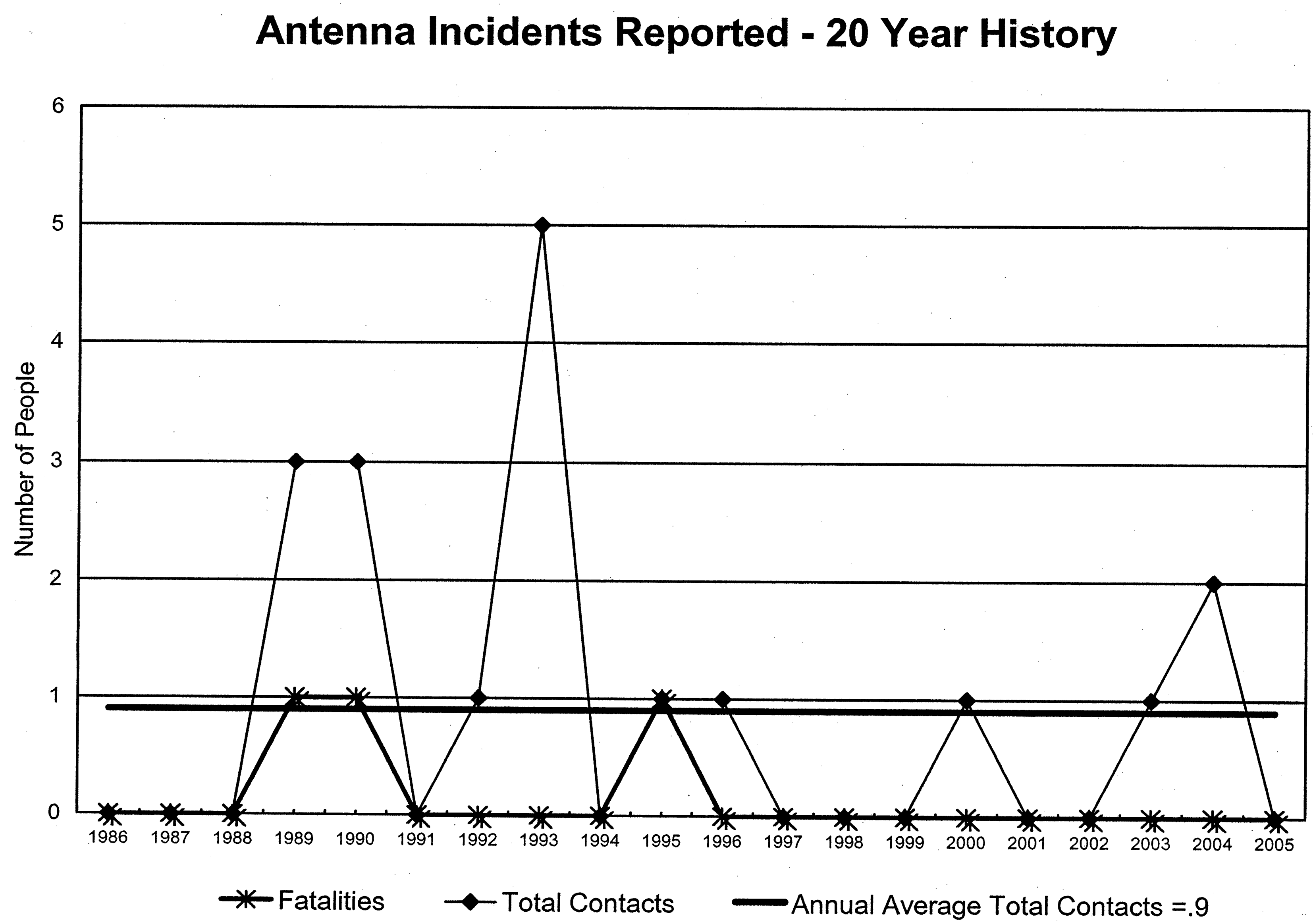
- **Antenna-Related** - Antenna contact is another area of concern that usually involves members of the public installing or maintaining equipment near homes. A father and his son were both injured in 2004 when the antenna they were installing on a roof fell into a high voltage distribution line. There were no antenna related accidents reported in 2005.


Tree Incidents Reported - 20 Year History
Number of People
0
2
4
6
8
10
12
14
16
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Fatalities
Total Contacts
Annual Average Total Contacts = 5.2


Crane Incidents Reported - 20 Year History
Number of People
0
1
2
3
4
5
6
7
8
9
10
11
12
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Fatalities
Total Contacts
Annual Average Total Contacts = 3.9

Irrigation Pipe Incidents Reported - 20 Year History




Antenna Incidents Reported - 20 Year History
Number of People
0
1
2
3
4
5
6
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
Fatalities
Total Contacts
Annual Average Total Contacts =.9

Year 2005

Breakdown by Activity Involved

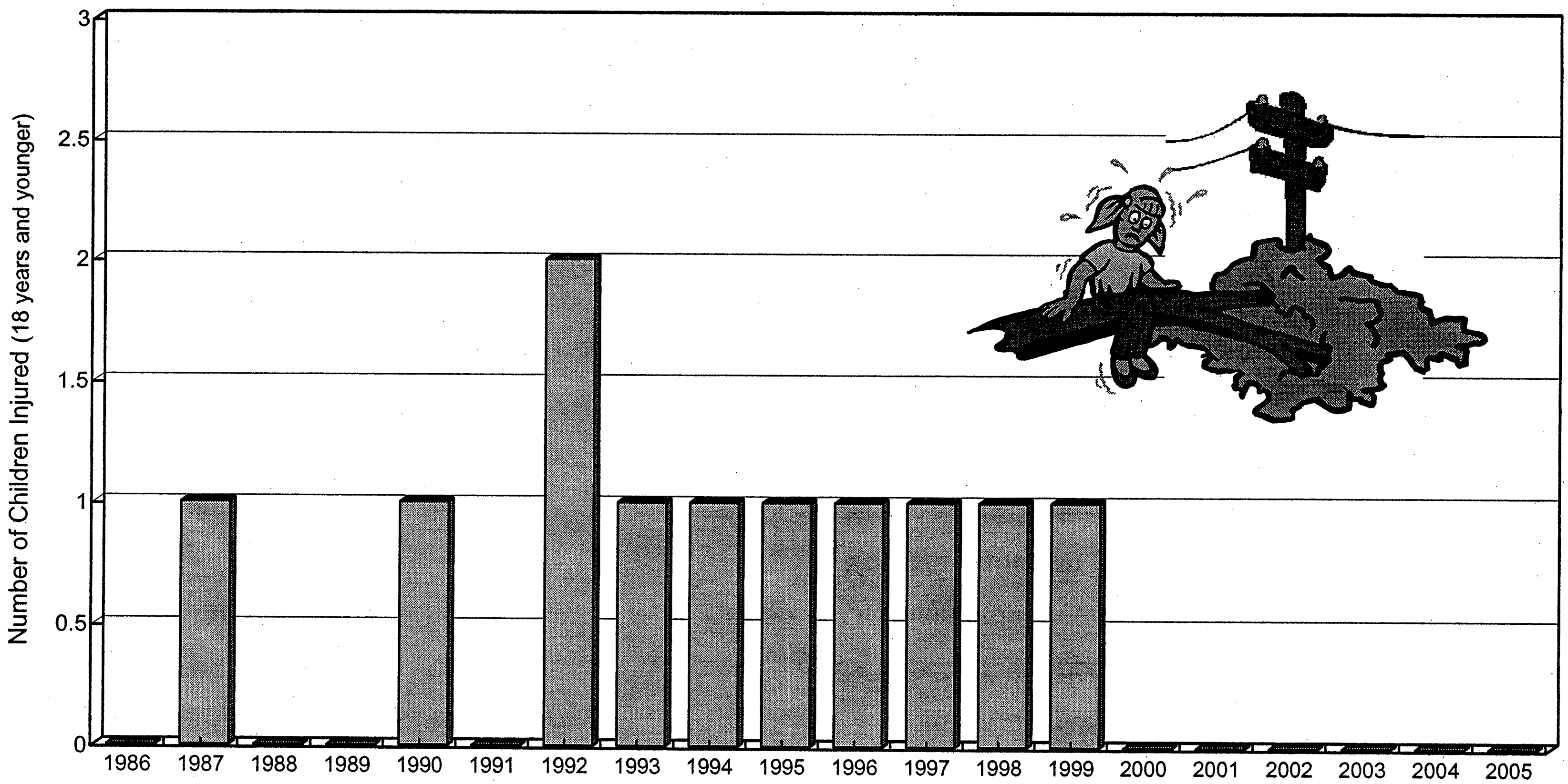
(By Person Injured)

Note: Some incidents fit into multiple categories.

- **Tree Trimming/Falling or Other Contact** 4
- **Excavation/Dig-ins/Underground bore** 3
- **Construction/Maintenance (all types)** 13
- **Irrigation Pipe** 0
- **Crane/Lift/Digger booms**
  - Lift 1
  - Cement pumper 1
  - Construction Crane into 115 KV 1
- **Ladder access**
  - Painter (ladder into line) 1
  - Sheet metal worker (gutter into line) 1
- **Line/Utility Related Work**
  - Overhead line work (electric) 1
  - Underground work 2
- **Direct Contact**
  - Line worker contacts (underground system) 1
  - Wire down on car / hit pole 1
  - Underground cable sawed into (plumber) 1
  - Underground cable (knife / electrician) 1
- **Vehicle collision (car hit pole)** 1
- **Homeowner (friends – contractor)**
  - Sheet metal worker (gutter into line/from ladder) 1
  - Electrician (in ditch) 1
  - Tree related 4
  - Plumber (in ditch) 1
  - Cement pumper 1
  - Painter (ladder into line) 1

Children in Trees - 20 Years

High Voltage Line Contacts in Oregon



Average Injury over 20-year period is about one every other year or .55 per year.

This last chart, <u>Children in Trees</u>, reflects some serious statistics for an activity that concerns us all. Although there were no injuries in this category in the last six years, we cannot afford to become complacent. This is an important safety issue. Staff believes that consistently better tree-to-line clearances being maintained across the state are directly contributing to these excellent results. Remember the years 1980 through 1983 when there were 12 children injured this way.

Recommendations to Electric Utilities by the OPUC Safety Staff

1. Continue the effective general safety education programs now in place. These efforts are preventing accidents. Ongoing programs for schools are particularly encouraged. All grade school students in Oregon should receive power line safety education at least twice during these years. Some excellent bill stuffers have been developed and we recommend their use for educating customers about common hazards. Specifically timed safety messages on radio and television are valuable to warn the public about downed lines and other hazards.

2. Focus educational programs to:

   a. Target construction workers where construction is anticipated. A special emphasis should be placed on work using crane or lift equipment. Crane related accidents have been very high when construction levels are up. Educate about dig-in hazards and one-call notification.

   b. Warn homeowners about electrical hazards related to trees. This is a key area needing emphasis to every customer.

   c. Continue education for agricultural workers. PUC staff specifically recommends broadcasting messages on Spanish language-speaking radio stations. Irrigation pipe accident prevention should particularly be emphasized. Stacking or laying out pipe under power lines should be discouraged (per OSHA rules). This has been a significant cause of serious injuries over the years.

3. Emphasize utility worker safety programs to reduce the number of contact incidents. A significant number have been experienced in the last 13 years (total 65). Consider the expanded use of rubber gloves in any primary area, overhead and underground, energized or not. Trends indicate that accidents related to underground systems are on the rise.

4. Notification of utilities should be encouraged prior to all work or activities, which will occur near both overhead and underground lines. An overhead notification system coupled with the statewide underground one-call system is recommended.

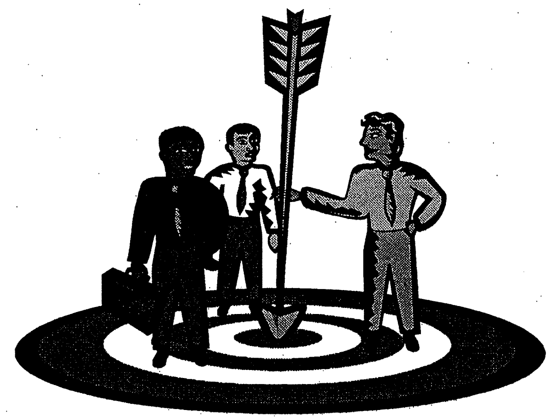
5. Maintain a National Electrical Safety Code compliant system to provide a consistently safe environment for electrical and communication workers.

Each electrical utility should consider these recommendations with the perspective of knowing your local conditions and activities, priorities, and potential hazards. Our hope is that this information will help you develop an effective accident prevention program.

Target

Your Education Efforts

Preventing accidents requires action!



- Use programs that have been successful in the past. Be creative in presenting information in attention getting ways.
- Try new ideas. Target problem areas. (Customers trimming their trees, or doing other homeowner maintenance, cranes, work sites, and dig-ins.)
- Reward creative new ideas and those who spot potential problem areas.
- Reward safe workers, especially those who consistently encourage safe practices for their crews.
- Give all employees the chance to know safety basics and be part of the accident prevention team.
- Electrical safety training should be a part of every grade school child's education at least twice.
- Consider using safety related bill stuffers regularly. Caution customers about tree related hazards. Homeowner maintenance resulted in a large number of high voltage contact accidents in 2005.
- Encourage and participate in at least one (per year) utility worker safety day (or half day) with all operators who share the overhead and underground rights of way with you.

**Public Safety Education is an essential responsibility of the electric utility industry.
Worker Safety Training and Supervision is required for all utility operators.**

AR 506

STAFF EXHIBIT 11

Oregon

John A. Kitzhaber, M.D., Governor

Public Utility Commission
550 Capitol Street NE
Salem, OR 97310-1380
(503) 373-7394

January 22, 1999

PEGGY FOWLER
PORTLAND GENERAL ELECTRIC
121 SW SALMON ST
PORTLAND OR 97204

I am writing in response to Dave Van Bossuyt's letter to Bob Sipler, dated January 5, 1999. The letter documents tree trimming stipulations and strategies by Portland General Electric to ensure ongoing compliance with the National Electrical Safety Code (NESC) and OPUC's tree clearance policy.

I support PGE in its efforts to develop long-range solutions to tree clearance issues. I further commend PGE's willingness to join with PacifiCorp in creating an ongoing Statewide Consortium to focus on powerline tree clearance standards, tree trimming crew stability, and successful program methods.

The Commissioners were individually made aware of the circumstances surrounding this agreement and OPUC Safety Report #E98-26. The report references evidence of extensive and serious probable violations of the NESC and OPUC's tree clearance policy.

Although, the Commissioners individually have not taken exception in allowing OPUC staff to pursue this agreement, be advised that PGE should not interpret this action as a lessening of our commitment to the standards stipulated in the Service Quality Measures in OPUC Order #97-196 and in the agency's tree clearance policy.

Ron Eachus

Ron Eachus
Chairman
(503) 378-6611
Fax: (503) 378-5505

CC: Commissioner Roger Hamilton
Commissioner Joan Smith

Portland General Electric Company
4245 Kale Street N.E. • Salem, Oregon 97305
1-800-544-1793

January 5, 1999

Mr. Bob Sipler
Utility Safety & Reliability
Public Utility Commission
550 Capitol Street
Salem, OR 97310-1380

Dear Mr. Sipler:

Attached is the signed copy of the details of our agreement on PGE's tree trimming program.

Dave Van Bossuyt
General Manager

Enclosure (1)

In response to PUC Report E98-26, and as a result of discussions with PUC staff, PGE agrees to the following:

1. Inclusion of solutions offered in PGE's response letter dated November 17, 1998. (Two year trimming cycle in urban areas, etc.)

2. On or before July 1, 1999, all readily climbable trees on PGE's system will have been identified and trimmed to achieve the necessary five (5) foot clearance. Further, in forested areas or where there exists a significant degree of fire danger, a minimum clearance of three (3) feet shall have been achieved.

3. During the period of time necessary (on or before July 1, 2000) to transition to a two year trimming cycle, PGE will endeavor to ensure that there will be a minimum of vegetation intrusion into the clearance areas defined in Section 2b of the OPUC policy.

4. On or before July 1, 2000, PGE will achieve and maintain full compliance with the OPUC Policy (Attached and labeled as Attachment A) on Tree To Power Line Clearances, as interpreted by PUC staff.

5. PGE acknowledges that "tickling", "brushing" contacts, brown leaves, desiccation, or any other descriptions, or results of, direct or arcing contact with primary conductors is interpreted by OPUC staff as interference. Such interference is unacceptable and not in compliance with the minimum clearances listed in the OPUC tree trimming policy.

6. PGE agrees to submit, for review by the PUC staff, a ten (10) year operating plan related to its tree trimming program. This plan, due no later than March 1, 1999, will incorporate those elements listed in Attachment B.

7. PGE agrees to report to PUC staff, on a semi-annual basis (every six months), all aspects of its tree trimming program. Attachment C, which details reporting elements, accompanies this document and is deemed to be a part of the agreement.

8. PGE agrees to work cooperatively with representatives of PacifiCorp in developing and implementing a statewide consortium of electric utilities, focusing on tree clearance issues, as follows:
   - Development and stabilization of qualified and adequate tree trimming resources for Oregon and the region
   - Jointly developing and making recommendations for powerline tree clearance standards and practices for the region that can be developed into PUC state law and policy, should statewide levels of non-compliance indicate that necessity. These standards, once developed, might also be considered for adoption as ANSI national standards.

- Annual vegetation growth rate histories and future predictions.
- Prevention of and inspection for readily climbable trees in close proximity to powerlines.
- Urban forestry efforts that encourage the "Right tree in the Right Place."
- Forest fire prevention and cooperation with national and state forestry management agencies.
- Prevention of outages caused by off the public rights-of-way trees.
- Development of "Call-Before-You-Trim" statewide program and promotion of overhead one-call.
- Public safety education. (Ideas, resources, etc.)
- Tree-affected storm damage prevention and restoration.
- Utility tree clearance benchmarking.
- New proven utility arborculture techniques.
- New tools and equipment.
- Public relations.

9. Upon successful development of the consortium referred to in the previous item, PGE and PacifiCorp agree to alternately host and chair annual meetings, the first of which shall occur no later than November 1, 1999. Both utilities should recognize that a valuable resource is available in FEMA Report 1107-DR-OR. PGE must notify OPUC staff, within thirty (30) days of signature of this document, of which utility will take responsibility for the first annual meeting. Should PacifiCorp not agree to participate, PUC staff will entertain other proposals that will achieve establishment of the consortium.

Joe McArthur 1/5/99
Joe McArthur Date
On behalf of PGE

ATTACHMENT A

Oregon Public Utility Commission
Staff Policy

Tree To Power Line Clearances

PURPOSE

The purpose of this policy is to modify and define the tree trimming rules of ANSI C2, National Electrical Safety Code (NESC) as interpreted by the administrative authority (Reference--NESC Rules 012, 013, and 218). This policy is to set forth the specifications and guidelines relating to tree trimming, tree removal, and line clearance to provide for reasonable service continuity, safety to the public, and to guard against forest fire damage caused by supply conductors.

POLICY

Trees which may interfere or do interfere with supply conductors should be trimmed or removed.

A. Specifications and guidelines for line clearances.

1. The necessary clearance of supply lines from trees is determined by:

   a. Voltage, location, and importance of individual line.

   b. The height of the poles and line.

   c. The growth habit and final appearance of the trees.

   d. Combined movement of trees and conductors under adverse weather conditions.

   e. Sag of conductors at elevated temperatures.

2. Concept:

   a. Transmission lines should have a minimum clearance of ten feet in all directions.

   b. Primary distribution lines.

      There should be a minimum 5-foot clearance between an energized high voltage distribution conductor and any part of a tree. This clearance may be reduced to three feet if the tree is not readily climbable (having sufficient handholds and footholds to permit an average person to climb easily without using a ladder or other special equipment).

Trees should be trimmed to the extent that this designated minimum clearance area will be kept free of new tree growth until the next scheduled trimming cycle. If the trimming cycle is other than three years, as may be needed for fast-growing tree species or where limited trimming is permitted by the tree owner, appropriate records need to be maintained to insure timely trimming is accomplished.

Intrusion of limited small branches and new tree growth into this minimum clearance area can be tolerated so long as it does not contribute to a safety hazard to a person climbing the tree or cause interference with the conductors.

c. Secondary and/or service conductors (600 volts and below) should have at least 1-foot clearance. While extensive tree trimming or tree removal relating to these services is not expected, proper consideration must be given to possible conductor damage and service outages caused by trees, and appropriate measures taken.

B. Tree removal. Whenever justified, tree removal should be encouraged. Trees should be removed under the following conditions:

1. Trees located in school yards, playgrounds, parks, backlot construction areas, or other areas and which children may climb easily and contact overhead conductors.

2. Trees that have been topped under low-level primary and transmission circuits with no chance for a reasonable, natural development.

3. Trees that are unsightly because of excessive trimming and cannot be economically retrimmed.

4. Trees in rural areas along county roads and state highways which would eventually reach a primary or transmission line.

5. Fast-growing tree species located in suburban and urban areas, near homes or in landscaped areas which will eventually grow into transmission or distribution lines.

6. Trees, both live and dead, which are leaning toward the line and which would strike the line when falling.

(Issued before 1983; revised Jan. 1987)

I:Safety:Electric:Policies:Trees.doc

ATTACHMENT B

Operation and Maintenance Plan

Written policies, standards, schedules, and procedures for vegetation management programs for electrical utilities and operators.

A. **Public Education**
- General Public Education
- Non-utility tree trimmer safety education for working near power lines
- Overhead One-call (i.e. "Call before you trim", "call before you log")
- Third party damage prevention (i.e., danger trees, etc.)
- Public relations
- Special target areas unique to company

B. **Program Design, Plans, Policies, Standards and Schedules**
- Management Goals and Focus
- Cyclic Trimming
- Hot Spot Trimming
- Customer Call Trimming
- New Contruction
- Focus areas (i.e., end-of-cycle clearances, readily climbable trees, forested and other areas with fire concerns, fast growing trees, etc.)

C. **Hazard and Violation Response, Feeder Patrol, Prioritization and Correction**

D. **Program Implementation**
- OPUC tree clearance policy compliance (Getting results)
- Quality assurance
- Management checking and follow-up
- Changes to ensure Program effectiveness

E. **Safety Inspection and Defect Correction**
- Safety Inspection Program
- Detailed Inspection Program

F. **Continuing Surveillance**

G. **Investigations of Failures**

H. **Resources**
- Expenditures (5-year history)
- Budgets (5-year planned)
- Manpower qualifications
- Manpower availability (5-year planning)

Attachment B,
Page two

I. Other Program Elements

- Annual and routine reporting
- Public Safety Education (Target areas, budgets, expenditures,)
- "Readily climbable trees" Prevention
- Forest fire prevention
- Danger trees off R-O-W
- Historical tree growth rates and predictions
- Urban forestry (i.e., Powerline Perfect Trees)
- Utility benchmarking
- Arborculture practices
- Tree removal and cycle busters

ATTACHMENT C

Tree Program Reporting

Semi-annual reporting: January through June information is due by September 30 and July through December due on March 31, for 10 years, with first report submitted on March 1, 1999.

Reports shall contain:

A. Summary Information for each distribution circuit or grid:
   1. Last cycle trim date and next scheduled trim date (by year and quarter).
   2. Current condition related to compliance with OPUC tree clearance policy (at end of reporting period)
   3. Map showing cyclic work progress/schedules by district/division.

B. Work accomplished, itemized by district/division and by statewide. Show transmission statewide separately.
   1. Total existing line miles in any configuration (3-phase, 2-phase, 1-phase, etc.)
   2. # Line miles worked
   3. # Miles "on" and "behind" schedule
   4. Percent of line miles "on" and "behind" schedule

C. Budget Plan and Actual Expenditures for statewide tree trimming program. Show transmission separately.
   1. Budgeted amount for current year including plan for five future years
   2. Actual costs (YTD) including five year historic trending
   3. Actual costs versus budget (YTD)
   4. Average # tree crews on property (YTD)

D. Tree-related Safety Issues*
   1. # Public electrical contacts involving trees**
   2. # Powerline caused fires**
   3. # Readily climbable trees reported
   4. # Readily climbable trees corrected

E. Service Reliability*
   1. # Non-preventable tree related outages
   2. # Preventable tree related outages
   3. # Total tree related outages

F. Tree Crew Productivity and Benchmarking
   1. Average, high and low cost per line mile in 2 year cycle areas
   2. Average, high and low cost per line mile in 3 year cycle areas

G. Scheduled Work versus Non-scheduled work (i.e., customer calls, storm work, unscheduled hotspotting, PUC violations, etc.)
   1. Distribution non-scheduled work compared to total annual costs
   2. Transmission non-scheduled work compared to total annual costs

Notes: (*) YTD information (**) Itemize incidents on a separate sheet with submitted report.

Oregon
John A. Kitzhaber, M.D., Governor

Public Utility Commission
550 Capitol Street NE
Salem, OR 97310-1380
(503) 373-7394

January 22, 1999

WILLIAM EAQUINTO
PACIFIC POWER
525 WILCO RD.
STAYTON, OR 97383

Enclosed is a copy of the signed Agreement between PacifiCorp and Oregon PUC staff which documents tree trimming stipulations and strategies by PacifiCorp to ensure ongoing compliance with the National Electrical Safety Code (NESC) and OPUC's tree clearance policy.

It is important for PacifiCorp to develop long-range solutions to tree clearance issues. I commend PacifiCorp's willingness to join with Portland General Electric in creating an ongoing Statewide Consortium to focus on powerline tree clearance standards, tree trimming crew stability, and successful program methods.

The Commissioners were individually made aware of the circumstances surrounding this agreement and OPUC Safety Report #E98-19. Specifically, the report references evidence of extensive and serious probable violations of the NESC and OPUC's tree clearance policy.

Although, the Commissioners individually have not taken exception in allowing OPUC staff to pursue this agreement, be advised that PacifiCorp should not interpret this action as a lessening of our commitment to the standards stipulated in the Service Quality Measures in OPUC Order #98-191 and in the agency's tree clearance policy. Neither should PacifiCorp doubt our willingness to impose penalties or other remedies should PacifiCorp not adhere to the terms of this agreement.

Ron Eachus

Ron Eachus
Chairman
(503) 378-6611
Fax: (503) 378-5505

CC: Commissioner Roger Hamilton
Commissioner Joan Smith

Attachment

AGREEMENT

The parties to this Agreement, PacifiCorp and Oregon PUC staff, as a result of discussions related to violations cited regarding PacifiCorp's tree trimming program, enter into this Agreement as an alternative to proceeding with the remedies stipulated in the Service Quality Measures (SQM) plan approved in Order No. 98-191. SQM plan remedies were formulated for instances of utility failure to adhere to the plan and include financial penalties for each instance deemed to be a Major Safety Violation (MSV)

The parties agree to the following terms:

1. On or before July 1, 1999, all readily climbable trees on PacifiCorp's Oregon system will have been identified and trimmed to achieve the necessary five (5) foot clearance. Further, in forested areas or where there exists a significant degree of fire danger, a minimum clearance of three (3) feet shall have been achieved.

2. During the period of time between July 1, 1999 and July 1, 2000, PacifiCorp will endeavor to ensure that there will be a minimum of vegetation intrusion into the clearance areas defined in Item #1 and addressed by Section 2b of the OPUC Staff Policy, Tree to Power Line Clearances, attached as Attachment A (OPUC Tree Clearance Policy).

3. On or before July 1, 2000, PacifiCorp will achieve and maintain full compliance with the OPUC Tree Clearance Policy.

4. "Ticklers", "brushing" contacts, brown leaves, or any other contact with primary conductors~~,~~ are interpreted by OPUC staff as interference. Such interference is unacceptable and not in compliance with the OPUC Tree Clearance Policy.

5. PacifiCorp will submit, for review by the PUC staff, a ten (10) year operating plan related to its tree-trimming program. This plan, due no later than March 1, 1999, will incorporate those elements listed in Attachment B.

6. PacifiCorp will regularly report to PUC staff on all aspects of its tree-trimming program, consistent with the provisions of Attachment C

7. PacifiCorp will work cooperatively with representatives of PGE in developing and implementing a statewide consortium of electric utilities, focusing on, but not limited to, the following tree trimming issues:

- Development and stabilization of qualified and adequate tree trimming resources for Oregon and the region.

- Development of powerline tree clearance standards and practices for the region that can be developed into PUC regulation/policy, should statewide levels of non-compliance indicate that necessity. These standards, once developed, might also be considered for adoption as ANSI national standards.

- Annual vegetation growth rate histories and future predictions.

- Prevention of and inspection for readily climbable trees in close proximity to powerlines.

- Urban forestry efforts that encourage the "Right tree in the Right Place."

- Forest fire prevention and cooperation with national and state forestry management agencies.

- Prevention of outages caused by off the public rights-of-way trees.

- Development of "Call-Before-You-Trim" statewide program and promotion of overhead one-call.

- Public safety education. (Ideas, resources, etc.)

- Tree-affected storm damage prevention and restoration.

- Utility tree clearance benchmarking.

- New proven utility arboculture techniques.

- New tools and equipment.

- Public relations.

8. Upon successful development of the consortium referred to in the previous item, PacifiCorp and PGE agree to alternately host and chair the annual meetings, the first of which shall occur no later than November 1, 1999. Both utilities should recognize that a valuable resource is available in FEMA Report 1107-DR-OR. PacifiCorp must notify OPUC staff, within thirty (30) days of signature of this

document, of which utility will take responsibility for the first annual meeting. Should PGE not agree to participate, PUC staff will entertain proposals from PacifiCorp that will achieve establishment of the consortium.

9. There will be no significant reduction of other maintenance programs related to the SQM, as a result of the conditions of this solution

10. Upon signature of this Agreement, further action on the notice of MSV currently under consideration by PUC staff will be deferred, pending PacifiCorp's compliance with the terms of this Agreement. On September 1, 2000, unless the OPUC determines that PacifiCorp has failed to comply with the terms of this Agreement, the MSV will be declared void and no further action will be taken by PUC staff.

11. Except as specified in Item # 10, this Agreement will continue in effect until the end of 2009.

This Agreement is entered into this ~~22~~ day of ~~December, 1998~~. January, 1999, WBW

PACIFICORP

By: Richard D Westerberg
Richard Westerberg
Title: Vice President

OPUC STAFF

By: William Warren
William Warren
Title: Director, Utility Program

ATTACHMENT A

Oregon Public Utility Commission
Staff Policy

Tree To Power Line Clearances

PURPOSE

The purpose of this policy is to modify and define the tree trimming rules of ANSI C2, National Electrical Safety Code (NESC) as interpreted by the administrative authority (Reference--NESC Rules 012, 013, and 218). This policy is to set forth the specifications and guidelines relating to tree trimming, tree removal, and line clearance to provide for reasonable service continuity, safety to the public, and to guard against forest fire damage caused by supply conductors.

POLICY

Trees which may interfere or do interfere with supply conductors should be trimmed or removed.

A. Specifications and guidelines for line clearances.

1. The necessary clearance of supply lines from trees is determined by:

   a. Voltage, location, and importance of individual line.

   b. The height of the poles and line.

   c. The growth habit and final appearance of the trees.

   d. Combined movement of trees and conductors under adverse weather conditions.

   e. Sag of conductors at elevated temperatures.

2. Concept:

   a. Transmission lines should have a minimum clearance of ten feet in all directions.

   b. Primary distribution lines.

      There should be a minimum 5-foot clearance between an energized high voltage distribution conductor and any part of a tree. This clearance may be reduced to three feet if the tree is not readily climbable (having sufficient handholds and footholds to permit an average person to climb easily without using a ladder or other special equipment).

Trees should be trimmed to the extent that this designated minimum clearance area will be kept free of new tree growth until the next scheduled trimming cycle. If the trimming cycle is other than three years, as may be needed for fast-growing tree species or where limited trimming is permitted by the tree owner, appropriate records need to be maintained to insure timely trimming is accomplished.

Intrusion of limited small branches and new tree growth into this minimum clearance area can be tolerated so long as it does not contribute to a safety hazard to a person climbing the tree or cause interference with the conductors.

c. Secondary and/or service conductors (600 volts and below) should have at least 1-foot clearance. While extensive tree trimming or tree removal relating to these services is not expected, proper consideration must be given to possible conductor damage and service outages caused by trees, and appropriate measures taken.

B. Tree removal. Whenever justified, tree removal should be encouraged. Trees should be removed under the following conditions:

1. Trees located in school yards, playgrounds, parks, backlot construction areas, or other areas and which children may climb easily and contact overhead conductors.

2. Trees that have been topped under low-level primary and transmission circuits with no chance for a reasonable, natural development.

3. Trees that are unsightly because of excessive trimming and cannot be economically retrimmed.

4. Trees in rural areas along county roads and state highways which would eventually reach a primary or transmission line.

5. Fast-growing tree species located in suburban and urban areas, near homes or in landscaped areas which will eventually grow into transmission or distribution lines.

6. Trees, both live and dead, which are leaning toward the line and which would strike the line when falling.

(Issued before 1983; revised Jan. 1987)

I:Safety:Electric:Policies:Trees.doc

ATTACHMENT B

Operation and Maintenance Plan

Written policies, standards, schedules, and procedures for vegetation management programs for electrical utilities and operators.

A. Public Education
- General Public Education
- Non-utility tree trimmer safety education for working near power lines
- Overhead One-call (i.e. "Call before you trim", "call before you log")
- Third party damage prevention (i.e., danger trees, etc.)
- Public relations
- Special target areas unique to company

B. Program Design, Plans, Policies, Standards and Schedules
- Management Goals and Focus
- Cyclic Trimming
- Hot Spot Trimming
- Customer Complaint Trimming
- New Contruction
- Focus areas (i.e., end-of-cycle clearances, readily climbable trees, forested and other areas with fire concerns, fast growing trees, etc.)

C. Hazard and Violation Response, Prioritization and Correction

D. Program Implementation
- OPUC tree clearance policy compliance (Getting results)
- Quality assurance
- Management checking and follow-up
- Changes to ensure Program effectiveness

E. Safety Inspection and Defect Correction
- Safety Inspection Program
- Detailed Inspection Program

F. Continuing Surveillance

G. Investigations of Failures

H. Resources
- Expenditures (5-year history)
- Budgets (5-year planned)
- Manpower qualifications
- Manpower availability (5-year planning)

Attachment B,
Page two

H. **Other Program Elements**

- Annual and routine reporting
- Public Safety Education (Target areas, budgets, expenditures,)
- "Readily climbable trees" Prevention
- Forest fire prevention
- Danger trees off R-O-W
- Historical tree growth rates and predictions
- Urban forestry (i.e., Powerline Perfect Trees)
- Utility benchmarking
- Arborculture practices
- Tree removal and cycle busters

ATTACHMENT C

Tree Program Reporting

Semi-annual reporting: January through June information is due by September 30 and July through December due on March 31, for 10 years, with first report submitted on March 1, 1999. For the term of this agreement, this method will fulfill the reporting requirement PUC Order 87-512 and the Letter of Understanding dated December 15, 1995.

Reports shall contain:

A. Summary Information for each distribution circuit or grid:
   1. Last cycle trim date and next scheduled trim date (by year and quarter).
   2. Current condition related to compliance with OPUC tree clearance policy (at end of reporting period)
   3. Map showing cyclic work progress/schedules by district/division.

B. Work accomplished, itemized by district/division and by statewide. <u>Show transmission statewide separately.</u>
   1. Total existing line miles in any configuration (3-phase, 2-phase, 1-phase, etc.)
   2. # Line miles worked
   3. # Miles "on" and "behind" schedule
   4. Percent of line miles "on" and "behind" schedule

C. Budget Plan and Actual Expenditures for statewide tree trimming program. <u>Show figures for transmission separately.</u>
   1. Budgeted amount for current year including plan for five future years
   2. Actual costs (YTD) including five year historic trending
   3. Actual costs versus budget (YTD)
   4. Average # tree crews on property (YTD)

D. Tree-related Safety Issues*
   1. # Public electrical contacts involving trees**
   2. # Powerline caused fires**
   3. # Readily climbable trees reported
   4. # Readily climbable trees corrected

E. Service Reliability*
   1. # Non-preventable tree related outages
   2. # Preventable tree related outages
   3. # Total tree related outages

F. Tree Crew Productivity and Benchmarking
   1. Average Cost per tree worked
   2. Average Cost per tree trimmed
   3. Average Cost per tree removed
   4. Percent trees trimmed versus trees removed

G. Scheduled Work versus Non-scheduled work (i.e., customer complaints, storm work, unscheduled hotspotting, PUC violations, etc.)
   1. Distribution non-scheduled work compared to total annual costs
   2. Transmission non-scheduled work compared to total annual costs

Notes: (*) YTD information (**) Itemize incidents on a separate sheet with submitted report.

AR 506

STAFF EXHIBIT 12

Oregon Public Utility Commission Policy

Safety Provisions for Joint-Use of Poles

The Public Utility Commission has adopted this policy as a reasonable and prudent practice to ensure safety of Oregon's overhead rights-of-way.

1. Purpose

The purpose of this policy is to ensure the safe and efficient use of overhead line rights-of-way. This policy establishes provisions necessary to ensure compliance with the National Electrical Safety Code (NESC) as required by ORS 757.035, OAR 860-024-0010 and OAR 860-034-0430 as interpreted by the administrative authority. Refer to applicable NESC rules, with a focus on rules 012, 013, 213, 214, 217, 220, 221, and 222.

2. Scope

This policy applies to all electric and telecommunication system owners or operators (including utilities), and other authorized entities that attach lines, equipment, or devices to joint-use poles.

3. Definitions (For other definitions, see the NESC Section 2, Definitions)

Attachment Project. Any addition, modification or removal of any electric supply line, signal line, device, apparatus, equipment, or structural member that materially changes the clearance, mechanical, structural, or electrical characteristics of the joint-pole installation. Maintenance replacements that do not modify the installation or affect other joint-pole users are intended to be exempted.

Joint-pole users. All utilities or entities with line, equipment, or device attachment(s) on a specified pole or joint-pole installation, including the pole owner and the electric joint-user.

Modifying entity. Any utility or entity planning or carrying out an attachment project to a pole installation(s).

4. Notification and Coordination

a. The modifying entity shall give prior written notification to the pole owner for each attachment project. The modifying entity shall receive written preauthorization from the pole owner before attaching. The notification shall be given in a timely manner to allow for ample engineering and coordination by affected joint-pole users. Sufficient coordination including submittal of project plans and exchange of information shall take place between joint-pole users so that the attachment does not create a NESC violation or conflict. Written notifications, authorizations, project plans and certifications shall be transmitted by paper or by electronic means using computers, fax, e-mail, Internet, etc.

b. Exception. Where NESC compliance can be assured, the modifying entity may be exempted from any of the written documentation provisions associated with prenotification, project plans, project certification or pole owner authorization at the pole-owner's discretion. This should only apply if the modifying entity has a written agreement with the pole owner that such submittals are unnecessary under specified conditions and limitations.

5. Engineering and Project Planning

Each attachment project shall involve sufficient planning by the modifying entity to ensure NESC compliance during construction and upon completion. The project plans shall include sufficient design drawings and specifications so that qualified personnel can safely make the attachments in compliance with the NESC and joint-pole agreements. Except as noted in paragraph 4.b., written project plans shall be submitted to the pole owner prior to commencing the attachment project.

6. Qualified Personnel

Joint-pole users shall only use trained qualified persons to work on joint-pole installations. Qualified persons shall be knowledgeable in applicable NESC rules and must be able to demonstrate competence as required by NESC rule 420.A.1. They shall also be trained to recognize and prevent NESC violations and conflicts, and to keep safe working clearances from energized lines and equipment.

7. Inspection, Maintenance and Compliance Responsibilities
(The below applies to both new and existing joint-pole installations.)

a. Each joint-pole user shall take appropriate means to ensure the safety of its lines and devices.

b. Each joint-pole user shall promptly respond to pole-owner notifications related to, but not limited to, maintenance, relocation, rearrangement, violations, or abandonment of joint-pole installations.

c. Except as noted in 4.b. above, upon completion of an attachment project, the modifying entity shall give written certification to the pole owner that the attachment project is complete and complies with the NESC.

d. Each joint-pole user shall conduct sufficient inspections and prompt repairs to ensure ongoing NESC compliance of its lines and facilities. In cases where discovered safety violations cannot be corrected safely or in a timely manner, the pole owner shall be notified promptly of the conditions.
(Also, refer to NESC rule 214 and PUC Staff policy on "Requirements for Line Inspection by Utility Operators.)

e. Each joint-pole user shall ensure that its employees and employed contractors are following project plans, joint-use agreements, standard practices, and NESC rules.

f. Joint-pole users that fail to promptly correct their NESC violations are responsible for costs including inspection, design, coordination, repair, etc. that the pole owner incurs in correcting such violations and in ensuring joint-use safety. Refer to OAR 860-022-0055(8).

8. Pole Owner Responsibilities

a. The pole owner must promptly respond to all notifications so that attachment projects and safety violation corrections are not unduly delayed. The pole owner may deny access if the attachment project will result in safety, reliability, and generally accepted engineering standards not being met.

b. Each pole owner should have written standard practices that address construction standards and communication protocols to be followed by joint-pole users. The standards should specify any obligations that exceed NESC regulations. These standards should also address communication methods and contacts for notifications, project plans, authorizations, and compliance certifications. These standards should be made readily available to requesting entities.

9. Electric Joint-Pole User Responsibilities

Special coordination is required for joint-use poles supporting high voltage lines (over 600 volts) where the poles are not owned by the electric joint-pole user. In such cases, the electric joint-pole user shall have agreements with the pole owner to ensure the structural integrity and safety of the electric lines.

10. Record-Keeping and Administration

Each joint-pole user shall perform the necessary administration and record-keeping to ensure that activities and responsibilities addressed in this policy and NESC Rule 214A-4 are being carried out.

Approved by Oregon Public Utility Commission on February 18, 1997