COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION

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COMMISSION

SECOND DATA REQUEST OF COMMISSION STAFF TO JURISDICTIONAL ELECTRIC DISTRIBUTION UTILIITES

CASE NUMBER 2006-00494

CLARK ENERGY

COOPERATIVE, INC

WINCHESTER, KENTUCKY

2640 Iron Works Road
Winchester, Ky. 40392-0748

CLARK ENERGY

A Touchstone Energy Cooperative

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PUBLIC SERVICE
COMMISSION

February 21, 2007

RESPONSE TO DATA REQUEST OF

THE KENTUCKY PUBLIC SERVICE COMMISSION

DUE ON OR BEFORE FEBRUARY 23, 2007

CASE NUMBER 2006-00494

Clark Energy Cooperative, Inc. ("Clark Energy"), pursuant to the Public Service Commission's (PSC) information request due on or before February 23, 2007, hereby submits the following response dated February 21st, 2007 regarding Case No. 2006-00494

Dated: February 21st, 2007

ATTEST:

Paul G. Embs

President & CEO

cc: Parties of record

Our power is our People

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF THE RELIABLITY MEASURES OF KENTUCKY'S JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES AND CERTAIN RELIABLITY MAINTENANCE PRCATICES	)))))	ADMINISTRATIVE CASE NO. 2006-00494	RECEIVED FEB 22 2007 PUBLIC SERVICE COMMISSION

SECOND DATA REQUEST OF COMMISSION STAFF TO JURISDICTIONAL ELECTRIC DISTRIBUTION UTILITIES

Jurisdictional electric distribution utilities ("distribution utilities") are requested, pursuant to 807 KAR 5:001, to file with the Commission the original and six copies of the following information, with a copy to all parties of record. The information requested herein is due on or before February 23, 2007. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 0f 6. Include with each response the name of the person who will be responsible for responding to questions relating to the information provided. Careful attention should be given to copied material to ensure that it is legible. Where information requested herein has been provided, in the format requested herein, reference may be made to the specific location of said information in responding to this information request. Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") may file one document as KU/LG&E including a separate response for each company within each tabbed response where necessary.

Administrative
Case No. 2006-00494

PSC Administrative Case No. 2006-00494

All electric-distribution utilities are to respond to the following questions:

Question 1. Describe in detail how the company utilizes all the reliability measures it monitors.

Answer 1. Clark Energy utilizes three different indices to monitor reliability on all of its individual substation circuits. SAIDI, SAIFI and CAIDI numbers from each circuit are compared against other substation circuits on a regional and system wide basis taking into consideration outage history for the past three years. Increases in the numbers of outages on any one particular circuit with a history of outages triggers increased monitoring of reports and line patrol of the affected area.

Clark Energy's service area is very diverse, ranging from farm land and suburbs in the western part of the system to mountainous terrain in the eastern part of the system. This diversity means that all substation circuits are not created equal because of differences in length of the circuit, circuit exposure to unusual amounts of vegetation, voltage, construction and age.

Area servicemen are a key resource in determining problems that surface or patterns that develop. Whenever problems are detected, servicemen are the first to be interviewed to see if they have any information pertaining to the outages.

Completed by Scott Sidwell

Pages 1 of 1

Question 2. Has the company determined an appropriate operating range or performance threshold based on these measures? If yes, identify.

Answer 2. No. Since the indices are averages, poor performing circuits can be influenced by the number or size of outages or the number or size of the customers on the circuit and either can skew the results. In some cases, an area can receive a disproportionate share of storms during any particular year or season making outage history very important in determining if there is truly a problem.

Question 3. Describe in detail how the company develops formal plans to address its worst performing circuits. If the company does not develop such plans, indicate so in the response.

Answer 3. Each outage, regardless of circuit size or performance, is scrutinized to see if reduction or elimination of the outage is possible. Detailed records are kept on outages in 32 different categories to break down causes in an effort to eliminate repeat outages and identify specific causes.

If trees within the rights-of-way are the cause, then a work order is issued to take care of the problem. In some cases where the cause might be equipment related or an animal problem, parts of the entire feeder may have animal guards added or that particular type of equipment changed out.

Long range plans include sectionalizing of lines on feeders that are performing poorly to reduce the size and scope of outages, something that Clark Energy has been very pro-active on in recent years and the inclusion of problem circuits that have a history of conductor deterioration and/or load problems into the construction work plan.

Question 4. Why are momentary outages excluded?

Answer 4. There are no practical or inexpensive ways of keeping records on momentary outages. Since each single "event" on an outage may include several breaker operations, reading the breaker counters would not yield the information that we are trying to obtain. With more than five hundred devices located on Clark Energy's system, of which the majority are not designed to report the information that we are trying to gather and no way of getting communications to those devices without extensive cost, then the cost-benefit ratio would show that the costs vastly out weight the benefits. Partial implementation or the use of SCADA to retrieve and report momentary substation outages would fail to show the whole picture.

Question 5. Why are major event days or major storms excluded?

Answer 5. Major storms and major event days are two different concepts when speaking of outage indices. Each utility has their own criteria of what constitutes a "Major storm" but these outages are not excluded from the yearly indice calculations. They are simply separated out to show the difference between "with extreme storms" and "without extreme storms".

Major storms are normally short in duration but these outages over a period of a few days can skew the outage numbers of utilities that could otherwise be shown to be very reliable. Distribution rights-of-ways standards and distribution line design criteria can not compensate for extreme ice loading, tornados and extreme wind shears simply because they are cost prohibitive.

"Major event days" calculations were not requested and not reported with our response to the first PSC information request. This concept is a fairly new way of calculating outages showing events above and beyond normal day-to-day outages and does not appear to be accepted by all as of yet.

Question 6. Provide a hard copy citing of the Rural Utilities Services ("RUS") reliability monitoring or reporting requirements or, in the alternative, provide an accessible internet site.

Answer 6. A copy of RUS Bulletin 161-1, Draft, entitled "Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems" is included with this document in Appendix C.

Question 7. Provide and describe in detail any service restoration or outage response procedure utilized.

Answer 7. This following service restoration plan document is included with our Emergency Response Plan adopted by Clark Energy.

SERVICE RESTORATION PLAN

Purpose

The purpose of the Service Restoration Plan is to ensure the most orderly, efficient, and safest continuity of electrical service to consumers and the safest environment to the public and workers in case of damage to electric facilities.

Statement of Intent

This document is meant to serve as a guide in restoration of electric service due to damage that might be incurred during severe weather, such as ice, windstorms, tornados or other acts of God, and the unpredictable negative acts of people such as sabotage. However, it must be understood that the infinite number of variables involved in natural and manmade disasters can never be completely accounted for in any document of this nature; thus, flexibility in actual procedures must be afforded managers and supervisors as they go about the tasks outlined in this document.

Priority of Restoration

Priority for restoration of service will be given to situations involving downed, energized power lines that endanger life and property.

Levels of Preparedness

The following conditions shall be used as a guideline for assessing the nature of the emergency or storm damage:

Condition green - Normal day-to-day management and operating routines are in effect.

Condition blue - This is an elevated condition requiring a minimal staffing of personnel. In-house crews can probably handle this situation and it may require that all cooperative personnel be placed on alert. Outages are small and scattered but conditions are right for further escalation.

Condition yellow **-** Prospects of major changes in operating conditions may require any or all personnel, contractors, and other resources be alerted for standby and/or assembly although the outage or emergency may not later actually develop or be smaller in scope than originally anticipated.

Condition red - Major changes in operating conditions are imminent or a large outage or emergency has occurred requiring mobilization and/or deployment of all appropriate resources. Resources may be released if the duration and scope of the outage or emergency is less than originally anticipated.

Determination of the Level of Involvement

1. What is the nature of the crisis?
2. What is the number of consumers involved?
3. What is the number of substation or circuits involved?
4. What is the level of priority for the affected circuits?
    A. dangerous or potentially life threatening situation
    B. hospital, health care facilities and other emergency operations
    C. consumers with health priorities
    D. main distribution lines
    E. isolated outages at homes or businesses
    F. all others

Service Restoration Procedure

Upon notification of service interruption or report of a hazardous condition to the 24-hour dispatch center, a service interruption report will be filed and repair personnel will be informed of the outage or the location of the hazardous condition. Upon arrival at the source of the service interruption, the service crew will determine the safest and the most efficient manner in which to restore service.

If additional personnel or equipment is needed, the crew shall report back to the dispatch coordinator or the outage coordinator who shall determine the level of response to initiate. In all cases, communications will take place before restoration of energizing of lines occurs.

Extraordinary Outage Conditions

Upon receiving indications of more service outages than available manpower will allow a timely response to, a determination of the degree of hazard or work required for repairs will be made by dispatching qualified personnel to survey outage conditions. The survey personnel will evaluate the extent of the damage and report to the outage coordinator their estimates of manpower and equipment requirements, estimated time of repairs, and any safety recommendations.

All reportable outage conditions will be reported to the Kentucky Public Service Commission in accordance with appropriate requirements by the president & CEO or an alternate to whom he/she has assigned the responsibility.

Record Keeping

Complete, accurate, and appropriate outage and repair records will be maintained at all times.

Question 8. Refer to the RUS drawing M1.30G "RIGHT-OF-WAY CLEARING GUIDE" ("ROW Guide"), a copy has been provided in Appendix A.

a. Is this type of clearance requirement appropriate for all areas of a distribution system? If not, what types of exclusions or exceptions should be made?

Answer 8(a). The drawing referred to in Appendix A is not a detailed right-of-way clearing guide but rather a statement of desired clearances for overhead lines. Most coops set their own guidelines for trimming in and around urban areas keeping the RUS specifications in mind.

Question 8(b).	If the distribution utility is not already following this guide, provide an estimate of the cost and time-line to implement.
Answer 8(b).	Clark Energy currently adheres to guideline M1.30G "RIGHT-OF-WAY CLEARING GUIDE" on single and three phase feeders in a rural setting as this specification is designed for.

Question 9. Refer to North American Electric Reliability Corporation ("NERC") standard FAC-003-1 "transmission Vegetation Management Program" ("NERC Standard"), a copy is attached in Appendix B.

a. Does the company prefer the type of standard described in the NERC Standard over the type of standard described in the ROW Guide? Explain why you prefer one over the other.

Answer 9(a). No, Clark Energy does not prefer the type of standard described in the NERC Standard over the type of standard described in the ROW Guide. It appears that the NERC Standard is a transmission standard that does not fit distribution needs due to the fact that transmission and distribution rights-of-ways are completely different in design and operation.

Question 9(b). Refer to section R3 of the NERC Standard and substitute "distribution" for "transmission". Is the distribution utility capable of meeting the reporting requirements described in the section? If not, why not?

Answer 9(b). Yes, Clark Energy is capable of meeting the reporting requirement; but it appears that the NERC Standard is a transmission standard that does not fit distribution needs due to the fact that transmission lines and distribution lines are completely different in design and operation.

Question 9(c). Again referring to section R3 as applied to distribution, how many sustained outages would be reportable for the calendar year 2006?

Answer 9(c) The following statement was copied from Appendix B;

"R3.2. The ~~Transmission~~ Distribution Owner is not required to report to the RRO, or the RRO's designee, *certain sustained transmission line outages* caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the ~~Transmission~~ Distribution Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activities that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

Considering that a large number of the outages reported by Clark Energy each year are a result of high winds or wind shears off of thunderstorms or severe weather systems, Clark Energy's reliability numbers for 2006 could be reduced significantly if reporting requirements were changed. Approximately 35% of the outage hours reported last year were a result of trees blowing into distribution lines from outside the rights-of-way due to high winds.

Completed by Scott Sidwell Pages 3 of 3

Question 10. Provide and discuss any right-of-way maintenance standard which is preferable to those identified in questions 1 and 2 above.

Answer 10. CRN (Cooperative Research Network), sponsored by NRECA has written a comprehensive publication called "Vegetation Management – Project 98-08 dealing with every aspect of distribution rights-of-way clearing from "Steps in Developing an Effective Program" to "Public relations" to "proper pruning techniques", just to name a few of the chapters. I am including a copy of chapter 4 entitled "Work Practices" as an example, located in Appendix D of this document. This would seem to be better than taking a transmission document and trying to adapt it to distribution Rights-of-way clearing.

PSC Administrative Case No. 2006-00494

Clark Energy is to respond to the following question:

Question 19. Describe the value of the measures described in items 1 thru 4 of Clark's response to Question No. 1 in Staff's first data request.

This is Question 1, part a, from the Staff's first data request restated:

Question No. 1: Does utility management measure, monitor, or track distribution reliability?

Answer: Yes.

Part a: If so, describe the measures used and how they are calculated.

Answer: Detail accounts of system outages are entered into Milsoft's Utility Solutions Dispatch Software program as they occur noting all pertinent information. Multiple reports are then available to break the outages into manageable data for evaluation.

Some of the most used reports are as follows:

1. **Devices out multiple times – Helps track down reoccurring problems**

2. **Outage cause report – contains information on specific causes (a list of causes are included later in this report) and equipment failure (highlights faulty materials and equipment)**

3. **Customers affected by area – lists numbers of customers still off in an area during an outage.**

4. **Monthly outages – reports are made monthly to Clark Energy's board of directors**

5. Monthly outages by feeder – lists substation and individual circuit outage numbers.

RUS requires Cooperatives to track and report an indice on their annual form 7 financial and statistical report with the acronym SAIDI (system average interruption duration frequency index) that measures the total duration of interruptions that a customer would see on average each year. One factor added into this equation is extreme storm, which is included in the reliability chart listed later in this report

Another indice reviewed by utility management is CAIDI (customer average interruption duration frequency) which measures how efficient we are in restoring service after an interruption.

Internal corporate reliability goals were set and monitored by our board of directors in 2006 so they could see what level of reliability the cooperative is providing.

Answer to Question 19 of "Second Data Request of Commission Staff to Jurisdictional Electric Distribution Utilities"

Answer 1 - 4 of question 1 illustrates the type of reports that assist Clark Energy in measuring, monitoring, and tracking distribution reliability.

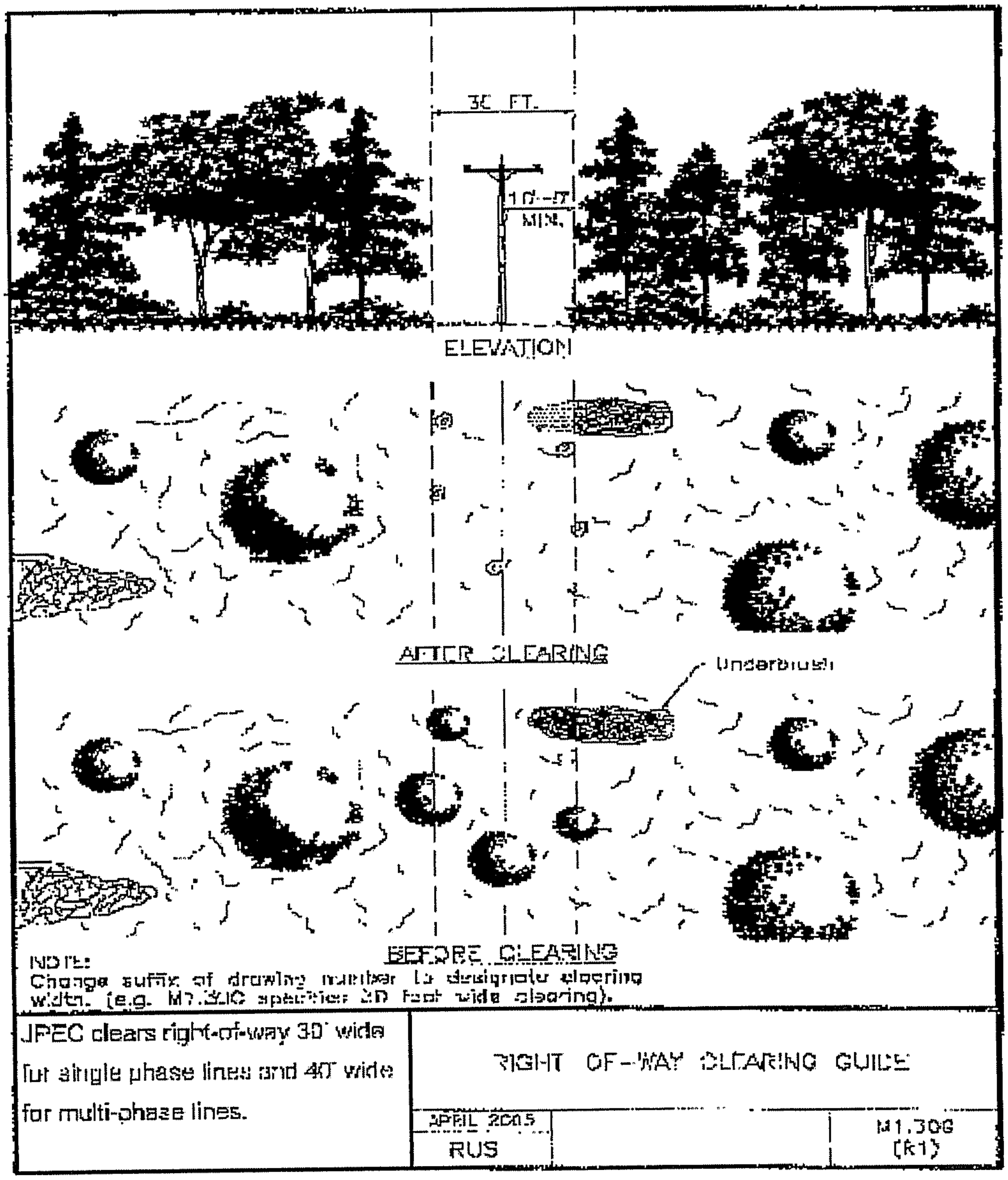
The "Devices out multiple times" report addressed in answer 1 helps us monitors repeat outages to determine if an area has problems that occur over a period of months in such a fashion that they are not detected under normal scrutiny.

Answer 2 deals with a report that we use to monitor causes to search for trends in outages such as a particular type of equipment failing or a specific area that has higher than normal outages because of rights-of-way issues or other such causes.

Information contained in the "Customer's affected by area" report noted in answer 3 will be used to keep our customers informed via the internet or local media outlets in times of extreme weather or circumstances and information to meet the PSC reporting requirement will be gleaned from this report as well.

And finally, the "Monthly Outages" report measures and tracks our monthly outages in comparison to corporate goals that are reported to our board of directors at each monthly board meeting.

Appendix A


30 FT.
10'-0" MIN.
ELEVATION
AFTER CLEARING
Underbrush
BEFORE CLEARING
NOTE:
Change suffix of drawing number to designate clearing width. (e.g. M1.30G specifies 30 foot wide clearing).
JPEC clears right-of-way 30' wide for single phase lines and 40' wide for multi-phase lines.
RIGHT OF-WAY CLEARING GUIDE
APRIL 2005
RUS
M1.30G
(k1)

Appendix B

A. Introduction

1 **Title: Transmission Vegetation Management Program**
2 **Number:** FAC-003-1
3 **Purpose:** To improve the reliability of the electric transmission systems by preventing outages from vegetation located on transmission rights-of-way (ROW) and minimizing outages from vegetation located adjacent to ROW, maintaining clearances between transmission lines and vegetation on and along transmission ROW, and reporting vegetation-related outages of the transmission systems to the respective Regional Reliability Organizations (RRO) and the North American Electric Reliability Council (NERC).
4. Applicability:
4.1. Transmission Owner.
4.2. Regional Reliability Organization.
4.3. This standard shall apply to all transmission lines operated at 200 kV and above and to any lower voltage lines designated by the RRO as critical to the reliability of the electric system in the region.
5 Effective Dates:

5.1. One calendar year from the date of adoption by the NERC Board of Trustees for Requirements 1 and 2.

5.2. Sixty calendar days from the date of adoption by the NERC Board of Trustees for Requirements 3 and 4.

B. Requirements

R1. The Transmission Owner shall prepare, and keep current, a formal transmission vegetation management program (TVMP). The TVMP shall include the Transmission Owner's objectives, practices, approved procedures, and work specifications1 .

R1.1. The TVMP shall define a schedule for and the type (aerial, ground) of ROW vegetation inspections. This schedule should be flexible enough to adjust for changing conditions. The inspection schedule shall be based on the anticipated growth of vegetation and any other environmental or operational factors that could impact the relationship of vegetation to the Transmission Owner's transmission lines.

R1.2. The Transmission Owner, in the TVMP, shall identify and document clearances between vegetation and any overhead, ungrounded supply conductors, taking into consideration transmission line voltage, the effects of ambient temperature on conductor sag under maximum design loading, and the effects of wind velocities on conductor sway. Specifically, the Transmission Owner shall establish clearances to be achieved at the time of vegetation management work identified herein as Clearance 1, and shall also establish and maintain a set of clearances identified herein as Clearance 2 to prevent flashover between vegetation and overhead ungrounded supply conductors.

R1.2.1. Clearance 1 — The Transmission Owner shall determine and document appropriate clearance distances to be achieved at the time of transmission vegetation management work based upon local conditions and the expected time frame in which the Transmission Owner plans to return for future vegetation management work. Local conditions may include, but are not limited to: operating voltage, appropriate vegetation management techniques, fire risk, reasonably anticipated tree and conductor movement, species types and growth rates, species failure characteristics, local climate and rainfall patterns, line terrain and elevation, location of the vegetation within the span, and worker approach distance requirements. Clearance 1 distances shall be greater than those defined by Clearance 2 below.

R1.2.2. Clearance 2 — The Transmission Owner shall determine and document specific radial clearances to be maintained between vegetation and conductors under all rated electrical operating conditions. These minimum clearance distances are necessary to prevent flashover between vegetation and conductors and will vary due to such factors as altitude and operating voltage. These Transmission Owner-specific minimum clearance distances shall be no less than those set forth in the Institute of Electrical and Electronics Engineers (IEEE) Standard 516-2003 (*Guide for Maintenance Methods on Energized Power Lines*) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

R1.2.2.1 Where transmission system transient overvoltage factors are not known, clearances shall be derived from Table 5, IEEE 516-2003, phase-to-ground distances, with appropriate altitude correction factors applied.

R1.2.2.2 Where transmission system transient overvoltage factors are known, clearances shall be derived from Table 7, IEEE 516-2003, phase-to-phase voltages, with appropriate altitude correction factors applied.

R1.3. All personnel directly involved in the design and implementation of the TVMP shall hold appropriate qualifications and training, as defined by the Transmission Owner, to perform their duties.

R1.4. Each Transmission Owner shall develop mitigation measures to achieve sufficient clearances for the protection of the transmission facilities when it identifies locations on the ROW where the Transmission Owner is restricted from attaining the clearances specified in Requirement 1.2.1.

R1.5. Each Transmission Owner shall establish and document a process for the immediate communication of vegetation conditions that present an imminent threat of a transmission line outage. This is so that action (temporary reduction in line rating, switching line out of service, etc.) may be taken until the threat is relieved.

R2. The Transmission Owner shall create and implement an annual plan for vegetation management work to ensure the reliability of the system. The plan shall describe the methods used, such as manual clearing, mechanical clearing, herbicide treatment, or other actions. The plan should be flexible enough to adjust to changing conditions, taking into consideration anticipated growth of vegetation and all other environmental factors that may have an impact on the reliability of the transmission systems. Adjustments to the plan shall be documented as they occur. The plan should take into consideration the time required to obtain permissions or permits from landowners or regulatory authorities. Each Transmission Owner shall have systems and procedures for documenting and tracking the planned vegetation management work and ensuring that the vegetation management work was completed according to work specifications.

R3. The Transmission Owner shall report quarterly to its RRO, or the RRO's designee, sustained transmission line outages determined by the Transmission Owner to have been caused by vegetation.

R3.1. Multiple sustained outages on an individual line, if caused by the same vegetation, shall be reported as one outage regardless of the actual number of outages within a 24hour period.

R3.2. The Transmission Owner is not required to report to the RRO, or the RRO's designee, certain sustained transmission line outages caused by vegetation: (1) Vegetation-related outages that result from vegetation falling into lines from outside the ROW that result from natural disasters shall not be considered reportable (examples of disasters that could create non-reportable outages include, but are not limited to, earthquakes, fires, tornados, hurricanes, landslides, wind shear, major storms as defined either by the Transmission Owner or an applicable regulatory body, ice storms, and floods), and (2) Vegetation-related outages due to human or animal activity shall not be considered reportable (examples of human or animal activity that could cause a non-reportable outage include, but are not limited to, logging, animal severing tree, vehicle contact with tree, arboricultural activities or horticultural or agricultural activities, or removal or digging of vegetation).

R3.3. The outage information provided by the Transmission Owner to the RRO, or the RRO's designee, shall include at a minimum: the name of the circuit(s) outaged, the date, time and duration of the outage; a description of the cause of the outage; other pertinent comments; and any countermeasures taken by the Transmission Owner.

R3.4. An outage shall be categorized as one of the following:

R3.4.1. Category 1 — Grow-ins: Outages caused by vegetation growing into lines from vegetation inside and/or outside of the ROW;

R3.4.2. Category 2 — Fall-ins: Outages caused by vegetation falling into lines from inside the ROW;

R3.4.3. Category 3 — Fall-ins: Outages caused by vegetation falling into lines from outside the ROW.

R4. The RRO shall report the outage information provided to it by Transmission Owner's, as required by Requirement 3, quarterly to NERC, as well as any actions taken by the RRO as a result of any of the reported outages.

C. Measures

M1. The Transmission Owner has a documented TVMP, as identified in Requirement 1.

M1.1. The Transmission Owner has documentation that the Transmission Owner performed the vegetation inspections as identified in Requirement 1.1.

M1.2. The Transmission Owner has documentation that describes the clearances identified in Requirement 1.2.

M1.3. The Transmission Owner has documentation that the personnel directly involved in the design and implementation of the Transmission Owner's TVMP hold the qualifications identified by the Transmission Owner as required in Requirement 1.3.

M1.4. The Transmission Owner has documentation that it has identified any areas not meeting the Transmission Owner's standard for vegetation management and any mitigating measures the Transmission Owner has taken to address these deficiencies as identified in Requirement 1.4.

M1.5. The Transmission Owner has a documented process for the immediate communication of imminent threats by vegetation as identified in Requirement 1.5.

M2. The Transmission Owner has documentation that the Transmission Owner implemented the work plan identified in Requirement 2.

M3. The Transmission Owner has documentation that it has supplied quarterly outage reports to the RRO, or the RRO's designee, as identified in Requirement 3.

M4. The RRO has documentation that it provided quarterly outage reports to NERC as identified in Requirement 4.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Monitoring Responsibility

   RRO

   NERC

   1.2. Compliance Monitoring Period and Reset

   One calendar Year

   1.3. Data Retention

   Five Years

   1.4. Additional Compliance Information

   The Transmission Owner shall demonstrate compliance through self-certification submitted to the compliance monitor (RRO) annually that it meets the requirements of NERC Reliability Standard FAC-003-1. The compliance monitor shall conduct an on-site audit every five years or more frequently as deemed appropriate by the compliance monitor to review documentation related to Reliability Standard FAC-003-1. Field audits of ROW vegetation conditions may be conducted if determined to be necessary by the compliance monitor.

2. Levels of Non-Compliance

   2.1. Level 1:

   2.1.1. The TVMP was incomplete in one of the requirements specified in any subpart of Requirement 1, or;

   2.1.2. Documentation of the annual work plan, as specified in Requirement 2, was incomplete when presented to the Compliance Monitor during an on-site audit, or;

   2.1.3. The RRO provided an outage report to NERC that was incomplete and did not contain the information required in Requirement 4.

   2.2. Level 2:

   2.2.1. The TVMP was incomplete in two of the requirements specified in any subpart of Requirement 1, or;

   2.2.2. The Transmission Owner was unable to certify during its annual self-certification that it fully implemented its annual work plan, or documented deviations from, as specified in Requirement 2.

   2.2.3. The Transmission Owner reported one Category 2 transmission vegetation-related outage in a calendar year.

   2.3. Level 3:

   2.3.1. The Transmission Owner reported one Category 1 or multiple Category 2 transmission vegetation-related outages in a calendar year, or;

   2.3.2. The Transmission Owner did not maintain a set of clearances (Clearance 2), as defined in Requirement 1.2.2, to prevent flashover between vegetation and overhead ungrounded supply conductors, or;

2.3.3. The TVMP was incomplete in three of the requirements specified in any subpart of Requirement 1.

2.4. Level 4:

2.4.1. The Transmission Owner reported more than one Category 1 transmission vegetation-related outage in a calendar year, or;

2.4.2. The TVMP was incomplete in four or more of the requirements specified in any subpart of Requirement 1.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
Version 1	TBA	1. Added "Standard Development Roadmap." 2. Changed "60" to "Sixty" in section A, 5.2. 3. Added "Proposed Effective Date: April 7, 2006" to footer. 4. Added "Draft 3: November 17, 2005" to footer.	01/20/06

DRAFT
RUS BULLETIN 161-1

"Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems"

I. PURPOSE AND SCOPE

This bulletin provides guidance on recording and reporting service interruptions/outages, and the calculation of industry standard indices for measuring distribution system performance.

II. DEFINITIONS

AMR (Automated Meter Reading)

Interruption: A loss of electricity for any period longer than 5 minutes.

IEEE: The Institute of Electrical and Electronics Engineers.

IVR: Interactive Voice Response.

Outage: The state of a component when it is not available to perform its intended function due to some event directly associated with that component. An outage may or may not cause an interruption o fservice to customers, depending on system configuration. This definition does not apply to generation outages.

SAIDI: System Average Interruption Duration Index.

SCADA: Supervisory Control and Data Acquisition.

Power Supply Interruption: Any interruption coming from the transmission system or the substation (even if the distribution system owns the substation or transmission system). If a distribution system owns a sub-transmission system, it and the sub-transmission to distribution substations are considered part of the distribution system. Not included are any substation breakers that go to lockout because of a fault on the distribution system. If there a delivery point is on the distribution system, interruptions caused by something on the source side of the delivery point would be considered a "power supply" outage.

Major Event: This is defined in IEEE Standard 1366-2004 and in Appendix 5 of this document. A major event represents an interruption or group of interruptions caused by conditions that exceed the design and operational limits of the system.

Major Event Day: A day in which the daily SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

Prearranged Interruption: Any interruption scheduled by the distribution system in order for it to safely perform routine maintenance.

All Other Interruptions: All interruptions excluding power supply, major storm, and prearranged.

III. INTERRUPTION REPORTING

A. The Trouble Ticket

The generation of a trouble ticket is the first step in interruption reporting. The first goal of the trouble ticket is to get as much information as possible about the interruption and to pass this information along quickly to the people or systems that need it.

A trouble ticket is traditionally the result of a telephone call from a member reporting a service problem or interruption. These telephone calls have historically been taken by a customer service representative (CSR) using a manual "trouble ticket" form. However, with newer technology, cooperatives can automate this process and render the traditional trouble ticket paperless.

Cooperative personnel should give thought to the process of interruption data-gathering, reporting, and analysis and make a determination of the point at which this data should enter into an electronic format. Because of the flexibility of software systems and the advent of services and products like call centers and interactive voice response systems, the cooperative has many choices to improve its performance in this area.

1. Manual Trouble Ticket
The simplest interruption reporting is the use of a form as shown in Appendix 1. A cooperative employee could fill out this type form manually as they talk to the member on the phone. This same form could be used to dispatch crews and report the cause of the interruption and other pertinent information, making a complete record of the interruption report. It would be used to generate any interruption analysis or reports the cooperative may find useful.

2. Automated Trouble Ticket
Technology available today provides faster response to larger call volumes and allows for interruption data to be quickly assimilated into a computerized outage management system. The result is faster response and restoration times, as well as

increased customer satisfaction. There are several methods for generating the automated trouble ticket, including, but not limited to, the use of SCADA, AMR, IVR and call centers. For more discussion on these options, see Appendix 3 on page 17.

B. The Interruption Report

The interruption report is used to document a service interruption. Typically, an interruption report is completed each time a sectionalizing device opens permanently for the purpose of clearing a fault or de-energizing a section of line for construction or maintenance.

The report should provide enough information to comply with RUS and the state's public service commission reporting requirements for service reliability/continuity. Additionally, the form should capture information that will enable the Coop to calculate industry standard reliability indices, as well as to determine the effectiveness of various maintenance activities performed by the Cooperative.

A sample Interruption Report is included in Appendix 2.

C. Reports to RUS

Cooperatives that borrow funds from RUS are required to report the system average annual interruption minutes per consumer on Form 7 and Form 300. Shown below is Part G of Form 7 (Figure 1). The value used in this report is called SAIDI, System Average Interruption Duration Index. It is defined in detail in the Definitions Section of this Bulletin.

Part G. Service Interruptions					
Item	SAIDI (in minutes)				
	Power Supply (a)	Major Event (b)	Planned (c)	All Other (d)	TOTAL (e)
1. Present Year					
2. Five-Year Average					

Figure 1 – RUS Form 7 Part G

Form 7 calls for four separate SAIDIs as well at the total interruption time. The definitions of the terms used in Part G can be found in Part II, "Definitions".

IV. INTERRUPTION ANALYSIS

In addition to RUS reporting requirements, it is recommended that Cooperatives track additional information about service interruptions for more detailed analysis. The purpose of additional analysis is to provide feedback to the Coop's employees, management and board on how well the distribution system is serving the members.

There have traditionally been two codes associated with interruption reporting: cause codes and equipment codes. Every interruption has a cause, but not every interruption results in damaged or failed equipment, such as a recloser properly de-energizing a feeder when contacted by a tree limb. It is important to recognize the distinction between the cause of an interruption other than failed equipment, and a particular piece of equipment that is damaged or needs to be replaced. In the case where no equipment was damaged, the corresponding code in Figure 4, "0999, No Equipment Failure" would be used. Therefore, every interruption will have a cause code and an equipment code associated with it even when no equipment is at fault. Recommended cause codes are shown in Figure 3, and equipment codes are shown in Figure 4.

Weather Condition Codes indicate the conditions that existed when the interruption occurred; it is not to be confused with the cause code that indicates a weather component that might have initiated it. These are shown in Figure 5.

Voltage Level Codes can be used to identify system behavior that is a function of the operating voltage on the damaged components at the time of the interruption. The table in Figure 6 indicates the phase-to-phase voltage level, as some systems operate "Wye" configurations and others operate "Delta" configurations. It is generally accepted that higher voltage systems are more susceptible to lightning damage because of different Basic Insulation Levels (BIL). The cooperative engineer may be able to determine other improvements based on this data as well.

The codes are formatted such that summary and high level reports are easy to produce based on the data in the interruption report. The cooperative may choose to use additional codes for more detailed information and analysis. It is important to note that these tables link together the codes that the cooperative may use, as in the first column, and the codes prescribed by RUS and by IEEE.

Cause Codes			
Coop Code	**RUS FORM 7, Part G, Column**	**IEEE CODE**	**Description**
			Power Supply[1]
000	a	4	Power Supply
			Planned Outage
100	c	3	Construction
110	c	3	Maintenance
190	c	3	Other prearranged

[1] This cause code is used for outages caused by something on equipment not owned by the Distribution Cooperative. If an interruption is caused by something on the cooperative's own transmission system, then a specific cause should be used.

[2] This cause code should only contain those major event days that are determined using the IEEE "Beta Method" described in Part C of this section.

[3] Interruptions marked as "Cause Unknown" should be further investigated to try to determine probable cause.

			Equipment or Installation/Design
300	d	1	Material or Equipment Fault/Failure
310	d	10	Installation Fault
320	d	10	Conductor Sag or Inadequate Clearance
340	d	10	Overload
350	d	10	Miscoordination of Protection Devices
360	d	10	Other Equipment Install/Design
			Maintenance
400	d	1	Decay/Age of Material/Equipment
410	d	1	Corrosion/Abrasion of Material/Equipment
420	d	6	Tree Growth
430	d	6	Tree Failure from Overhang or Dead Tree without ice/snow
440	d	6	Trees with ice/snow
450	d	1	Contamination (Leakage/External)
460	d	1	Moisture
470	d	6	Cooperative Crew Cuts Tree
490	d	10	Maintenance Other
			Weather
500	d	2	Lightning
510	d	7	Wind Not Trees
520	d	7	Ice, Sleet, Frost Not Trees
530	d	7	Flood
590	d	10	Weather Other
			Animals
600	d	8	Small Animal/Bird
610	d	8	Large Animal
620	d	8	Animal Damage -- Gnawing or Boring
690	d	8	Animal Other
			Public
700	d	5	Customer-Caused
710	d	5	Motor Vehicle
720	d	5	Aircraft
730	d	5	Fire
740	d	6	Public Cuts Tree
750	d	5	Vandalism
760	d	10	Switching Error or caused by construction/maintenance activities
790	d	10	Public Other
			Other
800	d	10	Other
			Unknown[3]
999	d	9	Cause Unknown

Figure 3 – Cause Codes

Equipment Failure Codes	
Coop Code	**Description**
	Generation or Transmission
010	Generation

020	Towers, poles and fixtures
030	Conductors and devices
040	Transmission substations
090	*Generation or Transmission other*
	Distribution Substation
100	Power transformer
110	Voltage regulator
120	Lightning arrester
130	Source side fuse
140	Circuit breaker
150	Switch
160	*Metering equipment*
190	Distribution substation Other
	Poles and Fixtures, Distribution
200	Pole
210	Crossarm or crossarm brace
220	Anchor or guy
290	Poles and Fixtures Other
	Overhead Line Conductors and Devices, Distribution
300	Line Conductor
310	Connector or clamp
320	Splice or deadend
330	Jumper
340	Insulator
350	Lightning arrester line
360	Fuse cutout (damaged, malfunction, maintenance)
370	Recloser or sectionalizer (damaged, malfunction, maintenance)
390	Overhead line conductors and devices, distribution other
	Underground Line Conductors and Devices, Distribution
400	Primary Cable
410	*Splice or fitting*
420	Switch
430	Elbow arrester
440	Secondary cable or fittings
450	Elbow
460	Pothead or terminator
490	Underground other
	Line Transformer
500	*Transfromer bad*
510	Transformer fuse or breaker
520	Transformer arrester
590	Line transformer other
	Secondaries and Services
600	Secondary or Service Conductor
610	Metering equipment
620	Security or street light

690	Secondary and service other
	No Equipment Damaged
999	No Equipment Failure

Figure 4 – Equipment or Material Responsible for Interruption

Weather Codes	
010	Rain
020	Lightning
030	Wind
040	Snow
050	Ice
060	Sleet
070	Extreme Cold
080	Extreme Heat
090	Weather Other
100	Clear, calm

Figure 5 – Weather Codes

Voltage Level Codes	
001	< KV(Secondary/Low Voltage)
002	5 KV
003	15 KV
004	25 KV
005	35 KV
006	60 KV
007	> 60 KV

Figure 6 – Voltage Level Codes

A. Use and Analysis of Interruption Data

The time spent collecting the data described above will be wasted unless it is analyzed and the results used as a tool to improve the distribution system performance.

There are many ways the data can be useful. For example, interruption records, which included data on equipment failures, led utilities to discover that two lightning arrester manufacturers had bad batches of arresters which were resulting in premature failures. Another utility used information on lightning damage and location to determine lightning prone areas in their territory. They then selectively improved the grounding only in these areas. This resulted in a least-cost reduction in interruptions due to lightning and also reduced equipment damage.

The goal of all of this is to reduce the number and duration of interruptions. To determine if you are spending your money wisely and truly reducing interruptions, you must keep consistent data over many years to show trends.

B. Definition And Use of the Major Indices

In this section we will discuss the definition of the most significant interruption-related indices and calculations. The following three indices should be calculated:

SAIDI-- System Average Interruption Duration Index
SAIFI-- System Average Interruption Frequency Index
CAIDI-- Customer Average Interruption Duration Index

The IEEE Standard 1366-2004[3] defines SAIDI as the total duration of interruption for the average customer during a predefined period of time (usually one calendar year). It is measured in customer minutes.

$$\text{SAIDI} = \frac{\text{Sum of Customer Interruption Durations (over the period desired)}}{\text{Total Number of Customers Served}}$$

As stated above, SAIDI is usually calculated for a calendar year or "year-to-date", but for major event calculations, **daily** SAIDI values should be recorded. The starting time for the duration of the interruption calculation is determined by the time the cooperative knows about the interruption either by automated means or by the first phone call from the affected area. Interruptions where the customer indicates that the repair can be scheduled for a later date should be counted as an interruption, but with a duration being the estimated amount of time required to repair the problem, including travel time.

The total number of customers served is the average number of customers served over the defined time period. (The sum of the monthly customer count divided by the number of months.) This number should be the same as on the RUS Form 7 except that Public Street and Highway Lighting should not be included. (Security or safety lights, billed to a residential customer, should not be counted on the Form 7)

SAIFI is the number of interruptions that the average customer experiences during the year (or month or day). Interruption recovery time has no effect on this index.

$$\text{SAIFI} = \frac{\text{Total number of customers interrupted}}{\text{Total number of customers served}}$$

CAIDI is the average amount of time that a customer is without power for a typical interruption. It is primarily determined by response time to a reported interruption. However, the number of customers affected by an interruption can affect CAIDI because

[3] Guide for Electric Power Distribution Reliability Indices. IEEE P1366-2004, Copyright © 2003 by the Institute of Electrical and Electronic Engineers, Inc.

the distribution system has limited resources to respond to an interruption that covers an extensive portion of their territory.

$$\mathrm{CAIDI} = \frac{\mathrm{SAIDI}}{\mathrm{SAIFI}}$$

C. Determination of a Major Event

There are certain things that are beyond the control of the distribution system, primarily natural disasters. Form 7 requires that the SAIDI for these interruptions be reported separately in Part G, Column (b), "Major Event" and not be included in Part G, Column (d), "All Other".

To date there has been no hard and fast rule of what constitutes a major event. It was usually defined as an event that lasted a specified period of time and which caused an interruption for at least a specified number of customers.

For example, an ice storm that results in interruptions of up to ten days and causes an interruption for 80% of customers is clearly a major event. In this case, the interruption records would be kept separately for this event. In calculating the SAIDI for the year, the interruptions from this event should be included in Column b.

What about a severe thunderstorm that caused some customers interruptions of up to 25 hours and where 5% of the customer experience some kind of interruption because of it? Is this a major event or not? Some distribution systems would say yes and others would say no.

It is very desirable to be more consistent across the nation and to take into account the fact that distribution systems with lower SAIDI's should have a lower threshold for what constitutes a "Major Event". The IEEE Working Group on System Design within the Distribution Subcommittee has carefully analyzed the situation and has developed a statistical approach to determine a threshold daily SAIDI level that determines a "Major Event Day". They have defined a major event as a interruption or series of interruptions that exceeds reasonable design and or operational limits of the electric power system. With the issuance of this Bulletin, RUS encourage all cooperatives to start using this approach. All outages that occur during a day determined to be a Major Event Day should be reported in RUS Form 7, Part G, Column (b).

This methodology is fully described in IEEE 1366, "Guide for Electric Power Distribution Reliability Indices" and in Appendix A of this Bulletin. The calculation involves taking the daily SAIDI values for the last five years and taking the natural logarithm of each value in the data set. For those who have an automated system of recording reliability information, this calculation should be easily obtainable. For those who use a manual system, RUS has developed a simple Access Database Form to determine the threshold level for major event days. The form is available to download from the RUS web site http://www.usda.gov/rus/electric/forms/index.htm.

The Interruption Reporting Form (Appendix A) is utilized to calculate the values required on RUS form 7, Part G. No other analysis is performed by this database.

D. Step Restoration Process

When service is restored in several steps, the calculations should be made separately and then added together. The explanation used by the IEEE can be found in appendix 5.

V. SERVICE CONTINUITY OBJECTIVES

A. Demand For Good Service

Rural electric systems now provide power to everything from the peanut farm to the computer network server farm. As utility service entities, cooperatives should strive to provide the level of service needed by the load, consistent with the cost the customer is willing to bear. Approaching reliability from the customer's perspective will help cooperative personnel develop appropriate levels of service for the customer's benefit. A goal may be to improve the CAIDI for a feeder by 20 minutes, or it may be to reach an "Average System Availability Index (ASAI) of "four nines" (99.99%).

In some instances, extreme levels of reliability may be needed which are beyond the cooperative's ability to provide when considering such things as feeder lengths or degree of environmental exposure, frequency of storms, extreme terrain, cost, etc. A joint approach may be used that involves adding facilities on the customer's premises that are owned and maintained by the customer, to achieve these high requirements. The cooperative may agree to meet a minimum reliability number supplemented by customer-owned backup equipment.

RUS guidelines for service reliability should take into consideration those areas that are controllable by the individual borrower and those items that are not. All interruption categories should be analyzed to determine if they are acceptable with regard to customer expectations. The cooperative should look at each category when determining/modifying operating and design practices/criteria. The Power Supplier should be consulted if Power Supply interruptions are excessive. For RUS Form 300, Part II, 7(a), the "All Other" classification will be the primary category for evaluation. The table below shows the current RUS guideline:

Description	All Other SAIDI, In Minutes
Satisfactory (rating of 3)	200 or less
Should Be Explained (rating of 2 or less)	More than 200

B. Establishing Reliability Objectives

When the cooperative sets a goal of reliability, personnel can then take a proactive role in bringing it about through system planning and budgeting. A thorough analysis of interruption causes, number of accounts affected, and durations can tell the engineering and operations staff where to concentrate their efforts. Listed below are several areas to consider for review:

Right-of-Way Clearing	Sectionalizing Scheme
Level of Lightning Protection	Response Time
System Grounding	Personnel Deployment
Pole Treatment/Maintenance	Use of Wildlife Guards
Construction Practices	Loading Levels for Ice and Wind
Level of System Automation	Line Patrolling Activities

By prioritizing likely contributors of interruptions, the engineer is better able to target capital expenditures for the near term to improve the system's overall performance. Long-term benefits of pursuing a continuous improvement in reliability include increased customer satisfaction, lower maintenance expenses, lower demands on operations personnel, better system performance during extreme weather events, and improved safety for lineworkers and the general public. Specific action to be taken by the cooperative to achieve or maintain a satisfactory interruption level should be addressed in the Construction Work Plan.

3. Other Indices

There are several other indices that the cooperative might want to use. Three of these-- SAIFI, SAIDI, and CAIDI-- were discussed above. One other that might be considered is MAIFI (Momentary Average Interruption Frequency Index). This is a measure of the number of breaker operations that do not go to lock-out. This could be used as means to measure system coordination. It might also be used as one measure of the quality of the power supply by recording momentary transmission interruptions.

4. Normalization For Weather

The weather varies across the country. It also varies from year to year. Most thunderstorms are not considered major events but they can have a dramatic effect on the number of customer interruptions throughout the year. By normalizing the interruption data to a "typical" year with regards to lightning, it is possible to see more clearly the condition of the system. A plot of the number of customer interruptions versus the number of cloud-to-ground lightning strikes may illuminate a system's improvement in protection, or decline if arrestors and grounding are not maintained.

Appendix 1

Manual Trouble Ticket

<table>
<tr><td colspan="3">TROUBLE TICKET</td><td colspan="3"></td></tr>
<tr><td>DATE</td><td>TIME</td><td colspan="4">RECEIVED BY</td></tr>
<tr><td colspan="2">ACCOUNT NO.</td><td>REPORTED BY</td><td colspan="2">PHONE NO.</td><td>TIME POWER WENT OFF</td></tr>
<tr><td colspan="2" rowspan="3">☐ SERVICE OFF ENTIRELY
☐ NEIGHBORS ALSO OFF
☐ SERVICE DROP DOWN
☐ LIGHTS DIM
☐ CHECKED FUSES</td><td colspan="4">ADDRESS</td></tr>
<tr><td colspan="4">CAUSE</td></tr>
<tr><td colspan="4">LOCATION OF CAUSE</td></tr>
<tr><td colspan="2">RECLOSER OR TAP LOCATION</td><td colspan="2">ASSIGNED TO</td><td>TIME</td><td>TRUCK NO.</td></tr>
<tr><td colspan="6">ACTION TAKEN</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td>TIME</td><td colspan="2" rowspan="3">REMARKS</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td>TIME</td></tr>
<tr><td colspan="3">RESTORED SERVICE TO</td><td>TIME</td></tr>
<tr><td colspan="5">MATERIAL OR EQUIPMENT; CAUSE OF INTERRUPTION</td><td>CODES</td></tr>
<tr><td colspan="6">REVIEWED BY

Dispatcher   Superintendent   Engineer</td></tr>
</table>

Appendix 2

Interruption Report

INTERRUPTION REPORT					REPORT NO.		
DATE	TIME	RECEIVED BY					
LOCATION OR SWITCH NO.		REPORTED BY			TIME POWER WENT OFF		
SUBSTATION							
FEEDER		CAUSE					
DISTRICT		LOCATION OF CAUSE					
		ASSIGNED TO		TIME	TRUCK NO.		
ACTION TAKEN							
RESTORED SERVICE TO	DATE	TIME	NO. CUSTOMERS	CUSTOMER-MINUTES			
RESTORED SERVICE TO	DATE	TIME	NO. CUSTOMERS	CUSTOMER-MINUTES			
RESTORED SERVICE TO	DATE	TIME	NO. CUSTOMERS	CUSTOMER-MINUTES			
			TOTAL CUSTOMERS	TOTAL CUSTOMER-MINUTES			
MATERIAL OR EQUIPMENT				CODES			
				CAUSE	EQUIP	WEATHER	RUS FORM 7
REVIEWED BY							
Dispatcher		Superintendent			Engineer		

Appendix 3

Call Centers, SCADA, and IVR

Call Center

Call Centers have grown out of a need by cooperatives to handle larger call volumes with a person rather than a machine. The call center can either be staffed in-house by cooperative employees or outsourced to a call center at a different location. Due to economics or the desire to have high volume call handling capabilities with live customer service representatives out-sourcing may be the way to go for many cooperatives. In either case, the customer service representative will talk to the member gathering information needed to identify the member and the location of the interruption, including any other information the member may have about the interruption. The customer service representative may also be able to share information about the interruption with the member if they are already aware of the interruption. Call centers could then electronically forward this information to the appropriate operating personnel for dispatching and service restoration or as input to an interruption management system. In some cases, if properly equipped, the call center may actually dispatch the trouble ticket to the crew doing restoration.

Successful operation of a call center involves being sure the customer service representatives are trained to provide a positive image of the cooperative. The member should not be able to tell if the customer service representative (CSR) is a cooperative employee or an employee of an outsource call center. These CSRs should have fast reliable access to a customer database that will quickly provide account location and status (i.e., off for non-payment). This database should be updated at least daily. Theses CSRs should also have access to information concerning status of interruptions so they can keep members informed as the interruption progresses.

Interactive Voice Response Systems (IVR)

If a cooperative is willing to use advance call answering technologies they may want to investigate the use of an IVR system. These systems use electronic voice messaging to handle large call volumes fast and efficiently. These systems are especially attractive if the cooperative is using an automated interruption management system. Again, as in the call center application, these systems can either be implemented in-house or outsourced to third party vendors. Often this decision is based on a cooperative's ability to size their incoming phone lines to handle the phone traffic needed on large interruptions. For example, the existing cooperative capability may be only 12 – 24 incoming lines, while third party facilities may be capable of over 500 incoming lines. This increased call handling capability is especially critical if the cooperative is using an automated interruption management system. The cooperative may also consider using an emergency overload system where the calls go to the third party only after a set call volume is reached.

An IVR system works very similar to a call center except the customer is talking to a machine and not a live person. However, with advance speech recognition systems becoming more common, these systems are becoming more and more member friendly.

IVR systems require access to a current customer database giving account location and status (i.e. off for non-payment). Most IVR systems use member phone numbers for account recognition. This can be done using caller ID systems or by the member entering their phone number in response to a request from the IVR. Using phone numbers as account recognition requires cooperatives to be diligent in keeping phone numbers current for all accounts and in the case of multiple accounts the IVR system must have a method of distinguishing which account is actually out. This can be done by the IVR using text messaging of some account location field, which would uniquely identify the location to the member; or the IVR, using speech recognition, could ask the member to leave a message describing the proper location. If both of these methods failed the IVR could simply forward the member to a live person for resolution.

IVR systems also have the ability, when tied to an interruption management system, to give members feedback on interruption status and restoration time.

Appendix 4

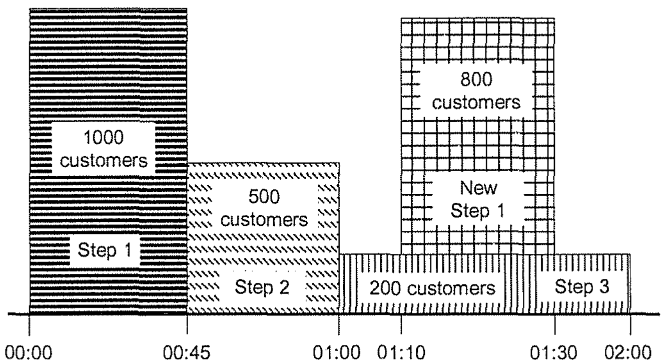
The Step Restoration Process and Example

The following case illustrates the step restoration process. A feeder serving 1,000 customers experiences a sustained interruption. Multiple restoration steps are required to restore service to all customers. The table shows the times of each step, a description and associated customer interruptions and minutes they were affected in a time line format.

Relative Time	Description	Customers	Duration (Minutes)	Customer-minutes of Interruption
00:00	1,000 customers interrupted.			
00:45	500 customers restored; 500 customers still out of service.	500	45	22,500
1:00	Additional 300 customers restored; 200 customers still out of service.	300	60	18,000
1:10	Feeder trips again, 800 previously restored customers interrupted again. (200 remained out and were not restored at this time.)			
1:30	800 customers restored again.	800	20	16,000
2:00	Final 200 customers restored. Event ends.	200	120	24,000
Totals:		1,800		80,500

Example SAIFI = 1,800/1,000 = 1.8 interruptions
Example CAIDI = 80,500/1,800 = 44.7 minutes
Example SAIDI = 80,500/1,000 = 80.5 minutes

The graph below shows the steps as they happened:



Appendix 5

Calculation of Major Event Days

The following process ("Beta Method") is used to identify major event days (MEDs). Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events. This approach supercedes previous major event definitions.

A major event day is a day in which the daily system SAIDI exceeds a threshold value, T_{MED}. The SAIDI index is used as the basis of this definition since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine the major event days, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins.

The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period as follows:

1. Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical date are available, use all available historical data until five years of historical data are available.
2. Only those days that have a positive SAIDI/Day value will be used to calculate the T_{MED}. Exclude the days that have no interruptions.
3. Take the natural logarithm, (ln) of each daily SAIDI value in the data set.

4. Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
5. Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
6. Compute the major event day threshold, T_{MED}, using the equation below.

$$T_{MED} = e^{(\alpha+2.5\beta)}$$

7. Any day with daily SAIDI greater than the threshold value T_{MED} that occurs during the subsequent reporting period is classified as a major event day.

4 Work Practices

In This Section: Work specifications; tree removal; tree pruning; incompatible target brush management; Integrated Vegetation Management; incompatible target brush species management technique selection; woody residue management

Work practices (Figure 4.1) are the methods and techniques used to maintain trees and control incompatible target brush species. Improper work practices can be costly, can increase regrowth rates following maintenance, can have negative impacts on vegetation health and aesthetics, and can detrimentally affect public relations. Proper work practices help to maximize the effectiveness of line clearance expenditures, minimize environmental impacts, and improve public relations. The consistent implementation of proper work practices is therefore essential when developing or maintaining a cost-effective vegetation management program.

The vegetation management techniques described in this section are recognized by the electric utility industry as the best management practices available for maintaining trees and controlling incompatible target brush species within the right-of-way (R/W) on an overhead electric system. Co-ops wishing to optimize the effectiveness of expenditures should ensure that vegetation management activities generally adhere to these best practices.

The implementation of proper work practices is essential to the long-term success of any co-op line clearance program. A co-op can help ensure that proper work practices are consistently implemented by including them in specifications that are tied to line clearance contracts. Periodic work evaluations will help to ensure compliance. Co-op management and supervisory personnel involved with a line clearance program should be thoroughly familiar with proper work practices and consistently enforce them systemwide.

4

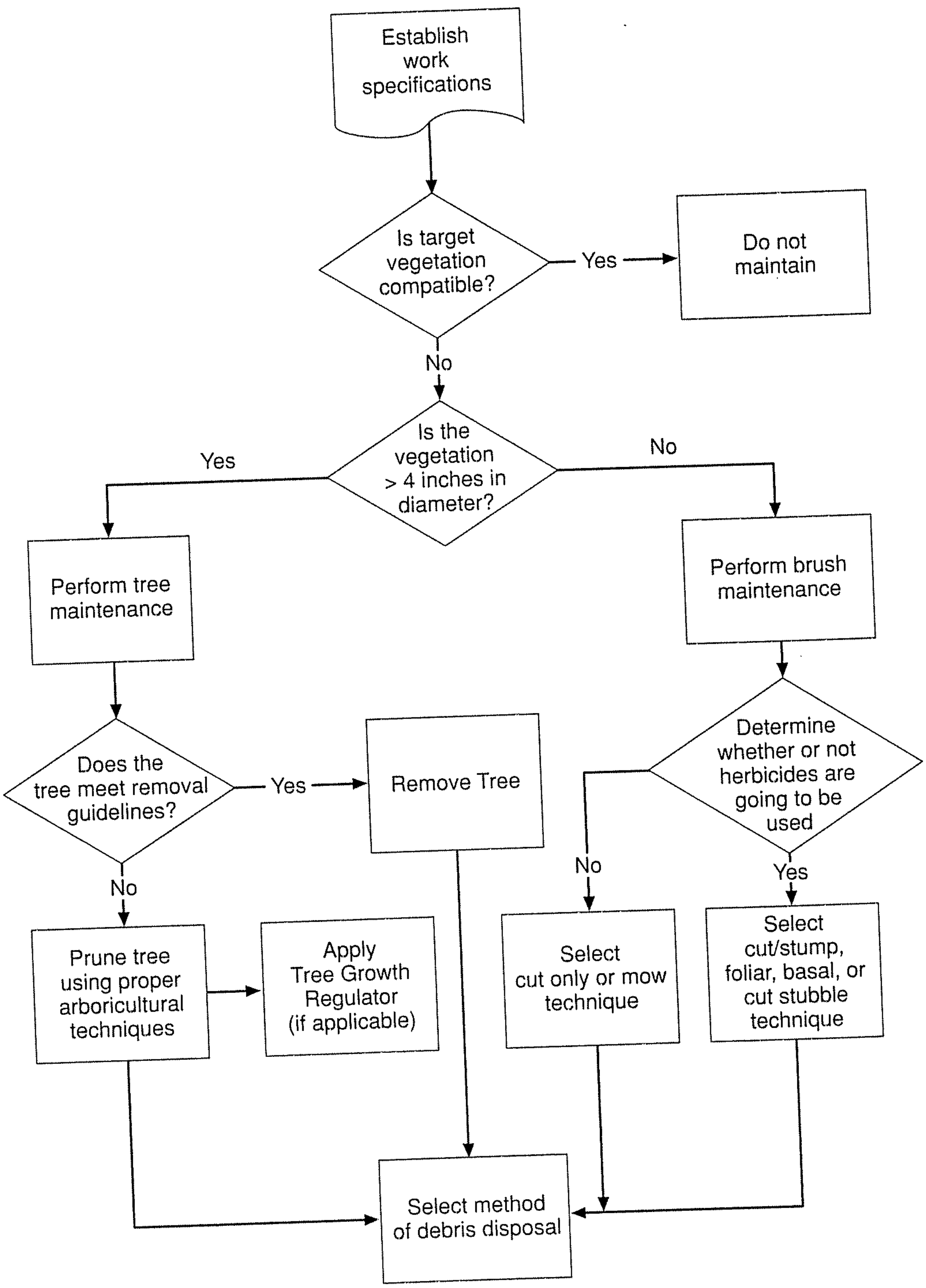


FIGURE 4.1: Work Practices Flowchart

4

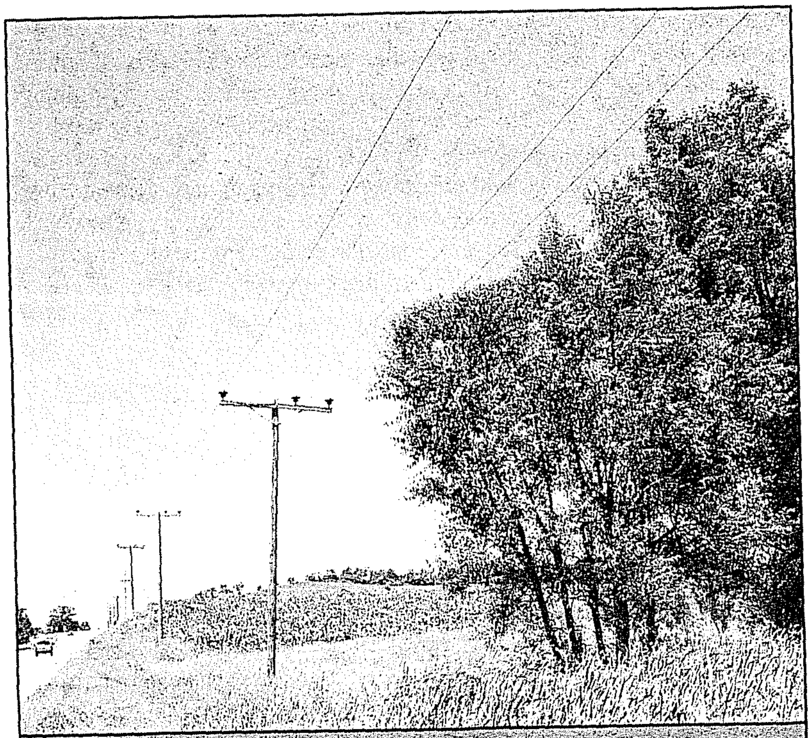


FIGURE 4.2: Removal Opportunities—Small-Diameter Trees in a Rural Area

THE ECONOMICS OF TREE REMOVAL

Electric utility data from across the United States consistently show that the cost to remove many trees is approximately equal to, and sometimes less than, the costs associated with pruning the same trees. Figure 4.3 shows typical utility data illustrating this point. The data also show that removal costs vary significantly in relation to tree size, so removal of large-diameter trees is not always cost-effective.

When evaluating removal candidates, a general 3 to 1 rule should be applied as an initial guideline. If a removal candidate would take more than 3 times longer to remove than to prune, it should be pruned. Otherwise, removal should be pursued. As a utility begins to accumulate cost and production data for trees on its system, these guidelines can be refined based on actual costs that are experienced and corporate goals for the line clearance program.

TREE REPLACEMENT

Utilities sometimes encounter resistance from property owners when tree removal is pursued, particularly when the removal candidate is an ornamental or landscape tree in an urban or residential area. Many utilities have found that a tree replacement program can be advantageous when seeking permission to remove troublesome trees. Utilities have also found that a tree replacement program can enhance their image as a good corporate neighbor.

To be cost-effective, replacement trees should not be offered on a one-to-one basis. Rather, a co-op should be selective when identifying candidates.

The most common and effective approach to implementing a tree replacement program is also one of the simplest. If negotiations with a property owner to remove a tree have failed, a voucher for the purchase of a replacement tree can then be offered in exchange for permission to remove the existing tree. The voucher can be

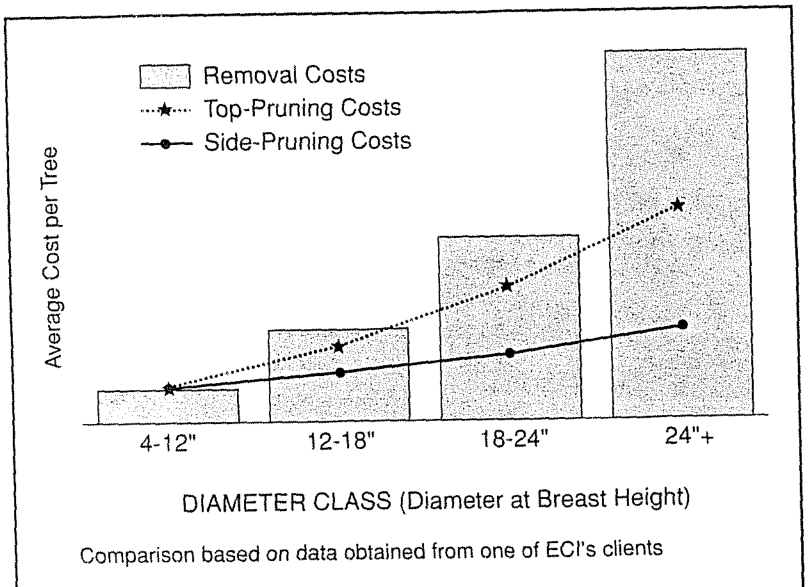


FIGURE 4.3: Comparison of Relative Pruning and Removal Costs

4

Work Specifications

Work specifications are a critical component of an effective vegetation management program. Without adequate work specifications, a co-op will have difficulty ensuring that proper work practices and operating procedures are being followed. Include detailed work specifications in all vegetation management contracts.

Proper work specifications should clearly state how all tree work and incompatible target brush control is to be completed. Vegetation management crews should adhere to the established specifications. Regular crew evaluations will guarantee that specifications are being followed.

Include clearance guidelines, proper pruning techniques, tree removal criteria, target brush species control techniques, and other effective work practices in vegetation management specifications. Appendix A contains a sample set of specifications that coincide with the recommended best management practices presented in this manual.

Tree Removal

Trees that grow in proximity to overhead electrical facilities must be pruned or removed to prevent interference with service reliability and to maintain system safety. As discussed in the Tree Pruning subsection, pruning is only a temporary measure. Removal provides permanent clearance if a herbicide is applied to the surface of the freshly cut stump.

> Simply removing a tree will not necessarily result in permanent clearance. If the stump of the tree is not treated with a herbicide, the tree may resprout and continue to be a part of the vegetation workload. This situation typically applies only to deciduous species. Even though some coniferous species have the ability to produce sprouts from the cut stumps of juvenile trees, this capability is limited. Therefore, it is usually unnecessary to apply a herbicide to the stump surface of removed coniferous species.

Tree removal, in conjunction with a selective herbicide application to prevent sprouting, will provide both short- and long-term benefits. An aggressive tree removal program is an integral component of an effective line clearance program.

Tree removal is the only way to reduce or maintain the size of the existing vegetation workload. In fact, many utilities have found that, if they are not removing approximately 10% to 20% of the total tree workload each maintenance cycle, the tree workload expands and maintenance costs increase. An aggressive tree removal program is crucial to preventing continual expansion of the tree workload and controlling long-term costs.

There are two common misconceptions in the utility vegetation management industry regarding tree removal:

1. It costs too much to remove trees, and removal should be avoided.
2. As many trees as possible should be removed, regardless of their size or location.

Both of these extreme approaches are incorrect and point out the need to develop flexible, yet specific, tree removal guidelines.

In general, electric co-ops should concentrate tree removal efforts on fast-growing, small-diameter trees located beneath conductors in rural areas (Figure 4.2). Landscape and ornamental trees located in urban or residential areas are usually not good removal candidates unless an evaluation determines that removal would be beneficial. If a tree is dead, dying, diseased, or structurally unsound and poses an imminent hazard to electrical facilities, it should be pruned to eliminate the hazard or removed regardless of its size or location.

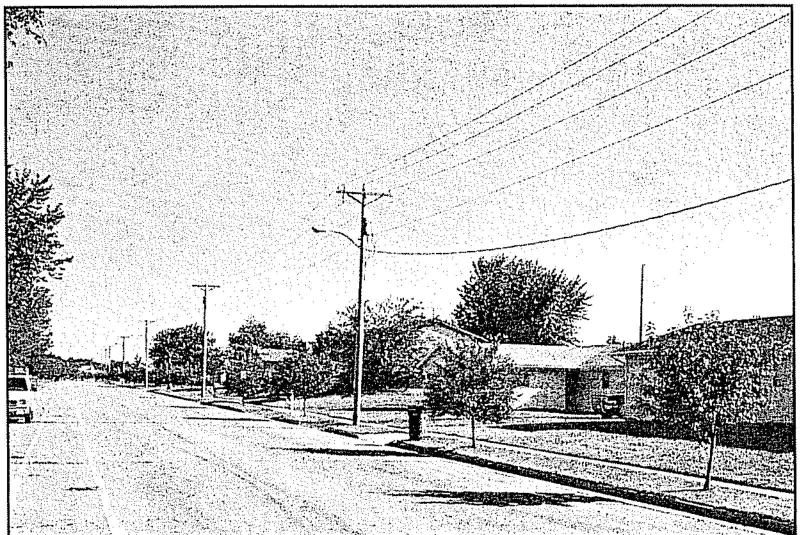


FIGURE 4.4: Compatible Low-Growing Trees Planted Beneath Three-Phase

redeemed at a local nursery, and the property owner is then responsible for planting and maintaining the tree.

To make certain that replacement trees will not eventually threaten system integrity or safety, replacement tree programs should be regulated to include only those species that will not grow too tall and ultimately come into contact with overhead electrical facilities. Figure 4.4 shows examples of compatible trees planted beneath overhead lines.

Appendix B contains a list of some common species that are suitable for planting beneath overhead utility lines. Co-ops should consult with local tree boards, area university extension services, and local nurseries when developing a list of tree species that are compatible with overhead wires.

An excellent reference guide for tree species that are compatible with overhead electrical facilities throughout most of the United States is *Compatible Tree Factsheets for Electric Lines and Restricted Spaces*. This book contains pictures of and data for trees whose mature size will not interfere with overhead lines. For more information contact The Pennsylvania State University Publications Office, 112 Agricultural Administration Building, University Park, PA 16802.

Tree Pruning

Pruning refers to the use of widely recognized, proper arboricultural techniques to remove limbs or branches from a tree. Trimming is the use of incorrect techniques to achieve the same goal.

The majority of the trees on an electric co-op's distribution system will typically require periodic pruning to maintain adequate clearance from overhead electrical facilities. Pruning is an ongoing, temporary method of controlling or maintaining tree growth.

The primary goal when pruning trees should be to establish adequate clearance between tree limbs and overhead electrical facilities, which minimizes potential impacts on system reliability and safety. Secondary goals should be to maximize the length of time between prunings and to minimize impacts to tree health and appearance. These secondary goals can be accomplished by implementing proper pruning techniques (Figures 4.5, 4.6, and 4.7).

Proper pruning techniques can direct growth away from the conductors by taking advantage of a tree's natural growth tendencies. Studies have documented that properly pruned trees grow toward the conductors at a rate that is 25% to 50% slower than improperly trimmed trees (Figures 4.8, 4.9, and 4.10). Proper pruning makes good economic sense because it extends the control period between maintenance activities.

Proper pruning techniques also allow a tree's natural defense mechanisms to function and react to the stresses of pruning. Branches that have been properly pruned back to a suitable parent limb or the main trunk also look more natural than leaving unsightly stubbed branches throughout the crown of a tree.

TIPS *Most coniferous trees are not capable of resprouting when branches are properly pruned back to the main trunk. Some southern pine species will produce regrowth following pruning, but the growth is usually limited and largely dependent on environmental factors. Therefore, conifers that are properly side pruned back to the main trunk typically do not require maintenance in the future, which results in long-term cost savings.*

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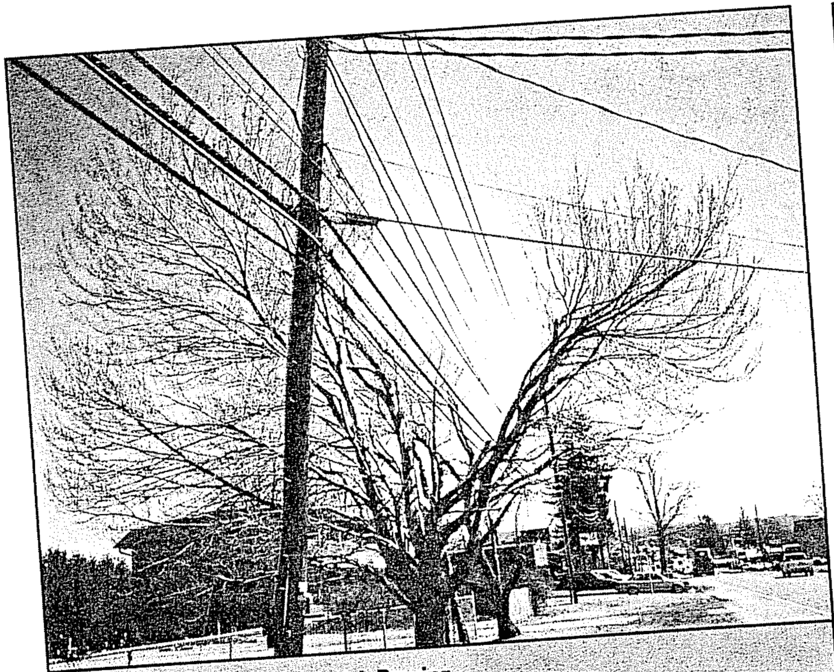

FIGURE 4.5: Proper Drop Crotch Pruning

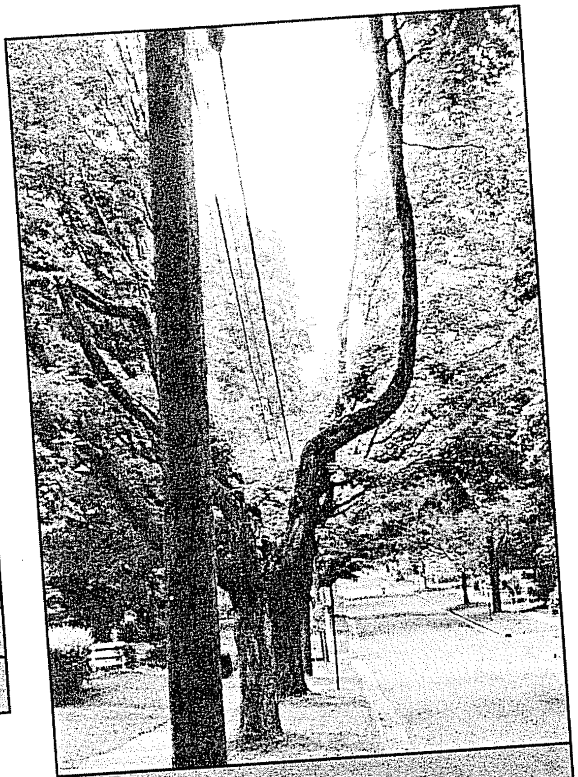

FIGURE 4.7: Proper Top Pruning

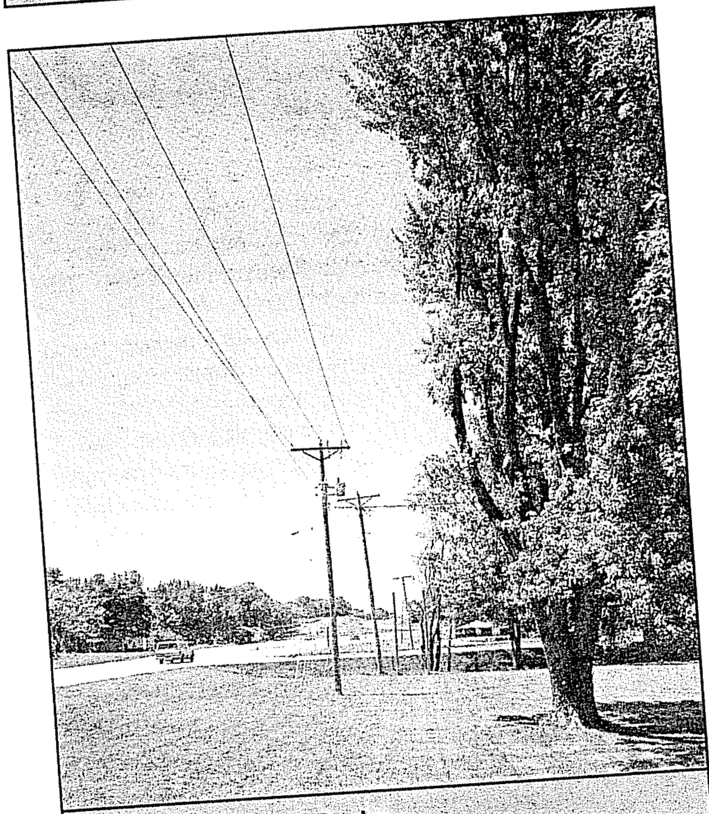

FIGURE 4.6: Proper Side Pruning

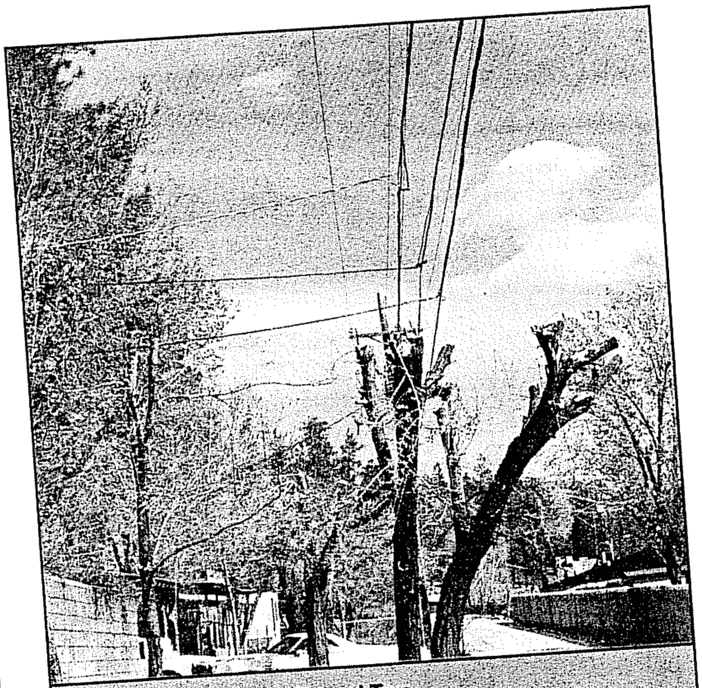

FIGURE 4.8: Improperly Topped Tree

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FIGURE 4.9: Improper Trimming

FIGURE 4.10: Improper Trimming—Stubbed Branches

Electric co-op tree pruning should generally adhere to American National Standards Institute (ANSI) Std. A300[1] or Dr. Alex Shigo's booklet titled *Pruning Trees Near Electric Utility Lines*.[2] Both publications present what are recognized by the utility line clearance industry as best management practices for utility tree pruning.

These standards provide limits and criteria for proper arboricultural work. However, ideal pruning techniques may not always be compatible with a co-op's primary goal of providing safe and reliable clearance, and variations may be necessary when pruning individual trees. Appendix C provides additional information on the application of proper pruning techniques to specific co-op tree conditions.

If trees on an electric co-op's distribution system have been improperly trimmed in the past, making a change to proper pruning techniques will require considerable effort, and training will likely be necessary. All crews completing line clearance work should be required to adhere to a common set of specifications that include proper pruning practices. Periodic evaluations of work that has been completed will help to ensure proper techniques are being used. Co-op personnel responsible for supervising line clearance work should have a complete understanding of proper pruning practices so they can effectively evaluate work that has been completed.

Co-ops may also encounter opposition from property owners and the public when a change in pruning techniques occurs. Many people become used to seeing trees maintained in a certain way, whether it is through the use of proper pruning or improper trimming techniques, and they may not understand why trees suddenly look different. An ongoing public relations effort may be necessary to keep the public informed of the benefits of proper pruning techniques.

[1]Available from American National Standards Institute, 11 West 42nd Street, New York, NY 10036

[2]Available from Shigo and Trees, Associates, 4 Denbow Road, Durham, NH 03824

The application of a wound dressing or pruning paint to fresh pruning cuts is generally not necessary. Research has shown that wound dressings do not eliminate most insect, disease, or rot problems as was previously thought. On the other hand, studies have also shown that pruning paint can help prevent the occurrence of oak wilt infection and, in some states where oak wilt is a problem, utilities are required to use wound dressings when pruning oaks at certain times of the year.

In general, co-ops should refrain from using wound dressings during line clearance operations unless it is required for cosmetic purposes to make fresh pruning cuts less noticeable.

A tree located beneath conductors that has been rounded over or topped in the past is often very difficult to prune properly. In such cases, removal of the tree is often the most arboriculturally sound option.

Don't top trees! Tree topping is the practice of uniformly cutting back the crown of a tree to achieve clearance. It was a common method of trimming trees beneath utility lines years ago and can still be observed on many systems today. Topping results in numerous stubbed branches that produce rapid, weakly attached regrowth. Topping disfigures trees and makes them highly susceptible to decay, disease, and other health problems.

Many communities, particularly those that are associated with the National Arbor Day Foundation's Tree City USA program, have implemented ordinances that prohibit the topping of trees. All electric co-ops should work toward the elimination of this highly destructive and improper trimming technique on their systems.

Incompatible Target Brush Management

The electric utility vegetation management industry typically defines trees as species with woody stems greater than 4 inches diameter at breast height (4.5 feet above ground) that mature at heights greater than 20 feet. Immature tree stems (woody species less than 4 inches diameter at breast height and with the capability to exceed 20 feet in height) are defined as incompatible target brush for the purposes of this manual.

It should be clearly understood that not all low-height vegetation on a R/W will eventually mature and pose a threat to overhead electrical facilities. Small trees with low mature heights (Figure 4.11), shrubs, grasses, etc., are considered to be compatible with overhead electrical facilities. It is neither cost-effective nor beneficial to the environment to control this vegetation. Compatible, low-growing vegetation can also help to reduce the

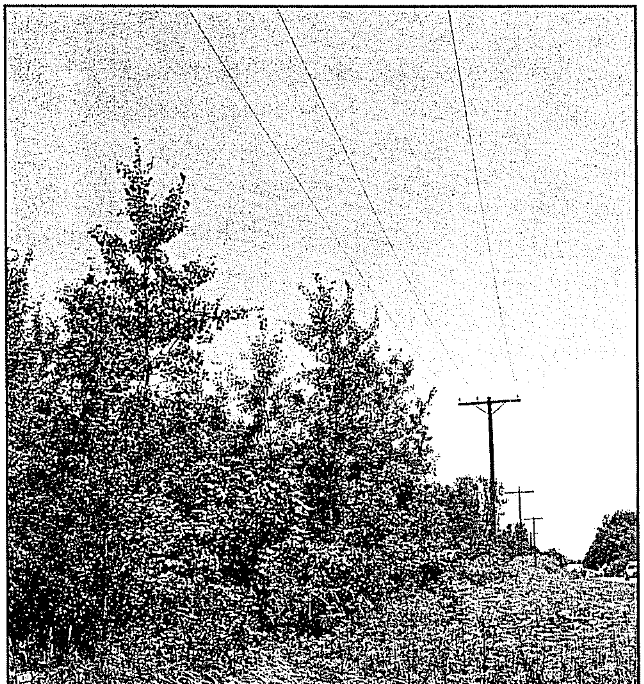

FIGURE 4.11: Brush Maturing

occurrence of tall-growing species (Figure 4.12), which helps to reduce vegetation management costs. Compatible vegetation should therefore be retained and encouraged as much as possible.

Immature trees (target brush) are a component of the vegetation workload that is sometimes overlooked because they typically do not pose an immediate threat to system reliability or safety. However, ignoring incompatible target brush and allowing it to mature can increase maintenance costs, impede or prevent accessibility to facilities, and result in a significant increase to the tree workload as it matures. Incompatible target brush species can also threaten system reliability and safety as they mature and reach conductor heights.

Aggressive incompatible target brush species control is crucial in preventing future expansion of a co-op's vegetation workload and future cost increases. The methods used to control incompatible target brush also have an impact on cost-effectiveness. Since target brush conditions, geography, terrain, and demographics all vary within a given co-op's service area, a variety of methods should be implemented to control incompatible target brush species.

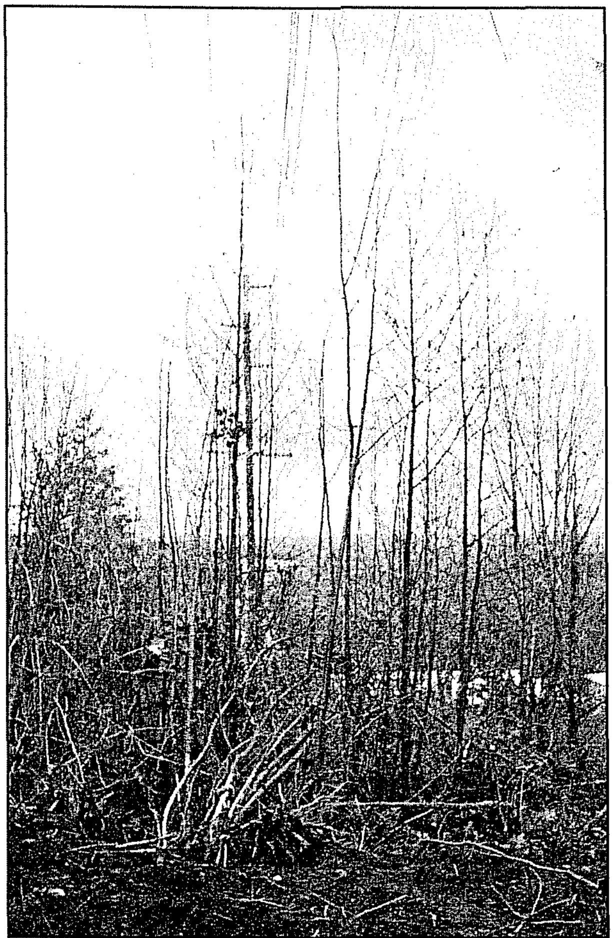

FIGURE 4.12: Tall Brush

Integrated Vegetation Management

Integrated Vegetation Management (IVM) is a pest control concept borrowed from Integrated Pest Management (IPM) that considers biological, chemical, cultural, and physical (e.g., mechanical and manual) methods to control undesirable vegetation. The method that is implemented to control undesirable vegetation at any given location is selected on the basis of treatment effectiveness, site characteristics, environmental impacts (including impacts to desirable, non-target vegetation species), safety, and economics. Flexibility is a key aspect of IVM.

Properly implemented, IVM is recognized as a methodology that encompasses a range of industry-established best practices. It is therefore an integral component of an effective vegetation management program.

In general, physical or chemical control methods are the most appropriate incompatible target brush control options for a given electric system. Biological controls (e.g., grazing by animals) and cultural controls (e.g., using fire to eliminate undesirable vegetation) have extremely limited application and are seldom used as utility vegetation maintenance techniques. However, the retention of low-growing, compatible vegetation on the R/W (Figure 4.13) will inhibit the future growth of incompatible species and is therefore considered a form of biological control.

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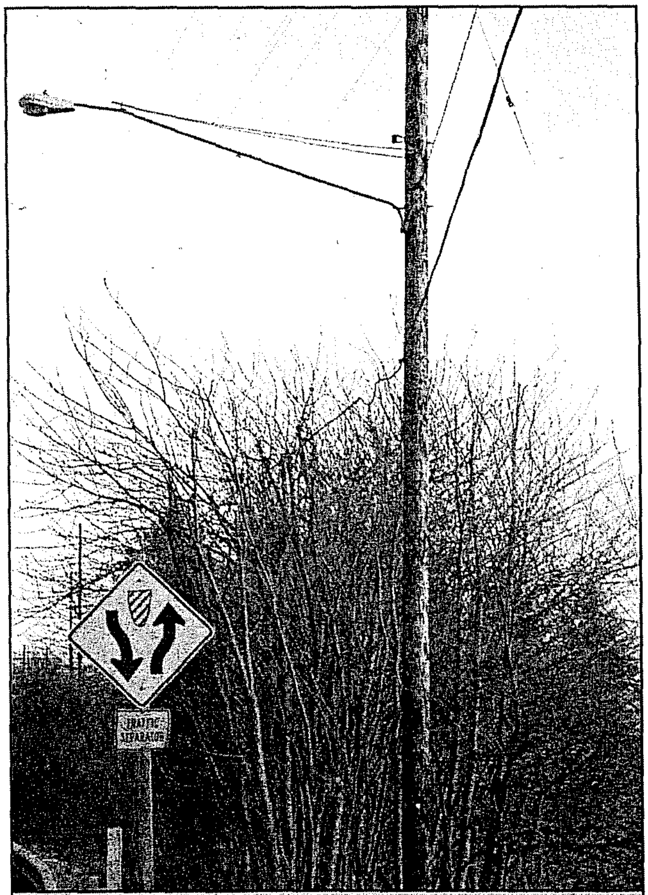


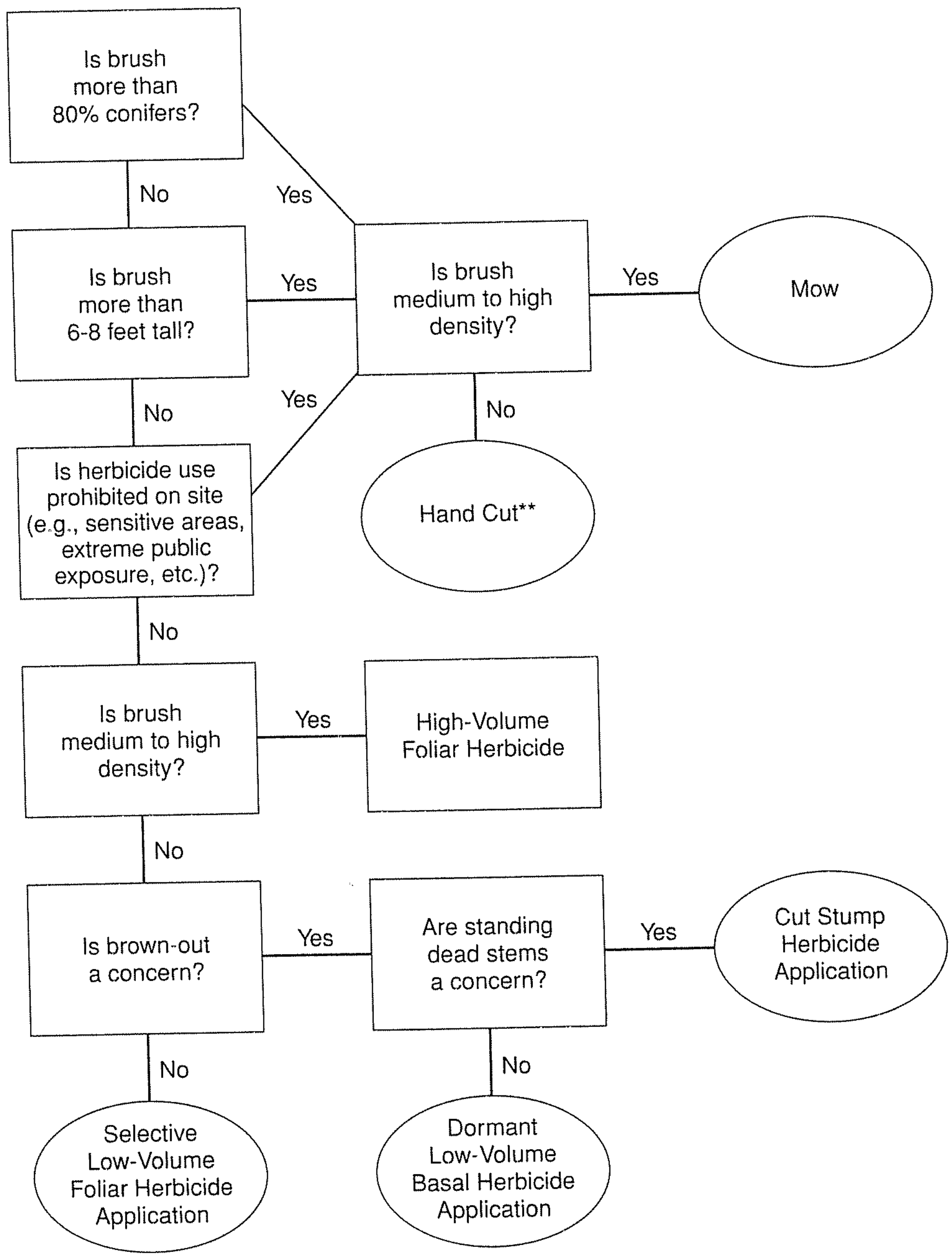
FIGURE 4.13: Trimmed Brush

Incompatible Target Brush Species Management Technique Selection

At any given site, the method selected to control incompatible target brush species has a direct impact on the vegetation communities that result following maintenance. In general, non-herbicide physical maintenance techniques (e.g., hand cutting and mowing) will encourage the proliferation of incompatible broadleaf brush species through stump sprouting, and in some species root suckering, thus creating a worse incompatible target brush problem than previously existed prior to the treatment. The use of herbicides will reduce stem densities of incompatible target species and provide long-term control of vegetation, thus reducing long-term maintenance expenditures.

The selection of an incompatible target brush species maintenance technique for a given area will be dictated by a number of factors. Target brush height and density will be the most important criteria in determining the appropriate control technique to employ. Additional factors that help determine an appropriate control method are terrain conditions, density of low-growing compatible vegetation, restrictions to maintenance practices (e.g., land use or public sensitivity), and the availability of expertise to successfully implement and monitor certain control methods such as specialized herbicide applications.

Figure 4.14 will assist in developing initial incompatible target brush management prescriptions on the basis of general site conditions. The flowchart provides an indication of the complexities that are involved in selecting appropriate target species control methods.



*This flowchart is a general guideline for prescribing an appropriate brush control treatment for a specific right-of-way site, but adequate training and experience are essential for successful implementation.

**If herbicide use is permitted on the site, cut stumps of deciduous trees could be treated with herbicide to control sprouting.

FIGURE 4.14: Decision Flowchart for Prescribing Brush Control Treatments*

The chart is not intended to replace the expertise and experience that should be provided by vegetation management professionals. Co-ops should retain in-house staff with vegetation management expertise and/or consult with vegetation management contractors, consultants, and chemical company representatives before proceeding with implementing sophisticated IVM strategies to control vegetation.

A professional approach and sufficient technical expertise are particularly critical when implementing a program that includes herbicide applications. A successful IVM program and general public acceptance of herbicide use will depend on an electric co-op's commitment to a coordinated and professional effort to ensure the protection of both human health and the environment.

HAND CUTTING

Hand cutting uses a chain saw or brush saw to remove undesirable target vegetation. Hand cutting (Figure 4.15) is the preferred maintenance technique for sites where obstacles (e.g., rocks, poles, or tower bases) exist or terrain conditions prevent access by mowing equipment and where herbicides cannot be used.

Hand cutting results in the immediate elimination of the above-ground portion of undesirable target species. Compatible low-growing species are typically retained with this method, and a high level of selectivity can be achieved.

Unfortunately, hand cutting only affects the above-ground portion of the vegetation that is being maintained. The root collar area of the cut vegetation remains intact and viable, and hand cutting typically results in vigorous stump sprouting (Figure 4.16) and, in some species, root suckering as well.

The rapid growth and multiple stems that typically follow hand cutting (Figure 4.17) can increase incompatible target species stem densities significantly, resulting in a worse target species problem than previously existed. The control provided by hand cutting is short term, and the use of this technique alone should be limited. Long-term control of target species that have the capability of resprouting can only be achieved by applying a herbicide to the surface of the cut stump immediately following cutting (see cut stump subsection on page 29).

FIGURE 4.15: Hand Cutting Brush

When hand cutting target vegetation, stems should be cut as close to the ground as possible, and stump heights should typically not exceed 3 inches. Cuts should not be made on an angle, which results in pointed stumps that can be hazardous to humans, animals, and equipment.

Hand cutting can be performed at any site that is accessible to workers. This technique can be employed at any time of the year except when deep snow prevents cutting close to ground level.

Hand cutting should generally be limited to sites where target species stem densities are light to moderate and mowing is not economically feasible, and in areas where it is preferable to control incompatible target stems by cutting them at ground level.

FIGURE 4.16: Resprouting Stump (Cut Without Follow-Up Herbicide Treatment)

FIGURE 4.17: Regrowth/Sprouting from Removed Tree

MOWING

Mowing consists of mechanically cutting incompatible target species with a large cutting machine attached to a tracked or rubber-tired vehicle. See Figure 4.18. Although there are numerous sizes and configurations of mowing equipment available, cutting heads for utility vegetation maintenance generally fall into two categories: rotary cutting heads and flail-type.

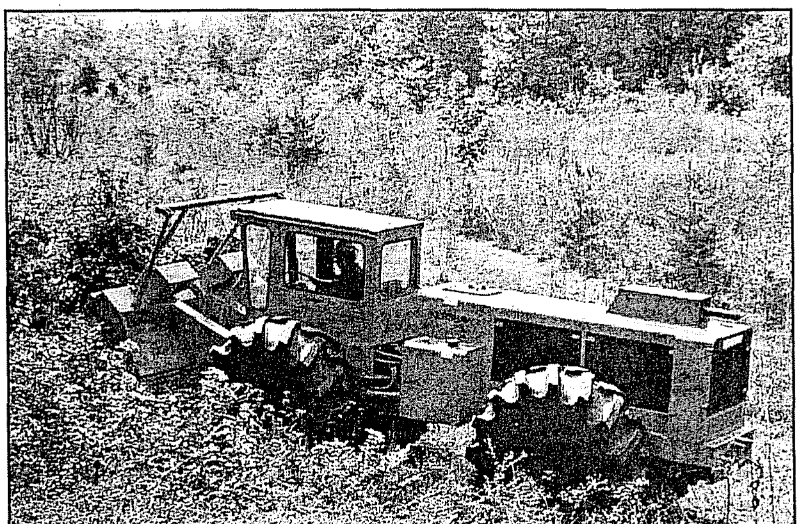


FIGURE 4.18: Mowing Brush

Rotary cutting heads consist of one or more blades that rotate horizontally, cutting and shredding vegetation. Flail-type mowers consist of metal teeth or chains attached to a rotating drum, which knocks down and shreds vegetation. Rotary style mowers are typically referred to as "brush hogs" and flail-type mowers are generally classified as "hydro-axes."

Depending on the size of the mowing equipment being used and the target species being managed, vegetation up to about 8 inches in diameter can reasonably be cut. Some specialty vegetation management equipment can even handle larger diameter vegetation.

As with hand cutting, mowing results in the immediate elimination of all undesirable target stems. However, since this technique is not selective, all desirable low-growing vegetation within the mower's path is eliminated as well. Thus, the site is left in a disturbed and more open state, which allows tree seeds to germinate in addition to encouraging stump sprouting.

Mowing will not provide long-term control of communities of target species unless followed up with a herbicide application to control resprouting. (See Herbicide Treatments below for a discussion on mowing with a follow-up herbicide application.)

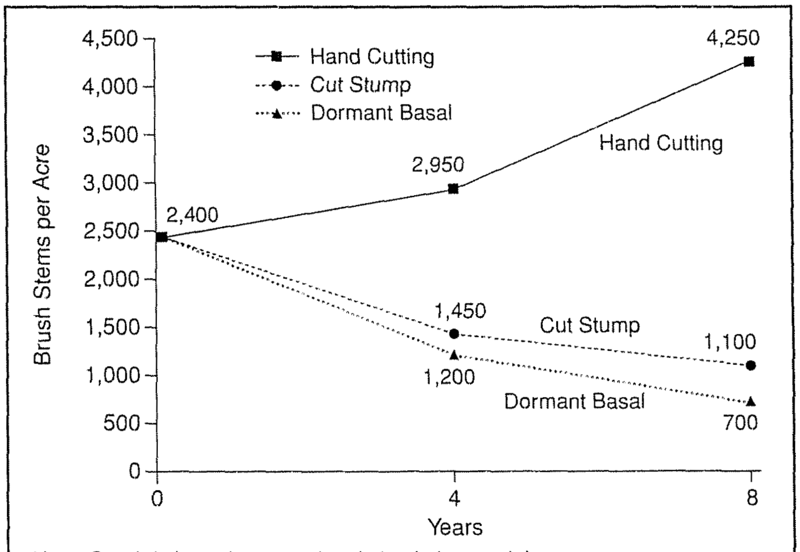
Mowing is the recommended maintenance technique for relatively flat areas with few obstacles (e.g., rock outcroppings, boulders, and stone walls), areas that support moderate to heavy densities of incompatible target species, and locations where herbicides cannot be used. As long as the site is accessible to mowing equipment, mowing will typically be more cost-effective and practical than hand cutting. This is particularly so when areas have been repeatedly mowed over several maintenance cycles and incompatible species densities have increased significantly.

Mowing can be done at any time of the year as long as sites are accessible. The only difficulties that may prevent mowing are steep slopes, debris on the easement or R/W, and rocky terrain. Mowing is also typically unacceptable on wet sites since heavy equipment can result in significant soil disruption, and soft, wet soil conditions can impede or even prohibit the progress of machinery along the R/W.

HERBICIDE TREATMENTS

The routine selective use of herbicides to control undesirable vegetation on electric co-op systems is essential to reducing long-term costs and to maximizing the benefits of both tree and incompatible target brush species removal programs. Judicious herbicide use is an important component of an IVM strategy, and it is critical to the establishment of a low-growing plant community on the R/W that results in a cost-effective vegetation management program.

The effectiveness of selective herbicide applications has been well documented by the electric utility vegetation management industry. Selective herbicide applications control unwanted, tall-growing target vegetation and encourage retention and expansion of desirable plant communities. Once these low-growing, desirable plant communities become well established, the occurrence of non-compatible tree stems decreases and future maintenance costs are reduced (Figure 4.19).



Note: Graph is based on a regional simulation model.

FIGURE 4.19: Effectiveness of Selective Herbicide Treatments for Brush Control

The establishment of communities of low-growing, compatible vegetation should be a primary goal of a utility target brush species control program. As progress is made toward achieving this goal, the inputs required to control undesirable vegetation can be reduced over time. The inputs required to manage vegetation can be described as herbicides (including adjuvants and carriers), labor, and equipment. Incentives to reduce the inputs are found in:

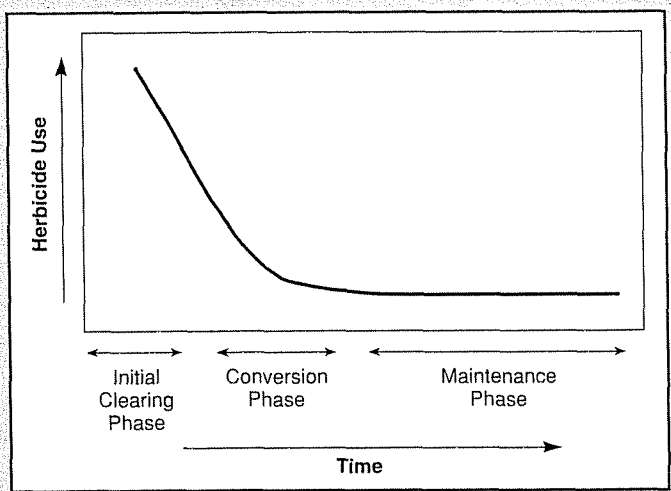
- Reducing environmental load
- Reducing costs

There are two concepts to consider when practicing vegetation management through the selective use of herbicides on an electric co-op system:

1. Selectivity for desirable vegetation based on *herbicide selection*. Herbicides are selected that predominantly control the undesirable target vegetation while leaving some compatible low-growing desirable vegetation (e.g., grasses) unaffected.
2. Selectivity for desirable vegetation based on *application technique*. Herbicides are directed vs. broadcast through specific application to the undesirable tall-growing target vegetation. Desirable low-growing vegetation does not receive treatment and is retained on the R/W.

To gain control of a R/W filled with undesirable vegetation, an initial clearing or "reclamation" treatment phase is typically required. Vegetation conditions are assessed and the appropriate herbicide and application technique are chosen. Generally, initial clearing is performed through the broadcast application of a herbicide on all heavy-density, incompatible target brush species that typically exhibit various stages of height growth, depending on the time elapsed since the last mowing or hand cutting treatments were performed. In this phase, the vegetation in the target area is predominately undesirable, and a herbicide is applied to achieve coverage of all target stems within the entire R/W area to be managed.

Once the initial vegetation clearing phase has been completed and undesirable stem densities have been reduced, the amount of labor and herbicide required to maintain a site drops sharply (but is never eliminated into a "maintenance-free" situation).



Removal of incompatible target species through herbicide applications will promote a low-growing plant cover of shrubs and herbs (grasses and forbs) that helps to resist the establishment of tall-growing, undesirable tree species. The conversion of a R/W to this state depends on the amount of desirable vegetation present at the time of the initial reclamation phase. Achievement of the minimum maintenance phase should require no more than two additional applications (4 to 7 years apart), and in some cases only one more treatment will be required. Each subsequent application in the ensuing and minimum maintenance phases uses less herbicide, labor, and fuel since less undesirable target vegetation is present. The reductions in the amount of chemicals used, in the labor required, and in the type and amount of equipment needed to maintain desirable vegetation on the R/W and control target species can translate into significant cost savings for a vegetation management program.

Herbicide applications in later phases are specifically targeted at the undesirable tree species by directed applications. Tremendous selectivity (both with herbicides used and application techniques employed) can be achieved once this phase is reached. Efforts in these later treatment cycles emphasize minimum disturbance to the desirable, low-growing vegetation so as to promote and sustain its continued presence on the R/W.

Herbicide applications should be an integral part of a co-op's IVM strategy. An important consideration is that herbicide use must be environmentally compatible and professionally supervised in order to achieve and maintain public acceptance. Crews who have received training in species identification, handling of herbicides, and application methods should complete all herbicide applications. Follow all applicable pesticide laws regulating herbicide use.

Appendix D contains examples of herbicides that are suitable for electric utility vegetation management. This appendix also includes information on tank mixtures and additives.

Crew personnel completing herbicide applications have significant responsibility to ensure that herbicides are handled and applied correctly. However, co-op management personnel should have the ultimate responsibility for making sure that the overall vegetation management program, including the use of herbicides, is safe, professional, and effective.

The techniques used for herbicide application can be divided into two broad categories: directed (or selective) and broadcast. Directed, as implied, describes an application that is applied only to target stems. The amount of herbicide mix that is applied varies and depends on the density and height of target stems that are to be controlled. Broadcast applications are set at a fixed rate per area and, once fixed, are independent of the density of the target stems that are to be controlled. Within these two application categories, specific application techniques can be defined as follows:

- Broadcast
  - Foliar
  - Cut stubble
- Directed (selective)
  - Foliar (high-volume and low-volume backpack treatments)
  - Basal bark (low-volume treatment)
  - Cut surface (stump treatment)

Broadcast Foliar Application

Broadcast foliar applications are applied to the foliage of target tree species during the period of active growth when leaves are fully developed (late spring to early fall). A fixed herbicide rate per area is applied in a water solution and broadcast over the entire target area. Liquid volumes of mixture, which are predetermined, typically are in the area of 20 or more gallons per acre. Tall, high-density target tree species should generally be treated using higher volumes of solution to help ensure that the mixture penetrates all of the canopy layers. A common method for completing broadcast foliar herbicide applications uses a Radiarc® spray device (or similar boom equipment) that is mounted on a tractor or other vehicle suitable for traversing the R/W or easement.

Broadcast foliar herbicide applications are sometimes the most cost-effective way of initially controlling heavy-density communities of tall-growing target tree species, particularly over large areas. Once an initial broadcast application has been made, stem densities of target vegetation will be reduced, and subsequent maintenance should employ selective treatment methods.

Although broadcast foliar applications can be applied to target tree stems of any height, 15 feet is usually a good limiting height. However, more chemical will be needed to control taller target trees. Also, extremely tall target trees that die following treatment and remain standing on the R/W can be aesthetically unpleasing.

Since this technique will result the complete brownout of R/W vegetation, it is best suited for rural areas well away from the view of the general public. In general, broadcast foliar applications should be made to vegetation that is less than 6 to 8 feet high.

Cut Stubble Applications

When a reclamation phase is necessary and the moderate to high-density vegetation is too tall to initially implement a broadcast herbicide application, the site should first be mowed before herbicides are applied. A herbicide can be applied via a broadcast foliar application one or two growing seasons following mowing to vegetation that has resprouted. An alternative is to immediately follow mowing with a broadcast application of a soil-active herbicide, which prevents resprouting altogether. This technique, known as a cut stubble application (Figure 4.20), can be employed in more visually sensitive areas since treated vegetation has minimal leaf-out and brownout is substantially reduced.

This maintenance technique is subject to the same limitations described for mowing and broadcast foliar herbicide applications. The cut stubble technique is not selective, meaning that many desirable species are usually eliminated with this treatment method. Depending on the herbicide formulation used, some selectivity for grasses can be achieved.

High-Volume Foliar

High-volume foliar is an application technique that typically utilizes a maneuverable vehicle (such as a truck or tractor) equipped with a large spray tank (Figure 4.21). Herbicide applications are applied to the foliage of target tree species using a hand-held, high-volume spray gun. Maximum effectiveness is generally achieved when target tree heights are between 8 and 15 feet.

The concentration of herbicide used for this technique is low and typically ranges from ½% to 1½% of the spray solution. Volumes of spray

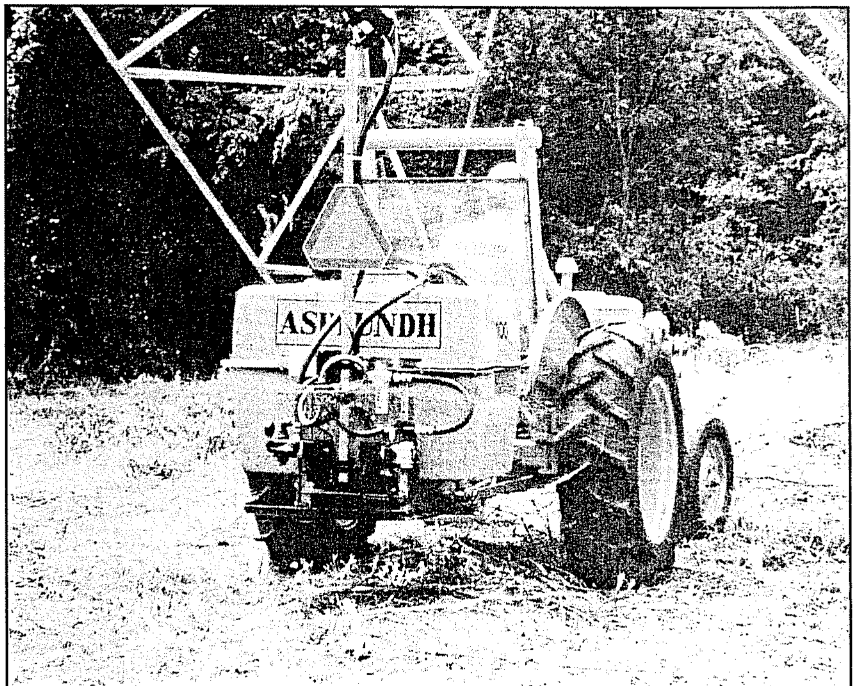


FIGURE 4.20: Cut Stubble Treatment (Broadcast Herbicide Application Following Mowing)

FIGURE 4.21: High-Volume Foliar Herbicide Application

mixture used will vary depending on vegetation conditions, but will typically range from 100 to 400 gallons of spray solution per acre.

High-volume foliar applications apply herbicide to target species 8 to 15 feet tall and of medium to high density by thoroughly wetting all of the leaves and the stem. Operator skill is essential to achieving some selectivity with this technique. Spray pressure at the tip should be the minimum required to obtain plant coverage. The spray should be directed no higher than the target tree being treated. The use of a thickening agent or drift control additive is advisable to avoid the production of fine particles that may drift onto sensitive non-target plants. Nozzle tips that produce coarse droplets of solution should be used to help reduce drift.

High-volume foliar applications should be performed during the period of active growth and when leaves are fully formed (generally from late spring to early fall). This technique can be performed on any site as long as terrain conditions permit access by spray vehicles.

When treating a R/W that has a high density of target species, the difference in results between selective high-volume foliar and uniform broadcast applications will often be minimal. The vast majority of plant materials on the R/W should be target species if either of these application techniques is used, which will result in a R/W with a browned-out appearance.

Low-Volume Foliar

This method of application uses a higher concentration of herbicide (3% to 10%) than the high-volume technique. The selectivity of the low-volume foliar spray technique is achieved through the close application of coarse sprays that are directed at individual stems or clumps of non-compatible target species while directing the spray away from compatible vegetation (Figure 4.22).

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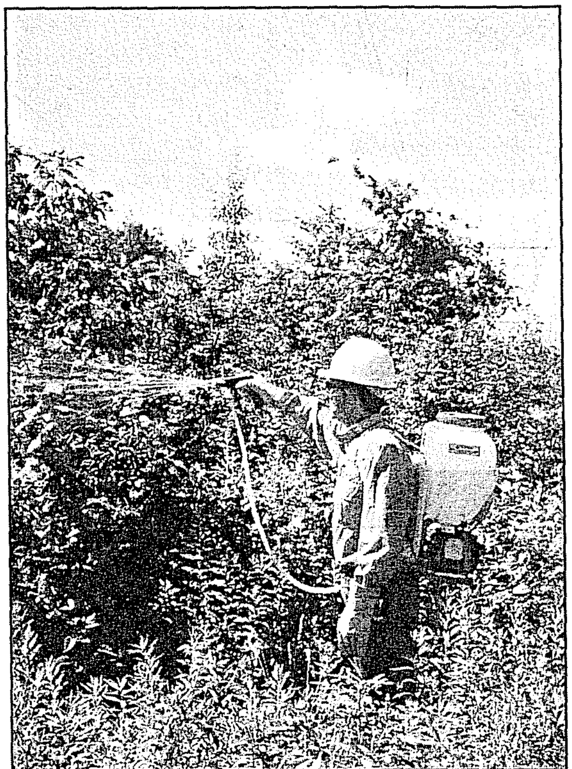

FIGURE 4.22: Low-Volume Foliar Herbicide Application

Low-volume applications are generally targeted at incompatible stems that are less than 6 to 8 feet high and of low to moderate density. A conventional diaphragm or piston pump backpack is the most commonly used piece of equipment for low-volume applications, but small-volume battery-operated tanks on ATVs have also been used effectively.

A spray wand can be used to deliver the herbicide solution. However, many applicators have found that equipment similar to the Dual Spray Gunjet® (DSG) offers more versatility. The DSG can be used with a conventional backpack or with the ATV. The DSG allows the applicator to switch between nozzles for the selection of a wide pattern for short spray distances or a narrow pattern for longer distances. Interchangeable nozzles increase the flexibility of this application technique.

Low-volume foliar applications are directed at the top of the crown of target stems, and the upper 60% to 75% of the crown typically receives treatment. Application is made to wet the leaves, but not to the point of runoff. As with other foliar application techniques, low-volume applications should be done during the period of active growth, when leaves are fully developed.

Low-Volume Basal Bark

Low-volume basal herbicide applications (Figure 4.23) offer increased flexibility over foliar applications. Basal applications can be performed during the dormant season, as well as during the period of active growth. Dormant season applications allow crews to be productive during the off-season and can be advantageous in some locations where the brownout associated with foliar applications may be objectionable. This is a very selective application technique.

Basal applications control undesirable vegetation through the application of a herbicide and penetrating oil mixture to the lower 12 to 15 inches of target stems. The mixture typically

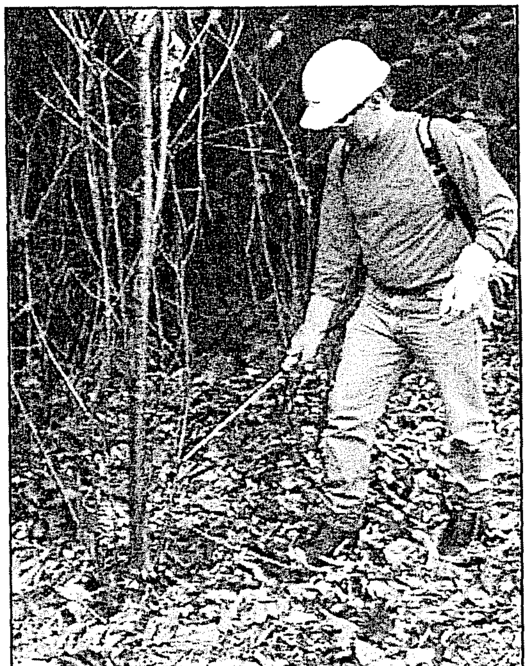

FIGURE 4.23: Low-Volume Basal Herbicide Application

contains a relatively high proportion of herbicide to oil (20% to 30% by volume) that effectively controls trees up to 6 inches in diameter at a low spray volume. The basal oil carrier can be kerosene, diesel oil, or a more refined substance such as mineral oil and other naturally derived oils. Many applicators tend to prefer a refined, low-odor oil carrier, which also has fewer environmental impacts than diesel oil or kerosene. There are ready-to-use formulations and blending services available that can eliminate the need for choosing oil carriers and mixing solutions prior to application.

Basal herbicides are typically applied with a backpack application unit equipped with oil-tolerant seals. The backpack unit utilizes a low-volume wand that can deliver a small amount of herbicide mixture to the lower stem of target species. Fixed-pattern or adjustable nozzle tips are available to increase unit flexibility. The wand should have tip shut-off capabilities to avoid having the spray solution run out of the wand after spraying the stem. The entire circumference of the lower stem of target species is sprayed to wet, but not to the point of runoff. Basal applications can be made at any time of the year except when snow or water prevents spraying stems to the ground line, although they are most effective when applied in the late dormant season (from late winter to early spring) rather than in the late fall or early winter periods.

FIGURE 4.24: Cut/Stump Herbicide Application

Cut Surface

Cut surface or cut stump applications involve hand cutting incompatible target vegetation followed immediately (at least within 1/2 hour) by a waterborne herbicide application to the exposed cambium layer along the perimeter of the stump surface (Figure 4.24). The treatment window can be extended by up to 6 months if the herbicide solution includes a penetrating oil. If the latter method is employed, any exposed bark and root flares should be treated to the point of runoff to the root collar zone, in addition to treating the cambium layer. Indicator dyes can be included in the solution to help identify stumps that have already been treated.

TIPS *Long-term cost savings can be realized by using the cut stump treatment method on tree removals to prevent resprouting.*

Immediate cut surface applications are typically applied with a hand-held trigger spray bottle. Because of the small amount of herbicide solution that is applied very close to the cambium area along the edge of the stump surface, there is minimal opportunity for non-target or off-site contamination. Delayed applications may require a backpack applicator as a result of the greater volumes of herbicide solution that must be applied to each stump.

This is the preferred application technique in areas containing low to moderate densities of incompatible target stems where hand cutting is the preferred maintenance technique and herbicides can be used. Cut stump applications can be made year-round as long as snow does not prevent the cutting of stems at ground level. However, tardiness in the application or outright misses can drastically influence the effectiveness of the treatment. Treatments done in the early spring when tree sap flow is high can also have reduced effectiveness.

4

Woody Residue Management

The removal of woody residue (i.e., vegetative debris) resulting from vegetation management activities is sometimes necessary. In these situations, it is chipped into a truck and hauled from the work site for disposal at another location. Particularly in urban or residential areas, it is likely that this will continue to be a common method for disposing of woody residue at most electric utilities. However, electric co-ops should be aware of alternative disposal techniques that can result in significant cost savings.

Table 4.1 shows the relative cost of different woody residue disposal methods based on records obtained from several utilities. Alternatives to chipping and hauling residue are generally feasible only in less populated rural areas, but the savings associated with a "least-handled" approach warrant pursuing these techniques whenever possible.

TABLE 4.1: Relative Pruning Costs Based on Alternative Disposal Methods

Method	Index	Relative Savings
Chip and haul off site	1.00	—
Chip and blow on site	0.84	16%
Hand pile	0.72	28%
Lop and scatter	0.64	36%

When chipped into a truck and hauled away from a work site, locating dump sites for woody residue can present difficulties. Many landfills no longer accept vegetative material, and those that do accept it may charge tipping fees, which add to the cost of vegetation management.

Woody residue resulting from vegetation management activities that must be hauled from the work site should be managed as economically as possible. A considerable amount of non-productive time can be spent driving long distances to dispose of chips, so several potential sites that will accept woody residue should be available whenever possible. Avoid placement of chips in landfills where tipping fees apply unless non-fee disposal options are not available.

Many electric co-ops have found that, with a minimal amount of investigation, locating suitable, non-fee disposal locations close to work sites is not that difficult. In many locations, property owners, farms, nurseries, etc., willingly accept, and will even request, loads of wood chips. Keep records of locations where wood chips can be utilized and refer them to the vegetation management crews when they are working in the vicinity of locations that will accept this material. Some utilities will even move chips and some woody debris to other nearby R/W locations, which is a practice that should also be considered.

Wood resulting from tree pruning or removal operations can present disposal problems as well. As with pruning debris, a "least-handled" approach will be the most cost-effective.

Many utilities simply leave larger diameter wood on site in manageable log lengths, which, in most cases, is quickly claimed for firewood or other merchantable applications. In general, co-op vegetation management crews should refrain from splitting wood or even cutting it to firewood length, unless it is cost-effective. These practices are usually very time consuming and detrimental to program cost-effectiveness.