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TO: All Electric Borrowers

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PURPOSE: The purpose of this guide is to highlight the key engineering principles and methods used in the preparation of long-range plans that will assure sound, long-range economic conclusions for owners, engineers, and consultants.

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2/16/17
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ABBREVIATIONS

$D	Distribution Costs (Plan PW for OOS)
$DP	Delivery Point Surcharge Costs (PW for OOS)
$LD	Primary Line Losses (Plan PW at Distributor/Cooperative Costs for OOS)
$LPS	Primary Line Losses (Plan PW at Power Supplier Costs for OOS)
$S	Substation Costs (Plan PW for OOS)
$TL	Transmission Line Costs (Plan PW for OOS)
AAC	All-Aluminum Conductor
AAAC	All-Aluminum Alloy Conductor
ACAR	Aluminum Conductor, Alloy-Reinforced
ACSR	Aluminum Conductor, Steel-Reinforced
AFC	Annual Fixed Charges
AMR	Automated Meter Reading
APP	Alternate Preferred Plan
CFR	Code of Federal Regulations
CPR	Continuing Plant Records
CRN	Cooperative Research Network
CU	Copper
CWP	Construction Work Plan
DA	Distribution Automation
DG	Distributed Generation
EEC	Engineering and Economic (Design) Criteria
FERC	Federal Energy Regulatory Commission
G&T	Generation and Transmission Cooperative
GFR	General Field Representative
GIS	Geographical Information System
HMW	High Molecular Weight (Underground Power Cable Type)
IEEE	Institute of Electrical and Electronics Engineers
kcmil	Thousand Circular Mil
KWh	Kilowatt-hours
LDSF	Load Distance Service Factor
LF	Load Forecast
LL	Long Level (of LRP)
LR	Long-Range
LRP	Long-Range Plan
LRPG	Long-Range Planning Guide
MW	Megawatts
NERC	North American Energy Reliability Council
NESC	National Electric Safety Code
NRECA	National Rural Electric Cooperative Association
OOS	One-Ownership Study
O&M	Operations and Maintenance
PCB	Polychlorinated Biphenyl
PP	Preferred Plan
PSS	Power Supply Study

PV	Photovoltaic
PW	Present Worth
REA	Rural Electrification Administration
ROW	Right-of-Way for Distribution and Transmission Lines
RTL	Radial Transmission Line
RUS	Rural Utilities Service
SAIDI	System Average Interruption Duration Index
SCADA	Supervisory Control and Data Acquisition
TIER	Times Interest Earnings Ratio
T/L	Transmission Line
UL	Underwriters Laboratories
URD	Underground Residential Distribution
VAR	Volt-Ampere Reactive
XLPE	Cross-Linked Polyethylene

DEFINITIONS

Alternate Preferred Plan (APP). The APP is the long-range plan determined by the planning engineer and support team to be the best system approach to serve the future long-range loads *if* certain parameters assumed in the study significantly change. Such parameters include, but are not limited to, large increase in power costs; large increase in wheeling costs; significant changes in wholesale rate structure, such as transmission lines; new transmission lines become available for use; significant changes in load growth, etc.

Annual Fixed Charges (AFC). The AFC or fixed charge rate is used to annualize capital cost expenditures in economic analyses. The rate is calculated by adding up all annual system expenses and dividing them by the total number of utility plants installed. Often the rate is calculated for a period (e.g., five years) and then averaged. The expense accounts typically used are capital interest costs, operations, maintenance, depreciation, and taxes (if applicable). To illustrate, a project is estimated to have a total cost of $2,000,000. If the AFC has been calculated at 15%, then the annualized costs would be $300,000 (15% × $2,000,000). This implies that if the project is constructed and $2,000,000 is added to the electric plant capital costs, it is going to take $300,000 per year to fully pay for all the operating expenses.
See Exhibit C of this *Guide* for an example of the calculations.

Board. The Board is the Board of Directors and trustees of the Owner. The Board is responsible for setting policy, including final approval of the LRP.

Borrower. A Borrower is an organization which seeks a loan from, or to arrange financing through, the RUS for the purpose of constructing facilities or making improvements to its electric system.

Distribution Automation (DA). DA enables an electric utility to monitor, coordinate, and operate electric system and consumer components in real-time from remote locations.

Distributed Generation (DG). DG—also called on-site generation, dispersed generation, decentralized generation, or distributed energy—generates electricity from many small, localized energy sources. Most industrial electric generation is from large, centralized facilities, such as fossil fuel plants (coal- and gas-powered), nuclear power plants, large solar or wind power farms, or hydropower plants. These large plants have excellent economies of scale, but usually transmit electricity for long distances through transmission lines and substations that sometimes negatively impact the environment.

Economic Conductor Life Analysis. The most economical type of lines can be determined by comparing the life costs of various distribution line conductors. The costs are based on the AFC rate, the cost of capital to build the line, and the estimated line losses based on projected loading and power costs. See Exhibit E of this *Guide* for an example of the calculations.

One-Ownership Study (OOS). OOS refers to the economic analysis of an electrical system where all owners of the various parts of the system (e.g., transmission lines, substations, distribution lines, etc.) are considered together as one entity. The study includes the costs for all owners and considers each alternate plan in order to identify the most economical approach, while taking into account all organizations and their costs.

Owner. The party (or parties) that operate and control the electric system. An electric system typically has many components which include, but are not limited to, the distribution lines, substations, subtransmission lines, and transmission lines. Typically, in the United States, ownership of such components is by one or more parties. The responsibilities of the Owner are generally carried out by the general manager, executive, or person of similar title, who is principally accountable for overseeing the property.

Planning Engineer. The planning engineer is the individual responsible for conducting all necessary studies associated with the LRP, including the preparation of the final report. It is desirable that this individual be a duly-registered professional engineer under the state laws of the electric system and recognized by RUS as being qualified in preparing LRPs. Although the planning engineer is usually an outside consultant, he or she may be a member of the owner's staff or combination of the two. Although many owners' staff engineers compile CWPs, each owner should evaluate the advantage of additional perspectives, skills, and availability of time provided by an outside consultant when involved in the LRP.

Power Supplier. The Power Supplier is an organization from which the Owner purchases wholesale power and energy. The role of the power supplier may be filled by a private investor-owned power company, a governmental agency, or a generation and transmission (G&T) cooperative of which the Owner is a member. In many cases, the owner purchases energy from more than one power supplier. In cases where all purchases are coordinated through one organization, that organization is the power supplier even if it has no generating capacity of its own.

Power Supply Study (PSS). PSS refers to studies completed separately from the LRP. The LRP is completed using, generally, average facility costs and assumptions for substation and delivery point locations. When CWPs are being prepared, PSS are generally completed for certain portions of the system to formally justify the construction of certain projects, such as transmission lines, substations, etc. The PSS is completed in conjunction with the power supplier and transmission line/substation owners using precise budgetary estimates. Typically, the PSS validates the LRP and allows the projects to be budgeted for construction.

Preferred Plan (PP). The PP is the LRP determined by the planning engineer and support team to be the best system approach to serve long-range future loads. The PP is the option that should be followed for all planned future construction in CWPs.

Radial Transmission Lines (RTL). RTL refers to transmission lines that feed one or more delivery points that are electrically fed from only one source. No alternate loop feed is available for an RTL.

Sensitivity Analysis. After determining the costs for each plan evaluated and the Preferred Plan appears to have been identified, it is important to compare the plans if certain economic parameters varied from what was projected. This process is called the Sensitivity Analysis and is usually carried out for the plans with the closest lowest costs. Parameters typically covered in the analysis include construction inflation rate, load growth, energy inflation rate, present worth rate, and wheeling costs. See Exhibit H of this *Guide* for an example of such analysis.

Smart Grid Technology. This term refers to the new technology available to the electric distribution system for improved operation, protection, and efficiency. The technology is a big step in Distributed Automation, allowing system equipment to record events—and appropriately respond—for improved system performance. Equipment that supports the Smart Grid Technology includes automatic meter information systems, protective relays of substation feeder breakers, line controlled switches and reclosers allowing for fault isolation and load transfers, etc.

Substation Firm Capacity. *Substation* Firm Capacity is a term that refers to an electric distribution system that has a spare substation transformer or mobile substation or transformer available for each of the transformer sizes, voltages, etc., on the system. The spare transformer may be stored at a substation or in the equipment storage yard. *System* firm capacity implies that spare transformers are stored at *some* location on the system. *Site* firm capacity implies that the spare transformer is stored at the substation for which it is intended, the result of which improves reliability and aids in system O&M. This is often the practice of some systems where there are loads that have paid for such capacity or where loads are critical and high-priority in nature.

System Circuit Diagram. The System Circuit Diagram is typically an electric system map showing only electric plant components, such as distribution lines, substations, transmission lines, and some key, land-based information. The map is clear of a lot of details so that planned construction can be shown plainly. The diagram should include line voltage, loading, and voltage drops. The map is used to show planned construction for each LRP, including the load level to which they are to be built. The maps can be paper or digital in form.

System Planning. System Planning is the careful evaluation of an electric power system, the consideration of alternative methods of meeting the electric power needs of the consumers, and the selection of the most promising of the viable alternatives for providing economical, reliable, environmentally acceptable service at a reasonable cost. System Planning by RUS borrowers is manifested in the long-range plan (LRP) and the construction work plan (CWP).

CONTRIBUTORS

The United States Department of Agriculture Rural Utilities Service acknowledges the dedication and technical expertise of all the organizations and individuals who participated in the development of this guide. This guide is designed to help borrowers develop and implement long-range options and plans effectively. This document is based on inputs from members of the NRECA Transmission and Distribution System Planning Subcommittee. Committee members and associates who provided invaluable assistance in preparing this document were:

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1 PURPOSE

This document is intended to provide guidance in the preparation of long-range plans for electric borrowers. It addresses the minimum requirements and responsibilities of system owners, engineers and consultants, and it identifies key engineering principles and methods for reaching sound long-range economic decisions. This guide supports the RUS regulations found in 7CFR1710.250 and replaces existing RUS Bulletin 1724D-101A.

2 THE LONG-RANGE PLANNING PROCESS

Every electric distribution borrower has a responsibility to develop plans for serving existing and future system loads while maintaining customer satisfaction and meeting environmental requirements. Therefore, it is prudent practice for borrowers and their key stakeholders to engage in a structured planning process to develop a long-range plan for achieving those goals. This resulting plan is an engineering and management tool that provides guidelines for operating and expanding the electric distribution system. At a minimum, the long-range plan should:

- Determine the most practical and economical means of serving existing and future system loads while maintaining reliable service;
- Identify changes, such as additions, upgrades or retirements of facilities and delivery points, as they are needed in order to meet system requirements; and
- Estimate capital requirements for implementing the recommended plan.

In most cases, the borrower's planning engineer is responsible for managing the planning process, including conducting all necessary studies and preparing the long-range plan for review and approval by the borrower's senior management and board of directors and others as necessary. The planning engineer may be a member of the borrower's staff or a consultant, or these responsibilities may be shared between staff and consultants.

The planning process utilized and long-range plan produced, including all load forecasts, should comply with all applicable state or other regulatory requirements.

a Study Phases

This guide outlines a seven-phase process for developing the long-range plan. It identifies the primary steps in each phase and highlights critical coordination issues. The process includes:

- Phase 1—Collect and evaluate system data,
- Phase 2—Define engineering and economic criteria or parameters to be used in the study,
- Phase 3—Evaluate design options and cost allocations,
- Phase 4—Select and validate preferred plan,
- Phase 5—Develop transition plans and maps,

- Phase 6—Complete report and system circuit diagrams and
- Phase 7—Present report and obtain final approval.

It may be desirable to undertake some individual tasks from different phases of the process concurrently, but it is prudent to consider the impact this may have on the overall results. The information collected and decisions made in each phase provide the basis for analysis in subsequent phases. That makes it important to complete the phases in the order suggested. Otherwise, revisions in one phase could result in the need for revisions to work already undertaken in subsequent phases. This could delay project completion and potentially increase costs.

b Consultation with Key Stakeholders

It is important for the borrower to coordinate planning activities with other key stakeholders, including the borrower's power supplier, RUS and other lender if necessary. In most cases, the power supplier is also the transmission service provider. If there is a separate transmission service provider, both the power supplier and the transmission service provider should be included in planning process. For convenience, references to power suppliers in this bulletin are understood to include transmission providers.

It is prudent to provide essential information to stakeholders in printed or electronic form. In addition, the borrower should conduct at least four stakeholder meetings to ensure that each organization's interests are adequately considered and addressed:

- Meeting 1—Preliminary conference for discussion of distribution system data;
- Meeting 2—Engineering and economic criteria conference for review, discussion, and comment on design criteria;
- Meeting 3—Preferred plan review to present preferred plan, economic analysis and sensitivity studies to key stakeholders; and
- Meeting 4—Final report presentation for action by the system's board of directors.

Members of the borrower's management and staff, including key responsible personnel from the operations and maintenance department, and, if appropriate, consultants should participate in each meeting. Representatives of other stakeholder groups should participate as needed. For example, if changes to the transmission system are needed, power supplier participation in Meetings 2 and 3 is essential. If not, it may not be necessary. Since the availability of capital may depend on completion of the long range plan, representatives of RUS and other lenders if necessary should be invited to attend the meetings and kept informed of developments.

While it is often advantageous to conduct the meeting to review the preferred plan (Meeting 3) in person due to the complexity of the data, maps, and other information to be discussed, it may be acceptable to conduct the meetings by telephone or web conferences and email exchanges. The increased use of these technologies can reduce the cost of the planning process and may enable more people to participate.

3 PHASE 1—COLLECT AND EVALUATE SYSTEM DATA

The primary task in Phase 1 is to identify the basic data needed to support the planning process and computer model development. It is essential to collect the best available data in this process. Steps include identifying data requirements, assigning data collection responsibilities and presenting results for discussion at Meeting 1.

Basic system data include, but are not limited to, the following general categories:

- System configuration and operational data;
- Economic parameters and cost estimates;
- Wholesale rates, including any wheeling costs; and
- Anticipated load growth patterns.

A detailed list of data needed to complete a long-range plan is shown in Exhibit A of this *Guide*.

a System Configuration and Operational Data

Required system configuration and operational data includes:

- Transmission line diagrams, distribution circuit diagrams, and/or computer model data reflecting the most current peak-loading conditions experienced;
- Proper feeder wire sizes and number of phases, the location and sizes of capacitor and voltage regulator banks, and the correct location of normal line opens;
- Accurate peak consumer and substation load data;
- Feeder voltage and current readings at substations and along the electric lines;
- System reliability data; and
- Historical cost data for system improvements and line construction.

Required information about key components of the electric delivery system, including transmission and substations, includes:

- Voltages, capacities, and ownership of transmission lines and substations;
- The loading of each substation and available capacity;
- Substation capacity, both firm and spare , if any; and
- The load growth rate for each substation over the last 10 years, if available.

The borrower and its power supplier should discuss their respective plans to determine whether the power supplier has bulk electric plans that could be beneficial to the borrower's distribution system and to avoid duplication of efforts. If the power supplier is a generation and transmission cooperative (G&T), it is important to determine whether the load is being served on-system directly from the G&T's facilities or off-system through another borrower's facilities. Off-system loads sometimes involve wheeling charges, which should be included in the economic analysis. Ownership interests and shared costs of any jointly-owned substations should be identified.

b Economic Parameters

It is necessary to estimate the following economic parameters:

- System annual fixed costs and inflation rates for both energy and construction expenses;
- Construction costs for system components, such as transmission lines and taps, substations, distribution lines and voltage conversion equipment; and
- Present worth and inflation rates, which should be acceptable to the stakeholders.

Costs that are common to all alternate plans under consideration, such as consumer distribution transformers, service drops, sectionalizing equipment, meters and capacitors, are often ignored in economic comparisons, as they typically do not affect the results of the comparison.

c Wholesale Rates

Information about the wholesale energy rate structure of the power supplier and any wheeling costs paid by the power supplier for off-system loads should also be collected. While this information is sometimes ignored, it can make a significant difference in the economic comparison of alternate plans. It is important to identify any delivery point costs paid by the distribution system. Such costs are not necessarily included in a one-ownership[1] economic analysis, but they impact costs indirectly and should be evaluated.

It is important to determine if there are any anticipated wholesale rate increases or changes in wholesale rate philosophy that might transfer direct costs from the power supplier to the distribution system. For example, a power supplier may wish to stop providing subtransmission lines and substations and to transfer the ownership and associated costs of these facilities to its wholesale customers. While this does not happen often, the borrower should be aware of any potential actions that could significantly impact long-range costs.

For example, a power supplier may plan to change from an allocation method of

[1] See Section 10a for more discussion of one-ownership economic analysis.

assigning the cost of substation changes to all customers to a method that directly assigns the costs of such changes to customers served by the substation. This could significantly affect long-range costs and system upgrade decisions.

It is also important to consider territorial laws for the service area being studied. Potential annexation of borrower territory by other utilities requires special consideration and evaluation.

d Load Forecast

It is essential to begin the long-range planning process with a reasonable and supportable load forecast approved by the system's management, board of directors and RUS. Borrowers are typically required to develop a new load forecast every two to three years. Borrowers are required to follow the load forecast regulations in 7 CFR 1710 subpart E. The forecast should include projections of annual kilowatt-hour sales, level and season of annual peak demand and losses for a range of assumptions for each district in the borrower's service territory. Many distribution system load forecasts deal with a 10-year period. It may be necessary to extend the forecast to cover the planning period, typically 20 years (see Section 4c and Section 5a of this *Guide*). Construction projects included in the long-range plan should correspond to forecast requirements.

Stakeholders should review the load forecast for reasonableness and to identify anomalies or flaws. Any adjustments to the approved forecast should be documented and agreed to by the power supplier, borrower and RUS general field representative before proceeding. Borrowers should also comply with applicable federal and state requirements regarding load forecasts.

The long-range plan should identify three to five key load levels (LLs) to serve as benchmarks for construction work plans. Load Level 1 (LL1) is typically the actual load level at the beginning of the study, and the final load level is that projected for the last year of the study. Interim load levels determine the need to construct specific projects. For example, LL1 may correspond to projects schedule for the first three years of the long-range plan. LL2 would be the load level projected for Year 4, corresponding to projects needed in Years 4, 5, and 6. LL3 would be the load level projected for Year 7, corresponding to projects needed in Years 7, 8, and 9, and so on. The load levels, not the date, serve as a trigger for the construction work plan. If, for example, loads fall short of Load Level 2 as predicted for Year 4, construction of projects corresponding to that demand may be delayed. If Load Level 3 is reached in Year 5 instead of Year 7, certain projects may be constructed earlier. There may be different load levels for different parts of the system, and they may trigger construction at different times.

e System Reliability Data

Reliability is a key issue for all electric suppliers. A thorough review of system reliability data is needed to identify weaknesses that can be addressed in the long-range plan and formulate ways to improve system reliability. In general, the components most likely to significantly affect system reliability are transmission lines, substations and distribution feeders. Distribution feeders with smaller conductors or feeders that do not serve as ties for substations are likely to experience more outage time than larger conductors, looped lines, or ties between substations.

The borrower should consider providing on-site backup power for substations that serve high-priority loads, such as large towns, hospitals, commercial and industrial loads. Designs for distribution feeders should provide strong ties between sources for improved reliability. Reliability needs, such as larger conductor sizes and overhead versus underground construction, should be addressed in the design criteria for the long-range plan.

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f Operation and Maintenance Survey

RUS requires its field representatives to conduct a periodic review of the operations and maintenance practices of each borrower. This review will normally be done at least once every three years. The review collects data, such as outage information, losses, power factor, capacity factor and other operational factors. The results of the review are provided to the borrower on RUS Form 300. The review provides a useful overview of the system's operation and maintenance characteristics and identifies areas that need to be addressed. It also includes suggestions for system improvements.

Projects to be included in the long-range plan will be determined by a number of factors, such as costs, including all fixed costs, and the needs identified by the operations and maintenance review.

g Conductor Options

Until recently, conductor selection was driven by load current and voltage drop, but as energy costs increase, line losses are becoming an increasingly significant economic factor. Choosing the correct conductor sizes can help the borrower minimize costs. An economic conductor life analysis is a useful tool for determining the most economical conductor voltages and sizes for different construction options, considering losses, line load levels and voltage drops.

The analysis estimates the total ownership cost of conductors of different sizes over their expected life. The information allows the system to weigh the higher initial cost of larger conductor sizes against long-term cost savings due to lower line losses and lower voltage drops. Other factors considered in selecting a conductor include:

- Conductor Availability. The borrower should discuss the availability of different conductors under consideration with its wire vendors. Suppliers should be able to provide the selected conductor during emergencies as well as for routine construction.
- Storm Situations. Other systems that could be expected to help restore power in storm and other emergency situations should have the ability to work on the conductor sizes utilized.
- Tooling and Connectors. The borrower should review the cost of the tooling and connectors required for the conductors under consideration to determine whether any would add significant costs.
- Switching Capability. An economic conductor life analysis provides a recommended minimum conductor size, based on the initial load and expected load growth for a line. However, if main tie lines will be used as backup for other feeders, it may be prudent to select a larger conductor size in order to improve system reliability.

Conductor options should not be limited to those currently in use on the borrower's system. While ACSR conductors have been utilized extensively by electric distribution systems over many years, other available conductors—such as AAC, AAAC, and ACAR—should be included in the evaluation. It is important to note that the different characteristics of different conductors may require different modeling techniques.

Borrowers may find it helpful to find out which conductors other electric systems in their area are using and why.

There is typically little cost difference in the pole, pole-top assembly, guying and anchoring for conductors of similar strength and size. The primary differences among conductor options are the cost of the conductor in dollars per 1,000 feet and the cost of losses.

Exhibit E of this *Guide* provides an economic conductor life system analysis. Additional discussion of the factors involved in such an analysis is included in Appendix 1 of this *Guide*.

4 PHASE 2—DEFINE ENGINEERING AND ECONOMIC CRITERIA

The tasks identified in Phase 1 should be completed before proceeding to Phase 2. The information collected is used to establish the basic engineering and economic criteria (EEC), or assumptions, for the economic models developed to compare alternate plans for meeting future needs.

Exhibit B of this *Guide* provides an example of engineering and economic criteria. Additional details and discussion items identified below are included later in this guide.

a Basic Cost Estimates and Parameters

The following basic cost estimates and parameters are needed as input to the economic models of alternate plans:

- Cost estimates for construction of various distribution lines;
- Cost estimates for 25-kV line reinsulation and conversion, such as step banks and consumer transformers;
- Cost estimates for uprating existing substations by voltage class and MVA capacity;
- Cost estimates for new substation alternatives by voltage class and MVA capacity;
- Cost estimates for transmission lines and taps by voltage class;
- Economic parameters for borrower and power supplier, including cost of losses, annual fixed charge rate, transmission O&M costs, distribution O&M costs, substation O&M costs, avoided energy cost, distribution energy cost, inflation rate for energy costs, inflation rate for construction costs, present worth rate, delivery point costs and total value of distribution plant;
- Reliability criteria for transmission line looping and substation firm capacity, if available;
- Projected system peak loads by load levels from actual load level at the beginning of the study to the projected requirements for the final year of the study; and
- General criteria for the overall plan, such as distribution system design and operating criteria, line and equipment loading limits, and multiphase conversion limits.

b Transformer Criteria

It is useful to establish a criteria for replacement of substation transformers, based on capacity and age. For example, it is prudent to replace any that have significant maintenance problems, have suspect levels of combustible gases or show signs of failure. Transformers that have been in service more than 35 years are likely to experience major maintenance costs during the planning period. The cost of maintaining versus replacing this equipment should be compared in the economic analysis.

Several factors should be considered in establishing criteria for sizing transformers for substations to ensure that equipment remains in service over its useful life, including the initial load and growth rate at the substation location, potential load shifts due to new substations and load shifts during emergency situations. Areas of the system with low growth rates may require different criteria for sizing transformers than areas of the system with higher growth rates. However, it may be more economical to establish a standard transformer size for the entire system to accommodate changes in load growth patterns during the planning period. There may also be cost benefits to purchasing the same size transformer for multiple locations. This provides the flexibility to move units as load patterns evolve. Single versus two three-phase transformer configurations should be evaluated from a reliability and maintenance perspective.

c Planning Period

Load forecasts normally project loads for a 10-year period. For long-range planning purposes, it is usually desirable to predict loads for a longer period. The planning period should be at least long enough for the system to need enough upgrades and/or new construction to permit the exploration of several alternate plans and system configurations. In general, this is the amount of time it takes for the system load to double, about 20 years at an annual demand growth rate of about 3.5 percent and 25 years or more for a system with a 3.0 percent growth rate. Planning parameters for systems with growth levels of less than 2 percent should be considered on an individual basis.

It is important to choose a period that will stress the electric system to force change so that options can be evaluated.

d Design Options

The engineering and economic criteria should establish several design options for evaluation. Options for adding capacity, assuming the existing system is operating at 12.5 kV or less, include:

- Add no new delivery points, increase the capacity of existing lines and substations and maintain the same distribution voltage levels;
- Add no new delivery points, increase the capacity of existing substations and convert the distribution voltage to 25-kV operation;
- Add new delivery points and/or increase the capacity of existing substations and maintain the same distribution voltage levels; or
- Add new delivery points and convert the distribution voltage to 25 kV.
- Consider a hybrid system with both 12.5kV and 25kV distribution.

The borrower should study the options that best fit system conditions and evaluate the economic and operational benefits for each.

e Stakeholder Agreement on Engineering and Economic Criteria

Key stakeholders should have the opportunity to review, discuss, offer comments on and agree to the engineering and economic criteria. Meeting 2 provides an opportunity for the parties to confer and reach agreement on these issues. Agreement on the criteria between the borrower and power supplier is critical to the validity of the study.

5 PHASE 3—DEVELOP DESIGN OPTIONS AND COST ALLOCATIONS

Key stakeholders should agree to the engineering and economic criteria established in Phase 2 before proceeding with Phase 3. The next task in the planning process is to develop the design options identified in Phase 3 and estimate costs for each option.

a Load Forecast Issues

It is often necessary to extrapolate the system's approved load forecast to match the long-range planning period. One way to do this is to identify different growth areas on the system, based on current experience, large loads and expected changes. The basic process for this is:

- Identify areas of higher, average and lower growth on the system circuit diagram.
- Allocate load and estimate the growth rate in each area based on the total system peak demands in the load forecast.
- Use this information to extrapolate the load forecast to match the planning period.

It is also important to determine whether all areas of the system peak during the same season. For example, a system that peaks in the summer overall, may serve an all-electric subdivision, creating an area within the system that peaks in the winter.

Other acceptable methods of load allocation include projecting from individual feeders for small systems or using the square mile grid analysis approach. In addition, actual individual consumer demand data may be available to systems that have deployed advanced metering infrastructure (AMI) or a smart meter system.

Large power and residential loads are usually forecast separately. One way to project large power loads in the 150 to 1,000 kW is to double demand over the life of the study. This approach assumes that existing loads will grow and/or new loads will be added in the vicinity of existing large power loads.

Large power loads greater 1,000 kW are usually forecast individually, based on information provided by the customer. These loads usually do not add significant capital requirements, as large commercial customers typically make a contribution in aid to construction to pay for any changes to the system needed to service their load.

To simplify the system design process, loads are typically assumed to have a 95 to 98 percent power factor so that designs for alternate system configurations can omit line capacitors. This reduces design time and costs, and does not significantly affect the final economic comparisons. Likewise, sectionalizing and system protection costs are typically omitted as well. However, the costs for capacitors and sectionalizing devices usually are included in the total plant projections.

b Distribution System Design and Construction Budget

The next step is to develop a distribution system design and construction budget for each alternative under consideration. Appropriate conductors were identified in the economic conductor life evaluation (see Section 3g of this *Guide*). The same kVA load capacity should be used for each option so that end-of-line accumulated voltage drops are approximately equivalent. For example, if the 25-kV option has a total drop of approximately 10 volts, then the drop on the 12.5-kV option should also be approximately 10 volts. This approach provides comparable service levels for each option, which is necessary for a true economic comparison.

The costs associated with each alternative should be calculated for the power supplier and borrower using the one-ownership approach (see Exhibit G of this *Guide*). That is, the economic analysis is conducted as if all parts of the delivery system, both transmission and distribution, were owned by one entity. This helps identify the alternative that will deliver power to the consumer at the most economical overall cost, even though different options might require different levels of investment by the borrower.

For comparison purposes, line costs are usually levelized over the study period. If a borrower has delayed maintaining the system and increasing capacity to the point that it is experiencing high voltage drops, the borrower will need to initiate a significant construction program as soon as possible to correct the problem. Consequently, more capital costs will be incurred in the early years of the study, and the levelized cost will be higher than if the same construction program were spread evenly over the planning period.

Substation and transmission line capital costs are generally allocated to the year in which new capacity is needed. Annual losses, both in primary lines and transmission lines, if appropriate, are forecast using an appropriate, calculated compound growth rate.

A substation loading chart showing substation capacities and required improvements for each alternative under consideration is needed in order to properly allocate substation and transmission line costs.

Exhibit F of this *Guide* provides a sample substation loading chart.

c Reliability Issues

Reliability of service should be evaluated for each alternative. Normally, installing new substations to establish new load centers shortens the distribution lines, which should improve reliability. Converting existing distribution lines to a higher voltage instead may decrease reliability. The expected reliability of the conversion option can be improved by:

- Installing two separate substation power transformers or making provision for a mobile substation to increase reliability,
- Establishing main substation tie feeders for transferring load from one substation to another,
- Establishing loop-feed transmission to a substation, or
- Employing a more sophisticated distribution line sectionalizing scheme.

Using one or more of these options can help establish comparable reliability for options under consideration.

It is important for the economic analysis that the alternatives under consideration be based on comparable assumptions. This means that projected load levels should be the same for each year, changes in existing substation capacity should be scheduled in approximately the same years and voltage drops on circuit extremities should be comparable for all alternatives. Close coordination between all parties involved in designing the system alternatives and allocating costs is essential to ensure that these conditions are met. If alternatives are based on different criteria, such as different load levels or different schedules for substation capacity increases, the resulting economic analysis will not be sound or valid.

6 PHASE 4—SELECT AND VALIDATE PREFERRED PLAN

The analysis outlined in Phase 3 should be completed before proceeding to Phase 4.

The principal task of Phase 4 is to select and validate the preferred long-range plan based on a comparison of the alternative system designs and cost allocations completed in Phase 3. The plan selected should not be limited by the existing system. Although there are inherent benefits in continuing to use installed facilities, a proposal that requires early retirement of those facilities should be adopted if it results in significant cost savings.

a Compare Costs to Determine Preferred Plan

The primary factor in choosing a plan is usually full life-cycle cost. It may be necessary to compare a plan with high initial capital costs but low annual costs to a plan with lower capital costs but high annual costs. A plan chosen just for low capital costs or just for low annual costs may not be the plan that provides the best service at the most reasonable overall cost to the consumer. There are numerous methods of performing this type of economic comparison. Regardless of the method used, the following factors should be included in the economic evaluation:

- Time Value of Money, or Present Worth Analysis. Dollars spent this year are worth more than dollars spent next year.
- Inflation in Both Energy and Construction Costs. Energy, labor, and material costs are likely to increase significantly during the planning period.
- Line Losses. The cost of losses on the distribution system and transmission lines, if appropriate, should be included in the cost of service.
- Operation and Maintenance Costs. This is usually estimated as a percentage of added plant.
- Annual Fixed Charges. This is usually estimated as a percentage of added plant.

The present worth method of economic evaluation is preferred in most situations, but there should be an additional comparison to annual costs to help validate the economic results and aid in the selection of the preferred plan.

The preferred plan is usually the option with the lowest one-ownership costs of all the alternatives being considered. If two plans have comparable one-ownership costs, then the plan that more equitably spreads the capital costs between power supplier and distribution system or provides the highest reliability should be chosen.

Exhibit G of this *Guide* provides a sample economic analysis workbook, including a summary list of all plans considered. RUS Bulletin 1724D-104 provides another example of an engineering economics workbook that could be used.

b Perform Sensitivity Analysis to Confirm Preferred Plan

It is important to conduct sensitivity studies for any plans that appear to be reasonable in order to verify the results of the economic analysis and selection of the preferred plan. This analysis should include variations in key economic parameters, including:

- Present worth rate,
- Energy inflation rate,
- Construction inflation rate,
- Fixed charge rate,
- Load growth and
- Wheeling costs, if applicable.

The basic assumptions for these factors should be increased and decreased to determine if the preferred plan is still the best choice under different economic conditions. It is helpful to present the results of the sensitivity analysis in both tabular and graphic form to aid in interpretation and communications.

Exhibit H of this *Guide* shows an example of a sensitivity analysis.

If the results of the sensitivity analysis are close, other factors that may be considered include:

- Energy Conservation. If one plan results in higher long-term energy savings, that plan should be given higher priority.
- Excess Capacity. While each plan must provide the minimum capacity required to serve the projected system load, a plan that provides more excess capacity at the end of the planning period should be given higher priority.
- Service Reliability. While each plan must provide a minimum level of service reliability, a plan that provides better service reliability should be given higher priority.
- System Manpower and Labor Costs. The advantage depends on conditions in the borrower's service territory. If there are manpower shortages and labor costs are above the national average, the most labor-intensive alternative may be less desirable. If labor is readily available in the community, the alternative with the larger construction program may be more desirable.
- Flexibility. One plan may provide a greater capability for expansion at the end of the planning period while another plan may require radical changes in basic design parameters to expand at that point. The plan with the longest useful life should be given higher priority. A plan that defers major expenditures and provides more flexibility to take advantage of future developments in technology should be given higher priority.
- Solution to Chronic Problems. The plan that best addresses a chronic system problem should be given higher priority.

A cost-benefit analysis may be helpful in evaluating alternatives based on these factors.

While economic comparison is the primary basis for selecting the preferred plan, the final decision should be based on good engineering judgment and the best available information. If there is significant uncertainty about a key assumption, such as load growth in a specific area, it may be desirable to designate an alternate preferred plan. The alternate preferred plan can be included in the planning documents and ready for implementation. The final decision on which plan to implement can be made once the parameters for the assumption in question have been firmly established. All work sheets, sketches, maps, and other backup used in developing and selecting the preferred plan and the alternate should be included in the long-range plan supporting documents and retained for future reference.

c Present Preferred Plan for Review and Acceptance

The final step in Phase 4 is to present the preferred plan and any alternate preferred plans to the stakeholders at Meeting 3 for review and acceptance (as appropriate). All economic analyses, including any sensitivity analyses, should be presented and fully discussed. The borrower should send summaries of preliminary results to stakeholders for their review prior to the meeting.

At the meeting, participants should review and discuss the reasonableness and feasibility of the preferred plan and any alternates. If the review reveals any serious problems with the analysis or plans, it will be necessary to propose a solution, revise the economic analyses and, depending on the extent of the revisions, conduct another review. Once the preferred plan is agreeable to all, it should be approved by the borrower and power supplier.

The power supplier should provide written validation of three aspects of the study:

- The transmission provider and power supplier were included in the long-range planning process.
- The power supplier considers the preferred plan and any alternate preferred plan to be reasonable guides for the borrower's long-term needs in light of the power supplier's system configuration and long-range plans.
- The transmission provider and power supplier will consider the distributor's preferred plan and alternate preferred plan recommendations in their own long-range plans.

This letter should be included in the long-range plan report as supporting data.

7 PHASE 5—DEVELOP PLAN FOR IMPLEMENTING LONG-RANGE PLAN

The preferred plan and alternates, if any, provide a vision of the borrower's system, including expected system upgrades, additions and retirements, at a future date. This vision is achieved through the construction work plan, which is synchronized with the preferred plan through the load levels identified in Phase 1 (see Section 3d of this *Guide*).

The preferred plan clearly states what needs to be accomplished at each load level in the construction work plan and identifies the major components for upgrades and new construction. In practice, the construction work plan will likely need to specify additional work to complete the configuration in the preferred plan and maintain adequate system capacity and acceptable voltage drops.

Ideally, the long-range plan should be completed before the construction work plan. As a practical matter, a borrower may need to, with the agreement of the RUS general field representative, complete its next construction work plan after completing the long-range plan through Phase 4. This allows the borrower to apply for loan funds in a timely manner. For example, the construction work plan to meet Load Level 2 would be based on the design criteria established by the preferred plan, but the remaining phases of the long-range plan would be completed after the construction work plan.

8 PHASE 6—COMPLETE REPORT AND SYSTEM CIRCUIT DIAGRAMS

It is important to document the long-range planning activities, including analysis and results, in a complete written report. Information to be presented in the report includes:

- The engineering analysis of the existing system and the preferred plan;
- Information about alternate preferred plans, if any;
- The strategy for the implementing the preferred plan;
- Summaries of the analysis of options no longer under consideration;
- A discussion of the economic analysis, including methodology and a cost comparison of the results for each alternative;
- An explanation of the reasons for recommending the preferred plan;
- Suggestions for standardizing items such as conductor sizes, line reinsulation design levels, and substation power transformer sizes and voltages
- Summaries of findings and assumptions to aid the periodic review of the continued validity of the plan and support the formulation of revisions or amendments if necessary; and
- A bibliography identifying all data, external documents and judgment sources.

It is useful to include small sketches of the system or sections of the system to illustrate or replace written descriptions and to present summaries of basic data, statistics, economic comparisons, costs data, and engineering analysis in the form of tables or graphs whenever possible.

In addition, the report should include the following tables and diagrams:

- A table showing new construction and major system improvements for substations and related transmission line improvements along with the estimated costs and expected in-service dates. The table should also include equipment to increase the capacity of services, transformers, meters, sectionalizing, regulators, capacitors, etc., as well as annual projections of costs for connecting new services.
- A table showing annual cost estimates for ordinary replacements, or new equipment that does not result in an increase in capacity or quality of service, that result from factors such as normal wear and tear, rot, corrosion and damage.
- A table showing electric plant costs broken down by the categories of new services and system improvements. This will enable management to relate investment in facilities to the time of installation for use in the preparation of long-range financial forecasts.
- A table summarizing key information about the borrower’s electric plant, including actual data for the most recent 10 years and projected data for the long-range study period. Information to be tabulated includes number of new services, system improvements, system retirements, and peak demands. The data should be used to generate accompanying graphs showing total electric plant and total plant per peak kilowatt.
- Substation loading charts for each load level, including the percent loading.

- A circuit diagram for the base, or existing system.
- A circuit diagram for the system as planned at the end of the planning period. This diagram should show projected loads along with new construction and system improvements colored coded for the load level at which the improvements are anticipated. The supporting data should include a primary analysis for each load level to allow for easy evaluation of system voltage drops and losses. Typically, only unregulated voltage drops are included; however, regulated drops may be indicated as well if desired or required.
- A transmission line diagram showing all transmission lines crossing the borrower's system, including those owned by the power supplier and other transmission providers. The diagram should include all existing substation delivery points as well as any new delivery points in the preferred plan and alternate plans, if appropriate.

It is not necessary to include the detailed calculations for the engineering analyses and other planning investigations in the report. However, this information should be retained as reference material. The borrower should retain calculations and work sheets as long as the plan is valid and in effect.

The draft report should be presented to appropriate stakeholders for review and comment. Any issues raised by the review should be resolved before the report is finalized. The final report should be certified by a registered professional engineer licensed to practice in the state where the borrower is headquartered.

Exhibit I of this *Guide* provides a suggested table of contents for a long-range engineering plan that can be used as a guide in organizing report contents.

Form 260 provides a checklist for the long-range plan document. Form 261 provides a summary of the long-range plan results, including general data, line miles, substations and metering points, and plant investment projects.

A long-range plan is expected to remain valid for seven to 12 years. The final report and supporting data should be retained in a manner suitable for long-term use.

9 PHASE 7—PRESENT FINAL REPORT FOR BOARD APPROVAL

The final long-range plan report should be presented to the borrower's board of directors for their review and approval. The presentation should include a discussion of the issues associated with electric distribution system planning, the options considered, the results of the analysis, and the recommendations for the preferred plan and alternate plans if any. It is often helpful to schedule a special meeting for this purpose. Once the review is complete and any issues raised resolved, the board of directors should pass a resolution approving the plan. The borrower may also need to obtain formal acceptance of the plan by their lenders.

Copies of the approved report should be provided to the borrower's power supplier, and other lenders, if necessary, and state public service commission, if required. If requested, supporting documents should also be provided. The borrower should consider providing these materials in an electronic rather than printed format.

10 SPECIAL CONSIDERATIONS

a One-Ownership Studies

Most distribution borrowers in the United States do not own transmission lines and substations, but the costs for these facilities should be considered in the planning process. The one-ownership approach to economic analysis evaluates various alternatives as if all transmission and distribution facilities used to deliver power to the consumer were owned by one entity. It identifies the plan that has the lowest present worth regardless of which entity owns transmission and distribution facilities. Only costs paid to outside parties are included in the study. Money exchanged between owners of the facilities involved is excluded. It should be noted that generation costs are typically evaluated separately from transmission and distribution costs and are not included in the one-ownership study.

The following example shows a sample analysis of present worth costs of an option using the one-ownership concept.

Electric System Cost Summary	Power Supplier Costs	Distribution System Costs	One Ownership Costs
Transmission Line Costs ($TL)	$TLPS	–	$TLPS
Substation Cost ($S)	$SPS	$SD	$SPS+$SD
Distribution Costs ($D)	–	$DD	$DD
Wheeling Charges ($WC)	$WC	–	$WC
Transmission Line Losses ($TLL)	$TLL	–	$TLL
Primary Line Losses @ Distribution Costs	($PLD)	$PLD	–
Primary Line Losses @ Pwr. Supplier	$PLPS	–	$PLPS
Total Costs ($TOT)	$TOTPS	$TOTD	$TOT

In this example, transmission line costs, substation costs, distribution costs and the cost of primary power supplier losses are costs incurred by either the power supplier or the distribution system and thus qualify as one-ownership costs. The cost of primary distribution losses and delivery point costs are included wholesale rates paid to the power supplier by the distribution system. Therefore, the same costs are expenses for the distribution system and a source of revenue for the power supplier. To avoid duplication, these costs are subtracted from power supplier costs. The economic comparison in Exhibit G also includes one-ownership costs.

There are a number of acceptable ways to calculate the costs inputs to a one-ownership analysis. It is important for the borrower to work with its power supplier to reach agreement on how losses are handled.

b Conversion to a Higher Distribution Voltage

One option for meeting future needs is to convert the distribution system's existing operating voltage to a higher voltage, for example, 4.16 kV to 12.47 kV, 12.47 kV to 24.9 kV, 12.47 kV or 24.9 kV to 35 kV. Today, most electric distribution systems operate at the 12.47 kV level, and conversion to 24.9 kV is the most common option considered. It is rare to find distributors operating at 4.16 kV level or 35 kV. However, the economic and operational parameters of all options should be considered in evaluating future system needs.

An economical approach to adding system capacity is to raise the primary voltage level from 7.2/12.47 kV grounded-wye to 14.4/24.94 kV grounded-wye. This reduces the line current by 50 percent, reduces both the total voltage drop on the circuit extremities and primary line losses to 25 percent of the 12.47 kV levels, and may add to costs.

Conversion to a primary distribution voltage of 25 kV can be the most economical approach when transmission lines are not readily available in service areas needing additional capacity. This is a good option when it would be necessary to construct more than five miles of additional transmission line to support new substation and delivery point taps. The higher distribution voltage allows for twice the 12.47 kV load and usually supports the use of smaller primary line conductors, generally less than 477 kcmil ACSR. The main difference in line construction between the two voltage levels is the pin and insulator. However, the 125 kV BIL at 14.4 kV distribution transformer costs may be more than the 95 kV BIL at 7.2 kV units.

Two methods are used in the field for 25-kV conversion. One is conversion by phases, using single-voltage consumer transformers. The other is by circuit, using dual-voltage, 7.2-kV × 14.4-kV consumer transformers. The first method may be less expensive, but the second method may be preferred due to safety and reliability considerations. The second method can be accomplished more systematically with two- or three-person crews.

Single-phase, platform-mounted autotransformers are no longer recommended for use in the primary voltage conversion process as the devices are unreliable for high-level through-faults. The best approach to stepping primary voltages—considering all installation costs—is the use of three-phase pad-mounted transformers. The underground residential distribution (URD) method eliminates platform mounting costs of units, especially if large two-winding units are used. The pad-mounted step transformers are typically two-winding transformer banks of 5 MVA or less. Lower weight 7.5 MVA and 10 MVA pads are available in the autotransformer configuration at a reasonable price.

The system design for voltage conversions should also be practical and reliable for operations. A plan that uses many permanently installed step-down transformers is unreliable because system protection and sectionalizing is difficult. At 25 kV, it is preferable to convert major services areas, such as substations and long feeders, and eliminate the use of step transformers for long taps with many distribution transformers.

The use of step transformers for long periods of time should be avoided if possible. They can be useful during the conversion process but generally should not be used in permanent installations. An exception is the installation of step transformers at key tie points where the distribution voltage changes. In this case, they are in place for use in emergencies and load transfers, and typically do not carry load. Step transformers may also be needed in underground distribution systems.

With this approach, losses from step transformers can be ignored and the number of step banks for the conversion process can be greatly reduced.

Operating at the higher distribution level of 25 kV has advantages and disadvantages. Advantages cited include:

- Reinsulating and converting the distribution system can revitalize an old system and eliminate old equipment that has caused problems;
- The amount of overloaded lines may be reduced;
- Excessive voltage drops may be eliminated;
- It may reduce the need for line voltage regulators, a high-maintenance and high failure rate device; and
- It can reduce system losses by two to three percent.

Disadvantages cited include:

- The system may experience more feeder outages than at the lower voltage, because the higher voltage will fault to ground through tree branches, whereas the lower voltage system will burn the branches and trees;
- More consumers are served on a given feeder, so outages have a greater impact on system reliability; and
- Operating expenses are higher for systems using both 12.5-kV and 25-kV equipment.

Operating a 25-kV system requires more aggressive right-of-way maintenance than a lower voltage system to reduce and avoid outages caused by vegetation. Since a 25-kV system serves more consumers per substation, per feeder and per tap, it may require additional consideration to sectionalizing capabilities and reliability issues.

Converting to 25 kV does not provide an economic advantage for every system. Systems with extensive transmission lines in their service areas and reasonable substation construction costs may find it difficult to justify the conversion. Systems experiencing growth of less than two percent per year will also find it difficult to justify the conversion on an economic basis. In some cases, it may be desirable to insulate for 25 kV at an early date in preparation for full conversion at a later date, such as when an older system needs to be essentially rebuilt or when part of a system is already operating at 25 kV. The added costs for the higher insulation level are low and may provide significant benefits in the future.

RUS Bulletin 1724D-105, "Rural Distribution System Conversion Considerations," provides additional information on system conversions.

c Transmission Line Losses

Transmission losses can be a factor when considering conversion from one transmission line voltage to another, but in most cases transmission losses are common between plans and can be ignored. The power supplier can provide guidance as to whether or not to evaluate transmission losses in the long-range system study.

When an alternate plan transfers load from one transmission line to another, it may be necessary to consider transmission losses. Moving load served on a heavily loaded transmission line to a lightly loaded transmission line or from a high-impedance transmission line to a low-impedance transmission line may reduce transmission losses enough to make one alternative more attractive than another. Shifting load in the opposite direction may reduce an alternative's feasibility, particularly if the load being moved is a significant portion of the rating of the line.

When plans involve conversion or elimination of subtransmission lines with voltages $\leq$ 69 kV, it is prudent to calculate the transmission line losses at the one-ownership level. Subtransmission line losses can be significant, especially when lines are close to overload and carry load factor loads greater than 45 percent for distances of more than 20 miles.

d Radial Transmission Line Reliability Assessment

The long-range plan should address the reliability of delivery points, especially those served by long, highly loaded radial transmission lines. While this is often considered the power supplier's responsibility, from a reliability standpoint it is desirable to view the electric system as a total unit. The power supplier and distribution system should jointly plan for delivery points in order to improve system operations and reliability.

Appendix 2 of this *Guide* outlines a procedure for assessing radial transmission lines.

e Long-Range Capital Expenditures for Slow-Growing and Aging Systems

While long-range planning typically focuses on meeting needs resulting from system growth, other issues must sometimes be addressed. For example, borrowers with older systems may need to replace aging plant before system reliability falls to unacceptable levels. Systems experiencing slow or declining growth may need to plan for retirement of existing plant.

Such conditions and their capital needs should be addressed in the long-range plan. A systematic evaluation will help determine which replacement alternatives provide the most benefits based on system operating conditions, capital costs, electric rates, reliability and the ability to get the work accomplished in a timely manner.

Appendix 3 of this *Guide* provides additional information about this process.

f Use of Distributed Generation and Smart-Grid Technology

Borrowers should be aware of the potential impact of emerging energy policies and initiatives on the planning process. Distributed generation (DG) has the potential to impact long-range planning in the electric utility industry. Significant growth in the use of distributed resources was predicted in the 1990s in anticipation of deregulation and new opportunities for competition. Deregulation has not been adopted as then expected. There were, however, some successful deployments, which provided practical experience and successful proofs of concept.

Today, global environmental concerns and the expectation of significantly increased energy costs in the future are creating pressure to adopt energy policies that will significantly impact the electric utility industry. Initiatives that support increased deployment of distributed generation, the development of renewable energy sources, both centralized and distributed, higher energy-efficiency standards, demand-side management, and similar smart grid applications have the potential to radically change the way electricity is provided to the consumer.

The goals of current energy policy include increasing efficiency, reducing demand or, at a minimum, reducing the rate of growth, and increasing reliance on domestic resources. If these goals are achieved, there will be new design criteria and a shift in emphasis from system performance to system maintenance and the sustainability of existing infrastructure. Although the impact is hard to quantify at this point, new policies will ultimately affect planning and operations for all aspects of the electric system—generation, transmission, and distribution.

Proponents of smart grid technology envision an array of active demand-side management methods that depend upon both programs with predictable energy savings, such as active load management systems and appliances, and applications with unpredictable results, such as real-time pricing and inclining block rate structures. It remains to be seen how much these systems will influence long-range load forecasts and the planning process. Although there is increasing pressure to reduce both capital expenditures and energy consumption, borrowers must ensure that the electrical network operates to certain standards under all conditions.

If there is a proliferation of distributed generation, future planning activities may have to address issues such as automation and control, communications, computing systems, and electronic security. While these concepts are likely several years from materially affecting distribution system long-range planning practices, it is important to be aware of the potential impact and monitor developments.

Appendix 4 of this *Guide* provides detailed information about distributed generation applications in four categories—large-scale, medium-scale, small-scale, and residential/commercial solar photovoltaics (PV)—and discusses ways to include them in a system's long-range plan.

g Special Equipment Considerations

Electric distribution systems should evolve as new technology to improve system operations, reliability and efficiency becomes available. However, the long-range study is not the appropriate tool for analyzing new technology. Separate studies are needed to evaluate the capabilities of new equipment to improve system operations, reliability and efficiency, such as:

- Automated metering reading (AMR),
- Electronic and/or microprocessor relays and metering,
- Geographical information systems (GIS),
- Supervisory control and data acquisition (SCADA),
- Concrete and steel poles,
- Communication systems,
- Special sectionalizing equipment,
- Outage management systems,
- Computer software,
- Operational tools and
- Other smart grid technologies.

11 USE OF THE LONG-RANGE PLAN TO GUIDE SYSTEM CHANGES

When complete, the long-range plan provides a picture of the future electric system. It specifies line conductor sizes, primary voltages, and new delivery point locations;

addresses transmission needs; and provides a basis for the distribution system and power supplier to make sound decisions to satisfy long-range system needs.

The plan allows the borrower to evaluate proposed sites for future substations and transmission lines and to purchase right-of-way in advance if state statutes and corporate by-laws allow. This can result in significant cost savings, especially in high-growth areas.

It is important to review the plan any time major changes in the electric system are under consideration, particularly when developing construction work plans or acquiring new large loads.

The benefits gained from the planning process and implementation of the long-range plan will offset the costs of developing the plan and reduce the likelihood of the need for costly rebuilds.

12 POWER SUPPLY STUDIES

The economic analysis in the long-range plan and the selection of the preferred plan are based on estimated parameters for component costs and system fixed charges. It is necessary to conduct a power supply study (PSS) to develop specific, accurate cost estimates and to determine availability of land, including right-of-way, before a particular project can be included in the budget and construction can begin. Most power suppliers, including generation and transmission cooperatives, provide guidelines for conducting such studies before capital is committed for construction. The studies follow most of the same procedures and guidelines used in the long-range system study but are based on more accurate costs determined from actual design options and field reviews. In addition, a power supply study is limited to a small part of the overall electric system.

Sometimes the power supply study results in a conclusion and system approach that is different from the long-range plan. In this case, the power supply study should be adopted as an amendment to the long-range plan. If the results of power supply studies are frequently different from the long-range plan, it may indicate that it is time to develop a new plan.

13 PERIODIC DETERMINATION OF PLAN VALIDITY

A borrower should review its long-range plan on a regular basis by comparing basic data, design criteria, and assumptions with actual system experience in order to verify the plan’s continued validity. At a minimum, a system should review its plan prior to preparing a new construction work plan, and a faster-growing system should conduct an annual review. If actual experience deviates significantly from assumptions, it is time to devise a new plan.

The average life span of a long-range plan for a fast-growing system is five to seven years, seven to 10 years for a moderate-growth system, and 10 to 15 years for slow-growth systems. Regular review will ensure the plan remains valid and will also assist the borrower in determining the need for a new plan when revisions are no longer adequate. Events that necessitate revision or replacement of the long range plan include:

- Loads develop faster or slower than projected.
- Power suppliers change their plans and service policies.
- Transmission or substation additions which are not in the long-range plan are needed.
- Significant large loads are added to the system.
- Necessary rights-of-way cannot be obtained.
- Laws and/or ordinances, such as requirements for underground line construction, change.
- Changes in technology offer new benefits.

Even if no major changes are needed, numerous minor revisions may necessitate a new plan.

14 CONCLUSION

Every borrower should develop and periodically review a long-range plan for meeting the system's future needs. The borrower should create the plan through a structured process that includes consultation and coordination with key stakeholders, including its power supplier, and its lenders if appropriate.

The long-range plan estimates the systems future needs based on its approved load forecast, evaluates alternate plans for meeting those needs, identifies the preferred plan and alternate plans if needed based on cost and other considerations, and proposes a schedule for system upgrades, new construction and retirements to implement the plan.

Users of this guide are encouraged to look at additional supplemental documents which are Excel® 2010 Workbooks. They can be useful tools in the completion of a Long-Range System Study. A summary of those documents is given below:

1. LRPG Exhibit C, Fixed Charges Calculations;
2. LRPG Exhibit D, Radial Transmission Line Assessment;
3. LRPG Exhibit E, Conductor Life Analysis;
4. LRPG Exhibit G, Economic Plan Analyses;
5. LRPG Exhibit H, Sensitivity Analyses;
6. LRPG Exhibit K, RUS Long Range Plan Report Checklist (Form 260); and
7. LRPG Exhibit L, RUS Long Range Plan Report Summary (Form 261).

Documents 1–5 each have a "Use Narrative" explaining the use of the workbook and how the spreadsheet can be applied. Copies of the documents are included on the RUS website.

EXHIBIT A
SUMMARY OF DATA REQUIRED

The information listed below is considered to be the typical data needed by the distribution planner to complete a Long-Range Plan (LRP).

1. 10 years of year-end RUS Financial and Operating Report Electric Distribution (Formerly known as the Form 7).
2. System computer model data and system maps for base system conditions that are available.
3. GIS mapping system for peak load conditions, if available.
4. A copy of the most recently completed Operations and Maintenance Survey (RUS Form 300).
5. Loading conditions by line section for the most recent peak month conditions.
6. Historical growth factors for consumers, kWh usage, and kW demand.
7. Other peak system load data, including measured monthly peak substation loading and feeder peak currents from field ammeters or SCADA system datum.
8. Historical annual fixed rate charge for the past five years, at a minimum, using the fixed charge spreadsheet of this LRPG.
9. Annual fixed rate charges of the power supplier.
10. A current copy of Load Forecast, formerly called the Power Requirements Study.
11. System Engineering and Economic Criteria (update as required).
12. Current substation configurations, voltages, capacities, ownership, age, conditions, power transformer losses, expansion capabilities and limitations, etc.
13. The current system policy for primary conductor size use and why they were chosen.
14. The average costs of building the various size distribution lines on a dollar-per-mile basis in today’s dollars.
15. The average costs of building the various size and voltage class transmission lines.†
16. The average costs of building various size and voltage class substations.†
17. The average costs of building various size low-side switching structures on a per-bay basis.
18. A list of special, on-system, large power and growth loads, getting input from district managers (be sure to document those loads that are in the current LF and those that are not).
19. Current electric state territorial laws and the possibility for system annexation by a neighboring distributor.
20. Wholesale rate structures and special conditions, including any anticipated changes. Also identify inflation rate for wholesale power costs and determine current avoided costs in dollars per kilowatt-hour.†
21. Transmission line locations within the electric distributor’s service area, their conductor size and voltage class. Also identify potential substation sites by locating industrial parks and potential large power and residential growth areas.†
22. Employment and income sources, growth potentials, land terrain and uses, saturation areas, inflation rates, etc.
23. Determine how many copies of the LRP report will be needed, including a bound copy of the supporting data.

† May have to be provided by power supplier.

EXHIBIT B
SAMPLE ENGINEERING AND ECONOMIC CRITERIA

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

DISTRIBUTION COST ESTIMATES (Distributor)			Cost/Mile	
1ø	1/0 ACSR	=	\$20,000	per mile
2ø	1/0 ACSR	=	\$35,000	per mile
3ø	1/0 ACSR	=	\$42,000	per mile
3ø	3/0 ACSR	=	\$54,000	per mile
3ø	336 ACSR	=	\$65,000	per mile
3ø	336 ACSR Double Circuit	=	\$92,000	per mile
3ø	477 ACSR	=	\$70,000	per mile
3ø	477 ACSR Double Circuit	=	\$105,000	per mile
3ø	795 ACSR	=	\$121,000	per mile
1ø	1/0 AL URD	=	\$80,000	per mile
1ø	4/0 AL URD	=	\$85,000	per mile
3ø	1/0 AL URD	=	\$150,000	per mile
3ø	4/0 AL URD	=	\$175,000	per mile
3ø	350 AL URD	=	\$180,000	per mile
3ø	500 AL URD	=	\$185,000	per mile
3ø	1000 AL URD	=	\$190,000	per mile
3ø	1500 AL URD	=	\$200,000	per mile
1ø	25kV Reinsulation	=	\$5,100	per mile
2ø	25kV Reinsulation	=	\$5,900	per mile
3ø	25kV Reinsulation	=	\$8,200	per mile
1ø	500 kVA Step Transformers (Pad)	=	\$15,000	each
3ø	3000 kVA Step Transformers (Pad)	=	\$86,000	each
3ø	5000 kVA Step Transformers (Pad)	=	\$120,000	each
14.4-kV Transformer Replacement Cost		=	\$750	each
Transformer Change-Out Labor Costs		=	\$300	each

SUBSTATION COST ESTIMATES

3ø	Circuit Breaker or Recloser for Substation	=	\$22,000	per feeder

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

SUBSTATION COST ESTIMATES*1

CURRENT PROJECTS*2

Description	Transformer Size	# Feeder Bays	Cost	Comments
Uprate existing 46kV/12.5kV Substation A to 115kV/12.5kV	12/16/20 MVA	4	$1,200,000	TBC in 2008
Abandon existing 46kV/12.5kV Substation B and build new 115kV/12.5kV sub	12/16/20 MVA	4	$1,200,000	TBC in 2008
Build new 115kV/25kV Substation C	12/16/20 MVA	4	$1,200,000	TBC in 2008

EXISTING SUBSTATIONS

Power Transformers

Description	Existing Transformer Size	Proposed Transformer Size	Cost	Comments
Uprate existing transformer at Substation D	10/12.5 MVA	12/16/20 MVA	$700,000	
Uprate existing transformer at Substation E	10 MVA	12/16/20 MVA	$1,400,000	
Uprate existing transformer at Substation F	10/12.5 MVA	12/16/20 MVA	$700,000	
Uprate existing Substation C	1-10/16/20 MVA	2-12/16/20 MVA	$1,000,000	
Uprate existing Substation E	1-10/16/20 MVA	2-12/16/20 MVA	$1,200,000	

25 kV Conversion

Description	Cost	Comments
Uprate existing Substation D from 115kV/12.5kV to 115kV/25kV	$650,000	
Uprate existing Substation E from 115kV/12.5kV to 115kV/25kV*3	$650,000	
Uprate new Substation H from 115kV/12.5kV to 115kV/25kV	$700,000	

NEW SUBSTATIONS

Description	Transformer Size	# Feeder Bays	Cost	Comments
Build new 115kV/12.5kV sub	10/12.5 MVA	4	$1,400,000	
Build new 115kV/12.5kV sub	10/12.5 MVA	6	$1,472,000	
Build new 115kV/25kV sub	10/12.5 MVA	4	$1,425,000	
Build new 115kV/25kV sub	10/12.5 MVA	6	$1,497,000	
Build new 115kV/12.5kV sub	12/16/20 MVA	4	$1,450,000	
Build new 115kV/12.5kV sub	12/16/20 MVA	6	$1,522,000	
Build new 115kV/25kV sub	12/16/20 MVA	4	$1,475,000	
Build new 115kV/25kV sub	12/16/20 MVA	6	$1,547,000	

**1 Data provided by G&T*
**2 2007 Dollars*
**3 Credit of $169, 289 (per G&T) for existing power transformer at Substation E not included in cost estimate*
TBC=To Be Completed
NOTE: G&T would install a 2nd 20 MVA transformer in lieu of a 15/20/25 MVA unit.

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
(2007 DOLLARS)

TRANSMISSION COST ESTIMATES[*1]

115 kV Tap Point	=	$250,000
115 kV Transmission Line Cost per Mile	=	$350,000
115 kV Transmission Line (For Substation E)—0.7 mi.	=	$245,000
115 kV Transmission Line (Substation C to Substation F)—5 mi.	=	$1,750,000
115 kV Transmission Line (Substation D to Substation H)—3.75 mi.	=	$1,312,500

[*1] *Per G&T estimates*

ECONOMIC and BASE ASSUMPTIONS
(2007 BASIS)

	Power Distributor Elec. Coop. Name <u>Distribution</u>	**Power Supplier[*] G&T Name <u>Sub. / Trans.</u>**
Losses/kWh ($)	$0.0600	$0.0400
Present Worth Interest Rate (%)	6.00%	6.00%
Annual Fixed Charge (%)[**]	9.83%	10.50%
T&D O&M Costs (%)	6.23%	0.00%
Substation O&M Costs (%)	0.00%	0.00%
Inflation Rate (%)	3.50%	3.50%
Energy Inflation Rate (%)	6.00%	2.88%
Annual Delivery Point Charge ($)	–	–
Total Value of Distribution Plant (12/31/xx)	$70,123,456	

[*] *Data provided by G&T*
[**] *Interest, depreciation, taxes, and insurance only.*

SYSTEM DESIGN CRITERIA
Each alternative being evaluated will be designed utilizing the Engineering and Economic Criteria (EEC) from the most current Construction Work Plan. Each long-range plan will be designed to have approximately the same capacity by requiring that line regulators will not be required in the long-range load level, but will allow for one bank of line regulators when and if needed on interim load levels.

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC CRITERIA
LOADING AND OPTIONS

LOADING LEVELS*[1]

		Most Probable		
Load Levels	**Years**	**Summer Peak kW Demand**	**Winter Peak kW Demand**	**Total Consumers**
1	2006 (05/06) System (actual) =	97,848	113,139	27,263
2	2011 (10/11) System =	127,552	144,271	30,227
3	2015 (14/15) System =	137,846	155,914	32,360
4	2026 (25/26) System =	163,370	184,785	37,819
	2006 to 2026 Average Compound Growth Rate **=**	**2.60%**	**2.48%**	**1.65% per year**

		Extreme Weather		
Load Levels	**Years**	**Summer Peak kW Demand***[2]	**Winter Peak kW Demand**	**Total Consumers**
1	2006 (05/06) System (actual) =	97,848	113,139	27,263
2	2011 (10/11) System =	144,797	175,874	30,227
3	2015 (14/15) System =	157,398	191,519	32,360
4	2026 (25/26) System =	188,647	230,314	37,819
	2006 to 2026 Average Compound Growth Rate **=**	**3.34%**	**3.62%**	**1.65% per year**

*[1] *From 2007 Load Forecast*
*[2] *Recommended load levels for Long-Range System Study*

PLAN OPTIONS CONSIDERED*[3]

Plan A	No New Delivery Points Added and Distribution Lines to Remain at Current Voltage Levels
Plan B	No New Delivery Points Added and All Distribution Voltage Converted to 25 kV
Plan C	New Delivery Points Added and Distribution Lines Remain at Current Voltage Levels
Plan D	New Delivery Points Added and Distribution Voltage Converted to 25 kV
Plan D1	Like D, but Substation B added instead of Substation A
Plan D1A	Like D1, but Substation C served from G&T 115-kV transmission line.

*[3] *As decided by the cooperative, the power supplier, and/or RUS, as the case may be*

EXHIBIT C
RUS FIXED CHARGE RATE CALCULATION GUIDE

ABC ELECTRIC COOPERATIVE
City, State
LONG-RANGE PLAN

Following is some data to assist in the calculation of a Fixed Charge Rate. A fixed charge rate is composed of several factors: the costs of capital, operation and maintenance, taxes, insurance, and depreciation. Calculating the cost of insurance as a percentage of investment is difficult and the result makes little difference; therefore, it can be ignored for most applications. The fixed charge rate is not an exact figure, but an estimate which is dependent on the quality of the assumptions involved in its calculation.
Note: References to annual Financial and Operating Report Electric Distribution are based on the 2014 Revision of the report.

I. Cost of Capital

A. It is important to recognize the cost of capital, which is greater than the cost of debt. This is because there is a cost of member equity. The return on equity portion of this calculation can be figured in at least three ways. The Goodwin method includes the cycle of capital credits in calculating the return on equity. Or, one may adopt a return on equity that a state regulatory authority has declared to be adequate for electric utilities. Or a TIER-based calculation, such as that illustrated below, may be used.

B. Net TIER (Times Interest Earnings Ratio)
   1. For future projects, TIER should be selected in accordance with the owner's Equity Management Plan.
   2. For comparison, TIER for a past year could be calculated from data on the annual Form 7:

$$\text{TIER} = \frac{\text{Interest [Part A, line 15(b)]} + \text{Margins [Part A, line 28(b)]}}{\text{Interest [Part A, line 15(b)]}} = \frac{\$1{,}892{,}504 + \$1{,}625{,}723}{\$1{,}892{,}504} = \mathbf{1.859}$$

C. CAPITAL STRUCTURE
   1. For future projects, the debt ratio should be in accordance with the owner's Equity Management Plan. Line of credit or short-term borrowing should be taken into consideration in long-term financial decisions.
   2. For comparison, the debt and equity ratios for a past year could be calculated from data on the annual Form 7:

$$\text{Debt Ratio} = \frac{\text{LTD (Part C,line 41)}}{\text{LTD (Part C,line 41)} + \text{Tot. Marg. \& Eq. (Part C,line 36)}} = \frac{\$36{,}131{,}862}{\$36{,}131{,}862 + \$35{,}001{,}345} \times 100 = \mathbf{50.79\%}$$

$$\text{Equity Ratio} = \frac{\text{Tot. Marg. \& Eq. (Part C,line36)}}{\text{LTD (Part C,line 41)} + \text{Tot. Marg. \& Eq. (Part C,line 36)}} = \frac{\$35{,}001{,}345}{\$36{,}131{,}862 + \$35{,}001{,}345} \times 100 = \mathbf{49.21\%}$$

D. COST OF CAPITAL

1. For future projects the cost of debt should be estimated carefully, taking long-term trends into account. A suggested form would be:

	Proportion of Debt		Long Range Est. of Interest Rate		
RUS	70%	×	4.60%	=	3.22% (a)
Supplemental Lender	30%	×	6.00%	=	1.80% (b)
Cost of Debt = (a) + (b)				=	**5.02%**

2. In case one needs to calculate the embedded cost of debt for a past year, it can be calculated from the annual Form 7:

[Embedded cost of debt] $\frac{\text{Interest [Part A, line 15(b)]}}{\text{LTD [Part C, line 41]}} \times 100 = \frac{\$1{,}892{,}504}{\$36{,}131{,}862} \times 100 =$ **5.24%**

3. Weighted cost rate of debt:

Debt Ratio (from 1.C above)		Cost of Debt (from 1.D above)		
50.79	×	5.02	=	**2.55%** (CD)

4. Weighted cost of equity:

Equity Ratio (from 1.C above)		Cost of Debt (from 1.D above)		
49.21	×	5.02	=	**2.47 %** (CE)

5. Cost of capital:

Wtd. cost rate of Debt (from 1.D.3 above)		TIER (from 1.B above)		
2.55	×	1.86	=	**4.74 %** (CC)

II. Operation and Maintenance

A. For future projects, O&M should be selected to agree with the various plan alternatives. If a more costly alternative promises lower O&M, it should be reflected here.

B. For comparison, a historic distribution-plant O&M could be calculated by this form, with figures from the annual form 7:

	Part E line 15(e)		Part F line 7(a)		
Net Distribution Plant, annual Form 7, last year	$66,382,036	–	$	= $66,382,036	
Net Distribution Plant, annual Form 7, 2 years ago	$63,359,785	–	$	= $63,359,785	
Average Net Distribution Plant last year				= $64,870,911 (a)	
Distribution Operations: Part A, line 5(b):				= $ 2,636,701 (b)	
Distribution Maintenance: Part A, line 6(b):				= $ 2,072,182 (c)	
O&M as % of Avg. Net Dist. Plant [(b) + (c)] / (a) × 100; or estimated from II.A., above				$4,708,883	**7.26%** (O&M)

III. Taxes

Property tax: annual Form 7, last year, Part A, line 13(b)	$ —	
Other tax: annual Form7, last year, Part A, line 14(b)	$ 4,653	
Total taxes paid on plant	$ 4,653 (a)	
Plant the taxes were paid on: Net Utility Plant, annual Form 7, 2 years ago, Part C, line 5	$ 54,849,072	
+ Materials and Supplies, annual Form 7, 2 years ago, Part C, line 22	$ 847,091	
	$ 55,696,163 (b)	**0.0084 %** (Tx)
Tax Rate: [(a)/(b)] x 100, or estimated future tax rate		

IV. Depreciation

Use an appropriate depreciation figure for the projected alternative(s) being studied. Most owners use straight-line depreciation where the depreciation rate is the reciprocal of the asset's life.

Annual rate for the coop, for plant or for classes of plant **3.24%** (Dep)

V. Total Annual Fixed Charge Rate

= Cost of Capital (CC) + Oper. & Main. (O&M) + Taxes (Tx) + Depreciation (Dep) = **15.25%**

VI. Modified Tier (Net TIER less G&T Capital Credits)

$$\text{Modifed TIER} = \frac{\text{Interest [Part A, line 15(b)] + Margins [Part A, line 28(b)] - G\&T CC [Part A, line 25(b)]}}{\text{Interest [Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 - \$833{,}883}{\$1{,}892{,}504} = \mathbf{1.4184}$$

VII. Debt Service Coverage (DSC) Ratio

$$\text{DSC} = \frac{\text{Interest [Part A, line 15(b)] + Margins [Part A, line 28(b)] + Dep. [Part A, line12 (b)]}}{\text{Total Debt Service = Principal [Part O, line 13(c)] + Interest [Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 + \$2{,}387{,}846}{\$1{,}307{,}936 + \$1{,}892{,}504} = \mathbf{1.85}$$

VIII. Modified Debt Service Coverage (DSC) Ratio

Modified DSC =

$$\frac{\text{Interest [Part A, line 15(b)] + Margins [Part A, line 28(b)] + Dep. [Part A, line 12(b)] – G\&T CC [Part A, line 25(b)]}}{\text{Debt Service [Part O, line 13(c)] + [Part A, line 15(b)]}}$$

$$= \frac{\$1{,}892{,}504 + \$1{,}625{,}723 + \$2{,}387{,}846 - \$833{,}883}{\$1{,}307{,}936 + \$1{,}892{,}504} = \mathbf{1.58}$$

IX. Plant Revenue Ratio (PRR)

$$\text{PRR} = \frac{\text{Total Utility Plant [Part C, line 3]}}{\text{Elec. Revenue [Part R, line 12+13] – Power Cost [Part L, line 5(d)]}} = \frac{\$79{,}937{,}007}{\$43{,}400{,}629 - \$28{,}742{,}748} = \mathbf{5.45}$$

ABC ELECTRIC COOPERATIVE
City, State
SUMMARY RUS FIXED CHARGE RATE PROJECTIONS

TOTAL ANNUAL FIXED CHARGE RATE

Year	Cost Debt (CD)		TIER		Cost Capital (CC)	Operation Maintenance (O&M)	Taxes (Tx)	Depreciation (Dep)	(TFCR)
2002	2.24%	×	2.6218	=	5.87%	6.39%	0.00%	3.24%	15.50%
2003	2.49%	×	2.2376	=	5.57%	6.08%	0.00%	3.24%	14.88%
2004	2.59%	×	1.6704	=	4.32%	6.21%	0.00%	3.24%	13.77%
2005	2.58%	×	2.0150	=	5.20%	6.44%	0.00%	3.24%	14.87%
2006	2.55%	×	1.8590	=	4.74%	7.26%	0.01%	3.24%	15.25%
Projected	2.49%		2.0808		5.14%	6.48%	0.00%	3.24%	14.86%

TFCR = Cost of Capital (CC) + Oper. & Main. (O&M) + Taxes (Tx) + Depreciation (Dep)

KEY RATIOS

Year	TIER	Modified TIER	Debt Ratio	Equity Ratio	DSC	Modified DSC	Plant Revenue Ratio
2002	2.62	2.43	44.57%	55.43%	2.48	2.36	5.22
2003	2.24	1.94	49.57%	50.43%	2.10	1.93	5.25
2004	1.67	1.50	51.53%	48.47%	1.75	1.65	5.66
2005	2.02	1.72	51.40%	48.60%	1.94	1.76	5.39
2006	1.86	1.42	50.79%	49.21%	1.85	1.58	5.45
Projected	2.08	1.80	49.57%	50.43%	2.02	1.86	5.40

EXHIBIT D
RADIAL TRANSMISSION LINE RELIABILITY AND OPERATIONAL ASSESSMENT

Radial Transmission Line (RTL) Characteristics: RTL #: ABC25

Name and Description: Southport to Wewa 115 kV

Operating Voltage (kV): *115* *Conductor Size & Type:* *397ACSR (Ibis)*

Right-of-Way Width (feet): *100* *Radial Distance (miles):* *33.5*

Last Peak Load (MW): *18.7* *Peak Time (month, year):* *Jul-09*

Load Distance Service Factor (MW-Miles):[A] *626* *Year Built:* *1985*

With loss of the RTL, what % of load can existing distribution ties support? *None*

Major Line Maintenance Cycle Years: *15*

Year of Last Major Line Maintenance: *2002*

Right-of-Way Location (cross-country, roadside, etc.): *Cross Country; Swamp; Water*

Right-of-Way Maintenance Cycles (years): *5*

Frequency of Right-of-Way (years):

Inspections *Annually* *Mowing/Spraying* *5*

Danger Tree Removal *As Required* *Side Trimming* *10*

Transmission Line Provider: ABC G&T

Impacted Distributors or Cooperatives: XYZ Cooperative Only

RTL Reliability and Operational Questions[B]	**No**	**Yes**
1. *Does the RTL have a high Load Distance Service Factor (LDSF) greater than 150 megawatt-miles?*		X
2. *Is the RTL poorly accessible as determined by the Owner during all or part of the year?*		X
3. Does the RTL serve a delivery point that provides power to high priority loads (e.g., hospitals, manufacturing parks, airports, commercial loads, etc.)?	X	
4. *Is the conductor in deteriorated condition based on recent sample testing?*	X	
5. *Is the RTL condition contributed to more than three sustained outages over the last two years?*		X
6. *Has there been an outage over four hours in the past five years attributed to the RTL (excluding those during a major storm)?*		X
7. *Is the RTL in the power supplier's top 5% of most unreliable lines?*		X
8. *Does the RTL owner have any major improvement plans in the near future or in the general area of the distributor/cooperative substation?*		X
9. *Is the RTL operating at 69 kV or less and have a >50% of the conductor published full load amperes for the projected long-range peak loading conditions?*	X	
Number "Yes" Responses[C] =		6

RTL PLANNING COMMITMENT

Based on the above assessment, the electric system distribution engineer has decided that the referenced RTL _X_ ***is*** or _____ ***is not*** to be included in the new electric system long-range plan. A copy of this assessment and commitment is to be supplied to the RTL provider indicated above.

Signature: Alfred E. Newman

Distributor's Planning Engineer Name: Alfred E. Newman, P.E.

Distributor's Planning Engineer Title: Manager of E&O, XYZ Cooperative

[A] Load Distance Service Factor = (Latest Peak Demand Load Served) × (Radial Line Distance)
[B] Categories shown in italics are to be answered by the RTL Owner and Provider, if applicable.
[C] RTLs that have a number of "affirmative" responses to the reliability and operational questions above should be included in the long-range planning process.

EXHIBIT E
SAMPLE ECONOMIC CONDUCTOR LIFE SYSTEM ANALYSIS

ABC ELECTRIC COOPERATIVE
CITY, STATE
2008 LONG-RANGE PLAN

CONDUCTOR LIFE CYCLE ANALYSIS
(NEW CONSTRUCTION LEGEND AND INPUT VALUES)

0.00%	TOTAL	Total fixed cost. This is an optional replacement for O&M + TAX + DEP + INS.

6.23%	O&M	Operations and Maintenance Expense as a percentage of Average Net Distribution *Plant calculated using RUS Bulletin 1724D-101A,* ***Electric System Long-Range Planning Guide****, based on RUS Fixed Charge Calculation Guide*
0.00%	TAX	Property tax: annual Form 7, last year Part A, line 13(b) *Plant the taxes were paid on: annual Form 7, 2 years ago, Part C, line 5 + line 22* *Tax Rate: (Property tax / Plant) x 100, or estimated future tax rate*
3.24%	DEP	Most Owners use straight-line depreciation where the depreciation rate is the reciprocal of the asset's life. Use annual rate for Co-op, for classes of plant Depreciation rate on RUS Form 7 Part E Lines 5(f) and line 6(f)
0.00%	INS	Insurance as a percentage of Net Distribution Plant. *Calculating the cost of insurance as a percentage of investment is difficult, and the result makes little difference, therefore, it can be ignored for most applications.*

3.50%	INF	The annual inflation rate
30	m	The loan amortization period in years
7.2&14.4	KV	Line-to-ground voltage in kV
99.00%	PF	Peak month power factor
6.59%	INT	Cost of Capital (Calculated using *RUS Fixed Charge Guide*) used for Present Worth Calculation
2.60%	LGR	The annual rate of growth projected for the peak demand (use latest PRS)
30	ULC	Useful Life of Conductor
$0.00	$/kW	Monthly demand charge in dollars per kW per month. If $/kW is zero, the following dependent inputs will also be zero:

0.00%	kWI	Demand charge inflation rate
0.00%	CF	Coincidence factor (this factor represents the coincidence between the non-coincident peak for the line and billing demand)
0.000	RMO	The number of months the metered demand exceeds the minimum billing demand
0.000	RAT	The annual demand ratchet expressed as a decimal
0.000	N	The ratio of the average of the squares of the monthly kW demands for the months when the metered demand exceeds the minimum billing demand to the square of the peak month demand

$0.0689	$/kWh	Energy charge in dollars per kWh per month
6.00%	kWhI	Energy charge inflation rate
43.70%	LF	Annual load factor

ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS

7.2 kV
Summary

	Initial Loading			**Future Loading Based on a 2.60% LGR for 30 Years**	
For loads below	1,378 kW	use	1/0 ACSR	2,976	kW
For loads between	1,378 kW and 1,423 kW	use	3/0 ACSR	2,976	kW
For loads between	1,423 kW and 1,779 kW	use	336 ACSR	3,073	kW
For loads between	1,779 kW use 5,823 kW	use	477 ACSR	3,842	kW
For loads above	5,823 kW	use	795 ACSR	12,577	kW

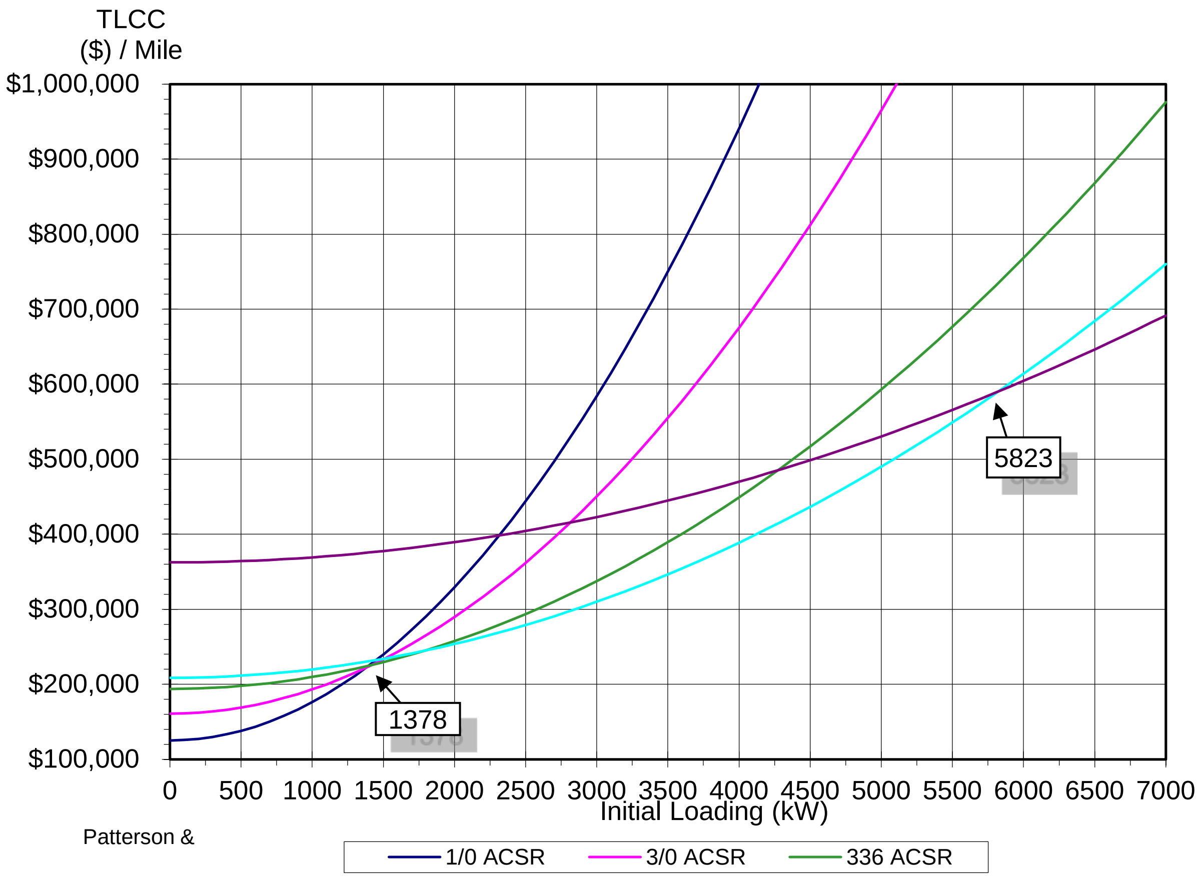
Construction Costs

			Conductor Operating Capacity*		
Conductor	Cost Per Mile	Ohms Per Mile†	100%	50%	
3 Ø 1/0 ACSR	$42,000	0.888	4,918	2,459	kW
3 Ø 3/0 ACSR	$54,000	0.560	7,271	3,635	kW
3 Ø 336 ACSR	$65,000	0.278	11,334	5,667	kW
3 Ø 477 ACSR	$70,000	0.196	14,327	7,164	kW
3 Ø 795 ACSR	$121,600	0.117	19,246	9,623	kW

† Resistance based on conductor operating temperature of 25°C (77°F) for Winter Loading.

* 100% Conductor Operating Capacity based on conductor temperature of 75°C (167°F), with a 25°C (77°F) ambient, with a and a 2 ft./sec wind, frequency = 60 Hz. Per *Westinghouse T&D Reference Book*, East Pittsburgh, Pa. (4th Edition: 11th Printing), 1950.

ABC ELECTRIC COOPERATIVE PLAN
CONDUCTOR LIFE CYCLE ANALYSIS
Total Life Cycle Cost — Three-Phase 7.2 kV



ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS

14.4 kV
Summary

	Initial Loading			Future Loading based on a 2.60% LGR for 30 Years	
For loads below	2,756 kW	use	1/0 ACSR	5,953	kW
For loads between	2,756 kW and 2,846 kW	use	3/0 ACSR	5,953	kW
For loads between	2,846 kW and 3,559 kW	use	336 ACSR	6,147	kW
For loads between	3,559 kW use 11,647 kW	use	477 ACSR	7,687	kW
For loads above	11,647 kW	use	795 ACSR	25,156	kW

Construction Costs

			Conductor Operating Capacity*		
Conductor	Cost Per Mile	Ohms Per Mile	100%	50%	
3 Ø 1/0 ACSR	$42,000	0.888	9,837	4,918	kW
3 Ø 3/0 ACSR	$54,000	0.560	14,541	7,271	kW
3 Ø 336 ACSR	$65,000	0.278	22,667	11,334	kW
3 Ø 477 ACSR	$70,000	0.196	28,655	14,327	kW
3 Ø 795 ACSR	$121,600	0.117	38,491	19,246	kW

† Resistance based on conductor operating temperature of 25°C (77°F) for Winter Loading.

* 100% Conductor Operating Capacity based on conductor temperature of 75°C (167°F), with a 25°C (77°F) ambient, with a and a 2 ft./sec wind, frequency = 60 Hz. Per *Westinghouse T&D Reference Book*, East Pittsburgh, Pa. (4th Edition: 11th Printing), 1950.

ABC ELECTRIC COOPERATIVE
CONDUCTOR LIFE CYCLE ANALYSIS
Total Life Cycle Cost — Three-Phase 14.4 kV

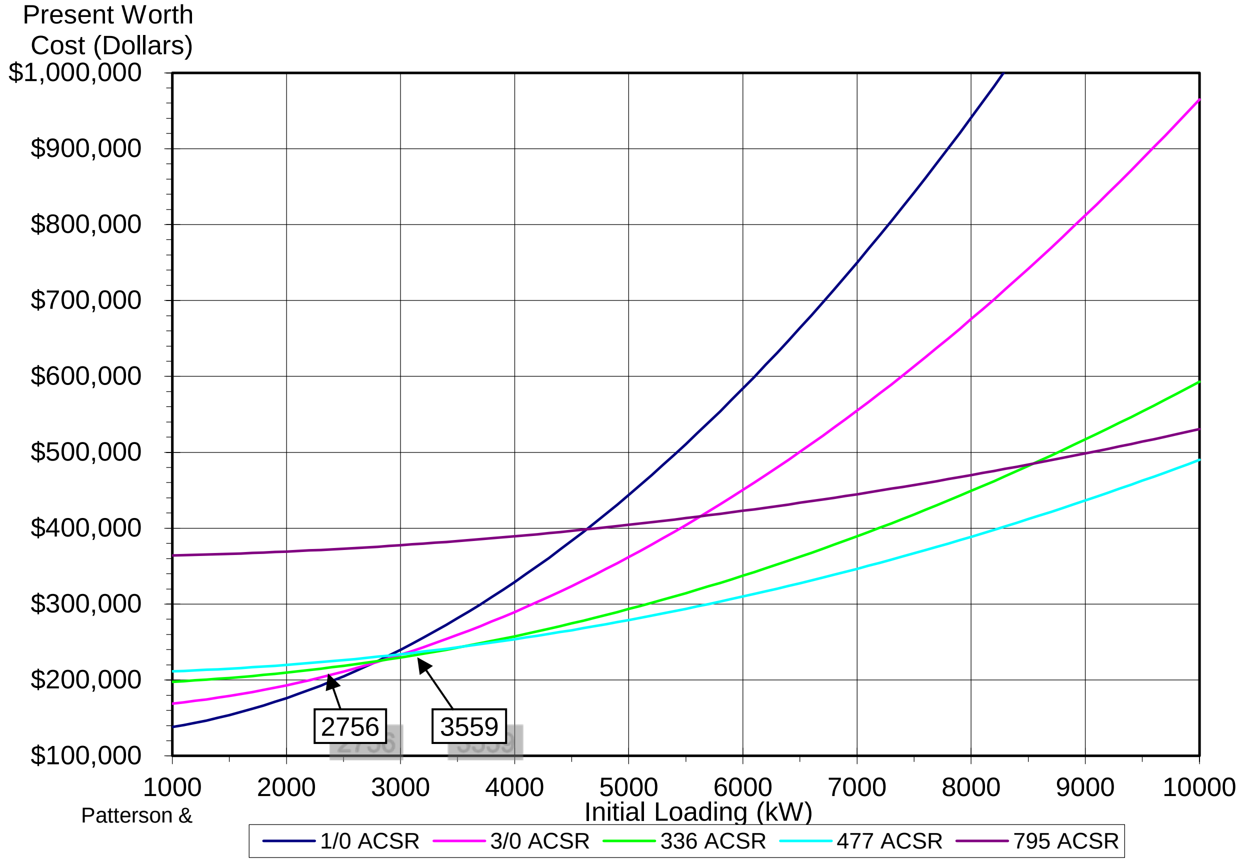


EXHIBIT F
SAMPLE SUBSTATION LOADING SHEET FOR SPECIFIC PLAN

ABC Electric Cooperative
City, State
2008 LONG-RANGE PLAN
SUBSTATION LOAD DATA
Plan D1 (Preferred Plan)

							SUBSTATION DEMANDS																				
No.	Substation Name	Voltage kV	Xfmr Qty. Size MVA	Existing Capacity	Proposed Capacity	% Loaded 2006	Summer 2006 kW	2007 kW	2008 kW	2009 kW	2010 kW	LL2 2011 kW	2012 kW	2013 kW	2014 kW	LL3 2015 kW	2016 kW	2017 kW	2018 kW	2019 kW	2020 kW	2021 kW	2022 kW	2023 kW	2024 kW	2025 kW	LL4 2026 kW
1	Substation A	115-25	1-10/12.5				8,073	8,501	8,951	9,426	9,925	10,451	11,005	11,236	11,472	11,713	11,877	12,044	12,212	12,383	12,557	12,732	12,911	13,091	13,275	13,461	13,649
	(- Substation O)											- 3,799	- 4,000	- 4,084	- 4,170	- 4,257	- 4,317	- 4,377	- 4,439	- 4,501	- 4,564	- 4,628	- 4,692	- 4,758	- 4,825	- 4,892	- 4,961
	Total	115-25	1-10/12.5	12,500	12,500	65%	8,073	8,501	8,951	9,426	9,925	6,652	7,005	7,152	7,302	7,456	7,560	7,667	7,773	7,882	7,993	8,104	8,219	8,333	8,450	8,569	8,688
2	Substation B	115-12.5	1-10/12.5				4,441	4,676	4,924	5,185	5,460	5,749	6,054	6,181	6,311	6,444	6,534	6,625	6,718	6,812	6,907	7,004	7,102	7,202	7,302	7,405	7,508
	Substation J												- 750														
	Total	115-12.5	1-10/12.5	12,500	12,500	36%	4,441	4,676	4,924	5,185	5,460	5,749	5,304	6,181	6,311	6,444	6,534	6,625	6,718	6,812	6,907	7,004	7,102	7,202	7,302	7,405	7,508
3	Substation C	115-25	1-10/12.5				9,533	10,038	10,570	11,131	11,720	12,342	12,996	13,269	13,547	13,832	14,025	14,222	14,421	14,623	14,827	15,035	15,246	15,459	15,675	15,895	16,117
	(-switching w/ Substation F)							- 150	- 158	- 166	- 175	- 184	- 194	- 198	- 202	- 207	- 210	- 213	- 215	- 219	- 222	- 225	- 228	- 231	- 234	- 238	- 241
	Substation F												- 1,800														
	Substation D												- 250														
	(- Substation O)											- 3,514	- 3,700	- 3,778	- 3,857	- 3,938	- 3,993	- 4,049	- 4,106	- 4,163	- 4,222	- 4,281	- 4,341	- 4,401	- 4,463	- 4,525	- 4,589
	Total	115-25	1-10/12.5	12,500	12,500	76%	9,533	9,888	10,412	10,965	11,545	8,644	7,052	9,293	9,488	9,687	9,822	9,960	10,100	10,241	10,383	10,529	10,677	10,827	10,978	11,132	11,287
4	Substation D	115-25	1-12/16/20				12,079	12,673	13,444	14,262	15,130	16,053	17,032	17,458	17,894	18,342	18,635	18,933	19,236	19,544	19,857	20,174	20,497	20,825	21,158	21,497	21,841
	(- Substation N)									- 1,970	- 2,074	- 2,184	- 2,300	- 2,348	- 2,398	- 2,448	- 2,482	- 2,517	- 2,552	- 2,588	- 2,624	- 2,661	- 2,698	- 2,736	- 2,774	- 2,813	- 2,852
	(- Substation N)																							- 1,023	- 1,041	- 1,059	- 1,078
	(- Substation P)																							- 5,582	- 5,679	- 5,779	- 5,880
	Substation C												250														
	Total	115-25	1-12/16/20	20,000	20,000	60%	12,079	12,673	13,444	12,292	13,056	13,869	14,942	15,110	15,496	15,894	16,153	16,416	16,684	16,956	17,233	17,513	17,799	11,484	11,664	11,846	12,031
5	Substation E (old)	46-12.5	3-1.917				4,604	4,848	5,105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(-load to Substation E (new)) [*1]								- 5,105	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total	46-12.5	3-1.917	5,750	5,750	80%	4,604	4,848	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Substation E (new)	46-12.5	1-12/16/20					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation E (old) [*1]								5,105	5,376	5,660	5,960	6,050	6,177	6,307	6,439	6,529	6,621	6,713	6,807	6,903	6,999	7,097	7,197	7,298	7,400	7,503
	+load from Substation K[*1]								2,943	3,099	3,263	3,436	3,500	3,574	3,649	3,725	3,777	3,830	3,884	3,938	3,993	4,049	4,106	4,163	4,222	4,281	4,341
	(-load to Substation M)[*1]								- 825	- 869	- 915	- 963	- 1,500	- 1,532	- 1,564	- 1,596	- 1,619	- 1,642	- 1,664	- 1,688	- 1,711	- 1,735	- 1,760	- 1,784	- 1,809	- 1,835	- 1,860
	Total	46-12.5	1-12/16/20	0	20,000	0%		0	7,223	7,606	8,008	8,433	8,050	8,219	8,392	8,568	8,687	8,809	8,933	9,057	9,185	9,313	9,443	9,576	9,711	9,846	9,984
6	Substation F	46-25	3-1.250				2,662	2,803	2,952	3,108	3,273	3,446	3,629	3,705	3,783	3,862	3,916	3,971	4,027	4,083	4,140	4,198	4,257	4,317	4,377	4,438	4,501
	+switching w/ Substation F							150	158	166	175	184	250	255	261	266	270	274	277	281	285	289	293	297	302	306	310
	LP18 - existing prison[*2]						0	1,000	1,500	2,000	2,000	2,000	2,100	2,205	2,315	2,431	2,553	2,680	2,814	2,955	3,103	3,258	3,421	3,592	3,771	3,960	4,158
	LP23 - new prison[*2]						0	0	0	0	1,500	1,500	1,575	1,654	1,736	1,823	1,914	2,010	2,111	2,216	2,327	2,443	2,566	2,694	2,828	2,970	3,118
	Total	46-25	3-1.250	3,750	20,000	71%	2,662	3,953	4,610	5,274	6,948	7,130	7,554	7,819	8,095	8,382	8,653	8,935	9,229	9,535	9,855	10,188	10,537	10,900	11,278	11,674	12,087
7	Substation G	115-12.5	1-10				7,407	7,898	8,422	8,980	9,575	10,210	10,200	10,468	10,744	11,026	11,219	11,415	11,615	11,818	12,025	12,236	12,450	12,668	12,889	13,115	13,344
	uprate in 2011																										
	Total	115-12.5	1-10	10,000	20,000	74%	7,407	7,898	8,422	8,980	9,575	10,210	10,200	10,468	10,744	11,026	11,219	11,415	11,615	11,818	12,025	12,236	12,450	12,668	12,889	13,115	13,344
8	Substation H	115-25	1-10/12.5				10,946	11,672	12,446	13,271	14,151	15,089	15,100	15,497	15,905	16,323	16,609	16,899	17,195	17,496	17,802	18,114	18,431	18,753	19,081	19,415	19,755
	(- Substation Q)																				- 3,563	- 3,625	- 3,689	- 3,753	- 3,819	- 3,886	- 3,954
	Total	115-25	1-10/12.5	12,500	20,000	88%	10,946	11,672	12,446	13,271	14,151	15,089	15,100	15,497	15,905	16,323	16,609	16,899	17,195	17,496	14,239	14,489	14,742	15,000	15,262	15,529	15,801
9	Substation I	115-25	1-10/12.5				9,451	10,078	10,746	11,458	12,218	13,028	13,892	14,257	14,632	15,017	15,280	15,547	15,819	16,096	16,378	16,664	16,956	17,253	17,554	17,862	18,174
	(- Substation N)									- 5,650	- 6,025	- 6,424	- 6,850	- 7,030	- 7,215	- 7,405	- 7,534	- 7,666	- 7,800	- 7,937	- 8,076	- 8,217	- 8,361	- 8,507	- 8,656	- 8,808	- 8,962
	(- Substation P)																							- 4,770	- 4,854	- 4,939	- 5,025
	Total	115-25	1-10/12.5	12,500	12,500	76%	9,451	10,078	10,746	5,808	6,193	6,604	7,042	7,227	7,417	7,612	7,746	7,881	8,019	8,159	8,302	8,447	8,595	3,976	4,044	4,115	4,187
10	Substation J	115-25	1-12/16/20				12,349	13,051	13,833	14,661	15,541	16,473	17,462	17,899	18,346	18,805	19,106	19,411	19,722	20,037	20,358	20,684	21,015	21,351	21,692	22,040	22,392
	(- Substation O)											- 4,274	- 4,500	- 4,595	- 4,691	- 4,789	- 4,857	- 4,925	- 4,993	- 5,063	- 5,134	- 5,206	- 5,279	- 5,353	- 5,428	- 5,504	- 5,581
	Total	115-25	1-12/16/20	20,000	20,000	62%	12,349	13,051	13,833	14,661	15,541	12,199	12,962	13,304	13,655	14,016	14,249	14,486	14,729	14,974	15,224	15,478	15,736	15,998	16,264	16,536	16,811
11	Substation K	46-12.5	3-2.5				3,606	3,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(-Substation K Abandoned)								- 3,797																		
	Total	46-12.5	3-2.5	7,500	7,500	48%	3,606	3,797	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Substation L	115-12.5	1-12/16/20				11,667	12,441	13,265	14,145	15,083	16,083	16,800	17,242	17,695	18,161	18,478	18,802	19,131	19,466	19,806	20,153	20,506	20,864	21,230	21,601	21,979
	+load from Substation K[*1]								0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	(- Substation L 25kV 25kV)										-12,543	-13,374	-14,261	-14,636	-15,021	-15,416	-15,686	-15,960	-16,240	-16,524	-16,813	-17,107	-17,407	-17,711	-18,021	-18,337	-18,657
	Total	115-12.5	1-12/16/20	12,500	20,000	93%	11,667	12,441	13,265	14,145	2,540	2,709	2,539	2,606	2,674	2,745	2,792	2,842	2,891	2,942	2,993	3,046	3,099	3,153	3,209	3,264	3,322
12	Substation L 25kV 25kV	115-25	1-12/16/20				0				12,543	13,374	14,261	14,636	15,021	15,416	15,686	15,960	16,240	16,524	16,813	17,107	17,407	17,711	18,021	18,337	18,657
	(-Substation Q)																				- 1,247	- 1,269	- 1,291	- 1,314	- 1,337	- 1,360	- 1,384
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	12,543	13,374	14,261	14,636	15,021	15,416	15,686	15,960	16,240	16,524	15,566	15,838	16,116	16,397	16,684	16,977	17,273
13	Substation M	46-12.5	3-.833				2,354	2,479	2,610	2,748	2,894	3,048	3,209	3,276	3,345	3,415	3,463	3,512	3,561	3,611	3,661	3,713	3,765	3,817	3,871	3,925	3,980
	+load from Substation E (old)[*1]								825	869	915	963	850	868	886	905	917	930	943	956	970	983	997	1,011	1,025	1,040	1,054
	Total	46-12.5	3-.833	2,500	20,000	94%	2,354	2,479	3,435	3,617	3,809	4,011	4,059	4,144	4,231	4,320	4,380	4,442	4,504	4,567	4,631	4,696	4,762	4,828	4,896	4,965	5,034
14	Substation N	115-25	1-12/16/20				0	0	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100
14	Substation N - 2nd Transformer	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation I									5,050	5,384	5,741	5,800	5,953	6,109	6,270	6,379	6,491	6,605	6,720	6,838	6,958	7,079	7,203	7,329	7,458	7,588
	+load from Substation D									1,970	2,074	2,184	2,000	2,042	2,085	2,129	2,158	2,189	2,219	2,250	2,282	2,314	2,346	2,379	2,412	2,446	2,480
	+load from Substation D																							1,023	1,041	1,059	1,078
	(-load to Substation P)																							- 2,106	- 2,143	- 2,181	- 2,219
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	7,020	7,458	7,925	7,800	7,995	8,194	8,398	8,537	8,680	8,824	8,970	9,120	9,272	9,425	8,499	8,639	8,782	8,927
15	Substation O	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation A											3,086	3,200	3,267	3,336	3,406	3,454	3,502	3,551	3,601	3,651	3,702	3,754	3,807	3,860	3,914	3,969
	+load from Substation C											3,514	3,200	3,267	3,336	3,406	3,454	3,502	3,551	3,601	3,651	3,702	3,754	3,807	3,860	3,914	3,969
	+load from Substation J											3,751	3,600	3,676	3,753	3,832	3,885	3,940	3,995	4,051	4,107	4,165	4,223	4,282	4,342	4,403	4,465
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	10,351	10,000	10,210	10,425	10,644	10,793	10,944	11,097	11,253	11,409	11,569	11,731	11,896	12,062	12,231	12,403
16	Substation P	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation D																							5,582	5,679	5,779	5,880
	+load from Substation I																							4,770	4,854	4,939	5,025
	+load from Substation N																							2,106	2,143	2,181	2,219
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,458	12,676	12,899	13,124
17	Substation Q	115-25	1-12/16/20				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	+load from Substation L 25kV 25kV																				1,247	1,269	1,291	1,314	1,337	1,360	1,384
	+load from Substation H																				3,563	3,625	3,689	3,753	3,819	3,886	3,954
	Total	115-25	1-12/16/20	0	20,000	0%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4,810	4,894	4,980	5,067	5,156	5,246	5,338
	System Total			144,500	343,250	69%	99,172	105,955	127,811	134,350	142,852	149,049	149,970	155,961	159,450	163,031	165,520	168,061	170,651	173,286	175,975	178,716	181,513	184,362	187,264	190,231	193,249

EXHIBIT G
SAMPLE PLAN ECONOMIC ANALYSIS SPREADSHEET

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLANS A, B, C, D, D1, D1A
Assumptions: See Detail Plan Analysis

Number of Years for This Comparison: 18

FIRST YEAR OF STUDY 2008

	Power Distributor	Power Supplier
1. Energy Cost/kWh ($)	$0.0689	$0.04300
2. Present Worth Interest Rate (%)	6.00%	6.00%
3. Annual Fixed Charge (%)	9.83%	10.50%
4. T&D O&M Costs (%)	6.23%	0.00%
5. Substation O&M Costs (%)	0.00%	0.00%
6. Inflation Rate (%)	3.50%	3.50%
7. Energy Inflation Rate (%)	6.00%	2.88%
8. Additional Delivery Point Charge ($)		—
9. Percent of Dist. Line Insulated for 25kV	0%	

Note: Annual Fixed Charge only includes interest, depreciation, taxes, and insurance rates.
O&M costs inflate with Inflation Rate.
Energy costs inflate with Energy Inflation Rate.

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
ECONOMIC COMPARISONS
(2008 DOLLARS)

PLAN SUMMARY

Plan A	No New Delivery Points Added and Distribution Lines to Remain at Current Voltage Levels
Plan B	No New Delivery Points Added and All Distribution Voltage Converted to 25 kV
Plan C	New Delivery Points Added and Distribution Lines Remain at Current Voltage Levels
Plan D	New Delivery Points Added and Distribution Voltage Converted to 25 kV
Plan D1	Like D, but Substation B Added Instead of Substation A
Plan D1A	Like D1, but Substation C Served from G&T 115-kV Transmission Line

PRESENT WORTH ECONOMIC ANALYSIS

	G&T Power Supplier	Wheeling Costs	ABC EC Power Distributor	Distributor Losses at Distributor Cost	Distributor Losses at Supplier Cost	One Ownership	Preferred Plan Cost Difference
Plan A	$16,548,914	$11,448,005	$18,372,961	*$10,862,380*	$5,167,561	$51,537,441	$1,494,069
Plan B	$17,455,913	$11,448,005	$23,150,650	*$9,775,706*	$4,684,871	$56,739,439	$6,696,067
Plan C	$17,777,867	$12,095,507	$16,677,014	*$10,486,111*	$5,000,427	$51,550,815	$1,507,443
Plan D*1	$18,959,550	$11,646,030	$14,680,545	*$9,858,514*	$4,721,654	$50,007,779	($35,593)
Plan D1	$20,207,558	$9,922,383	$15,267,278	*$9,688,539*	$4,646,153	$50,043,372	$0
Plan D1A	$22,301,687	$8,374,892	$15,267,278	$9,688,539	$4,646,153	$50,590,010	$546,638

CONSTRUCTION COSTS AND LOSSES SUMMARY

	G&T Power Supplier Costs	Wheeling Costs	ABC EC Power Distributor Costs	Total Costs	ABC EC Power Distributor Losses	Total Cost of Construction and Losses	Preferred Plan Cost Difference
Plan A	$14,648,138	$19,381,592	$18,217,063	$52,246,793	$10,862,380	$63,109,173	$180,212
Plan B	$16,128,849	$19,381,592	$22,958,945	$58,469,386	$9,775,706	$68,245,092	$5,316,131
Plan C	$15,268,138	$20,863,794	$16,501,473	$52,633,405	$10,486,111	$63,119,516	$190,555
Plan D	$17,248,849	$19,957,572	$16,263,577	$53,469,998	$9,858,514	$63,328,512	$399,551
Plan D1	$19,811,349	$16,545,686	$16,883,387	$53,240,422	$9,688,539	$62,928,961	$0
Plan D1A	$21,811,349	$13,835,086	$16,883,387	$52,529,822	$9,688,539	$62,218,361	($710,600)

Note: Highlight indicates the Preferred Plan. The Preferred Alternate Plan is Plan D1A.
*1 Due to operational reasons, this plan is not considered a viable option.

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

Number of years for this comparison: 18
MAXIMUM YEARS = 30

	Power Distributor	Energy Supplier
1. Energy Cost/kWh ($)	$0.0689	$0.0430
2. Present Worth Interest Rate (%)	6.00%	6.00%
3. Annual Fixed Charge (%)	9.83%	10.50%
4. T&D O&M Costs (%)	6.23%	0.00%
5. Substation O&M Costs (%)	0.00%	0.00%
6. Inflation Rate (%)	3.50%	3.50%
7. Energy Inflation Rate (%)	6.00%	2.88%
8. Annual Delivery Point Charge ($)	—	

Note: Annual Fixed Charge only includes interest, depreciation, taxes, and insurance rates.
O&M costs inflate with Inflation Rate.
Energy costs inflate with Energy Inflation Rate.

Cost Summary—Present Worth Dollars

	Power Supplier	Power Distributor	One Ownership
Transmission & Substation	$20,207,558	—	$20,207,558
Substation & Distribution	—	$15,267,278	15,267,278
Subtotal	20,207,558	15,267,278	35,474,836
Delivery Point (Rev./Costs)	0	0	0
Wheeling Charges	9,922,383	—	9,922,383
Transmission Losses	0	—	0
Distribution Losses (Rev./Costs)	(9,688,539)	9,688,539	0
Distribution Losses at Supplier Cost	4,646,153	—	4,646,153
Totals	$25,087,555	$24,955,817	$50,043,372

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

Distributor Costs

Year	Distribution Construction Costs	Sub&Trans Construction Costs	Total Construction Costs	Inflated Distribution Costs	Inflated Substation Costs	Inflated Construction Costs	Annual O&M Costs	Annual Fixed Costs	Total Annual Costs	Present Worth of Distributor Annual Costs	Annual Distribution Losses	Present Worth of Inflated Annual Distribution Losses	Number of Delivery Points	Present Worth of Delivery Point Charges
2008	757,388	100,000	857,388	757,388	100,000	857,388	47,185	84,281	131,467	131,467	$469,322	469,322	2	0
2009	757,388	50,000	807,388	783,897	51,750	835,647	96,022	166,425	262,447	247,592	$473,833	473,833	2	0
2010	757,388	50,000	807,388	811,333	53,561	864,894	146,568	251,444	398,012	354,230	$478,344	478,344	2	0
2011	757,388	75,000	832,388	839,730	83,154	922,883	198,883	342,164	541,047	454,274	$482,856	482,856	2	0
2012	757,388	0	757,388	869,120	0	869,120	253,029	427,598	680,628	539,121	$487,367	487,367	2	0
2013	757,388	0	757,388	899,539	0	899,539	309,071	516,023	825,094	616,558	$491,878	491,878	2	0
2014	757,388	0	757,388	931,023	0	931,023	367,073	607,543	974,616	687,066	$496,389	496,389	2	0
2015	757,388	0	757,388	963,609	0	963,609	427,106	702,265	1,129,372	751,097	$500,901	500,901	2	0
2016	757,388	0	757,388	997,335	0	997,335	489,240	800,303	1,289,544	809,076	$505,412	505,412	2	0
2017	757,388	0	757,388	1,032,242	0	1,032,242	553,549	901,773	1,455,322	861,403	$509,923	509,923	2	0
2018	757,388	0	757,388	1,068,371	0	1,068,371	620,108	1,006,794	1,626,902	908,454	$514,434	514,434	2	0
2019	757,388	0	757,388	1,105,764	0	1,105,764	688,998	1,115,490	1,804,488	950,582	$518,946	518,946	2	0
2020	757,388	0	757,388	1,144,465	0	1,144,465	760,298	1,227,991	1,988,289	988,119	$523,457	523,457	2	0
2021	757,388	50,000	807,388	1,184,522	78,198	1,262,719	834,093	1,352,117	2,186,210	1,024,981	$527,968	527,968	2	0
2022	757,388	0	757,388	1,225,980	0	1,225,980	910,472	1,472,630	2,383,102	1,054,048	$532,479	532,479	2	0
2023	757,388	50,000	807,388	1,268,889	83,767	1,352,657	989,524	1,605,596	2,595,120	1,082,853	$536,991	536,991	2	0
2024	1,463,393	0	1,463,393	2,537,503	0	2,537,503	1,147,610	1,855,033	3,002,643	1,181,979	$541,502	541,502	2	0
2025	1,463,393	0	1,463,393	2,626,316	0	2,626,316	1,311,230	2,113,200	3,424,430	1,271,711	$546,013	546,013	2	0
2026	1,463,393	0	1,463,393	2,718,237	0	2,718,237	1,480,576	2,380,403	3,860,978	1,352,670	$550,524	550,524	2	0
Totals	16,508,387	375,000	16,883,387	23,765,262	450,430	24,215,692	11,630,636	18,929,075	30,559,711	15,267,278	9,688,539	9,688,539		0

Supplier Costs

Year	Transmission Construction Costs	Substation Construction Costs	Total Construction Costs	Inflated Transmission Costs	Inflated Substation Costs	Inflated Construction Costs	Annual O&M Costs	Annual Fixed Costs	Total Annual Costs	Present Worth of Supplier Annual Cost	Annual Transmission Losses	Present Worth of Inflated Annual Transmission Losses	Inflated Distribution Losses at Supplier Cost	Present Worth Inflated Distribution Losses at Supplier Cost
2008	2,973,138	4,800,000	7,773,138	2,973,138	4,800,000	7,773,138	0	816,179	816,179	816,179	0	0	292,900	292,900
2009	0	3,100,000	3,100,000	0	3,208,500	3,208,500	0	1,153,072	1,153,072	1,087,804	0	0	304,233	287,012
2010	0	1,475,000	1,475,000	0	1,580,057	1,580,057	0	1,318,978	1,318,978	1,173,886	0	0	315,974	281,216
2011	2,057,500	1,475,000	3,532,500	2,281,187	1,635,359	3,916,546	0	1,730,215	1,730,215	1,452,722	0	0	328,140	275,513
2012	0	0	0	0	0	0	0	1,730,215	1,730,215	1,370,493	0	0	340,745	269,902
2013	0	0	0	0	0	0	0	1,730,215	1,730,215	1,292,918	0	0	353,803	264,382
2014	0	480,711	480,711	0	590,917	590,917	0	1,792,262	1,792,262	1,263,474	0	0	367,331	258,954
2015	0	0	0	0	0	0	0	1,792,262	1,792,262	1,191,956	0	0	381,345	253,616
2016	0	0	0	0	0	0	0	1,792,262	1,792,262	1,124,487	0	0	395,861	248,368
2017	0	0	0	0	0	0	0	1,792,262	1,792,262	1,060,837	0	0	410,897	243,209
2018	0	0	0	0	0	0	0	1,792,262	1,792,262	1,000,789	0	0	426,470	238,139
2019	0	0	0	0	0	0	0	1,792,262	1,792,262	944,141	0	0	442,600	233,156
2020	0	0	0	0	0	0	0	1,792,262	1,792,262	890,699	0	0	459,305	228,261
2021	250,000	1,475,000	1,725,000	390,989	2,306,835	2,697,824	0	2,075,533	2,075,533	973,091	0	0	476,606	223,451
2022	0	0	0	0	0	0	0	2,075,533	2,075,533	918,010	0	0	494,522	218,727
2023	250,000	1,475,000	1,725,000	418,837	2,471,140	2,889,977	0	2,378,981	2,378,981	992,665	0	0	513,074	214,088
2024	0	0	0	0	0	0	0	2,378,981	2,378,981	936,477	0	0	532,285	209,532
2025	0	0	0	0	0	0	0	2,378,981	2,378,981	883,469	0	0	552,177	205,059
2026	0	0	0	0	0	0	0	2,378,981	2,378,981	833,461	0	0	572,774	200,668
Totals	5,530,638	14,280,711	19,811,349	6,064,151	16,592,807	22,656,958	0	34,691,695	34,691,695	20,207,558	0	0	7,961,042	4,646,153

ABC CONSULTANT—ECONOMIC COMPARISON PROGRAM

Client Name: ABC ELECTRIC COOPERATIVE
Plan Number: PLAN D1

One-Ownership Costs

Year	Total Annual Costs	Present Worth of Total Annual Costs
2008	947,646	947,646
2009	1,415,519	1,335,396
2010	1,716,990	1,528,115
2011	2,271,262	1,906,996
2012	2,410,843	1,909,614
2013	2,555,309	1,909,476
2014	2,766,878	1,950,540
2015	2,921,633	1,943,053
2016	3,081,805	1,933,563
2017	3,247,583	1,922,240
2018	3,419,164	1,909,243
2019	3,596,749	1,894,723
2020	3,780,550	1,878,818
2021	4,261,743	1,998,071
2022	4,458,635	1,972,059
2023	4,974,101	2,075,518
2024	5,381,624	2,118,456
2025	5,803,410	2,155,180
2026	6,239,959	2,186,131
Total	65,251,405	35,474,836

EXHIBIT H
SAMPLE SENSITIVITY ANALYSES

ABC ELECTRIC COOPERATIVE
City, State
2008 LONG-RANGE PLAN
One-Ownership Present Worth Sensitivity Analysis*

% Inflation Rate	Plan D	Plan D1	Plan D1A
1.0%	$47,431,239	$47,149,289	$47,547,814
1.5%	$47,907,257	$47,683,278	$48,110,847
2.0%	$48,401,963	$48,238,569	$48,695,471
2.5%	$48,916,286	$48,816,245	$49,302,769
3.0%	$49,451,214	$49,417,445	$49,933,880
3.5%	$50,007,779	$50,043,372	$50,590,010
4.0%	$50,587,073	$50,695,289	$51,272,423
4.5%	$51,190,240	$51,374,529	$51,982,454
5.0%	$51,818,489	$52,082,495	$52,721,508

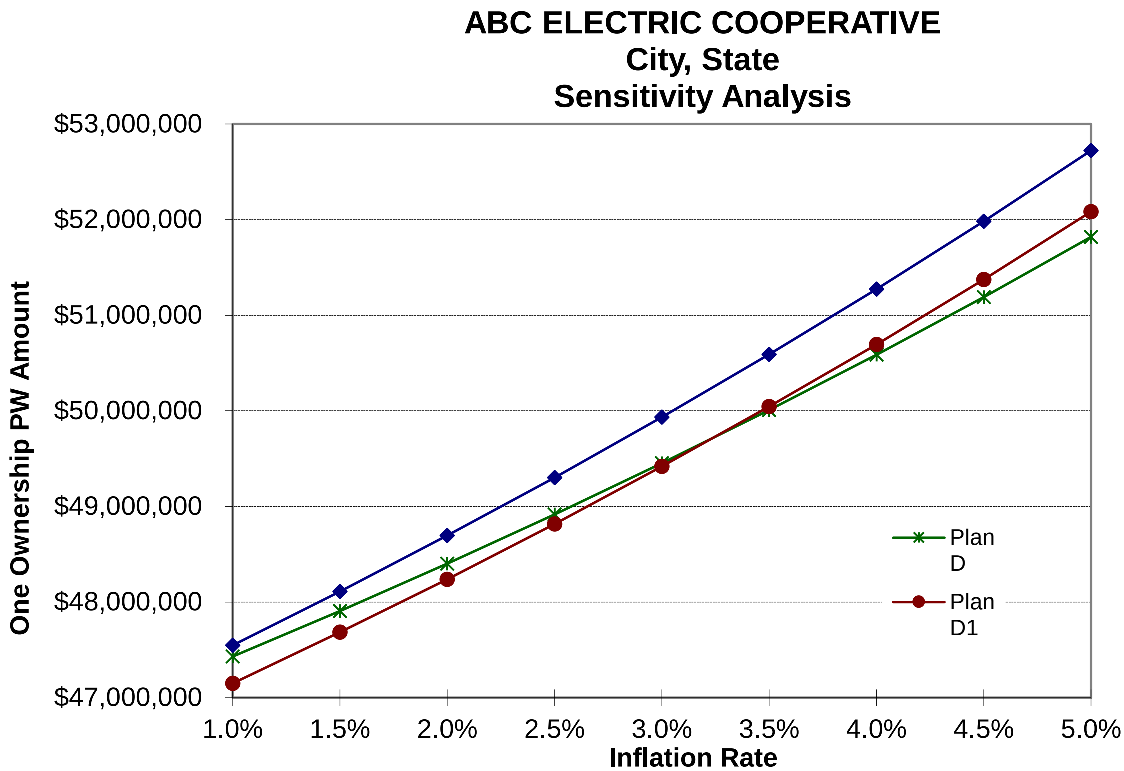
% Load Growth	Plan D	Plan D1	Plan D1A
2.71%	$56,200,499	$56,038,290	$56,526,398
3.40%	$50,007,779	$50,043,372	$50,590,010
4.56%	$41,131,306	$41,422,929	$42,091,843

Energy Inflation Rate	Plan D	Plan D1	Plan D1A
1.0%	$49,349,487	$49,398,720	$49,945,358
2.0%	$49,683,345	$49,725,701	$50,272,339
3.0%	$50,054,417	$50,089,032	$50,635,670
4.0%	$50,467,206	$50,493,103	$51,039,741
5.0%	$50,926,763	$50,942,841	$51,489,479
6.0%	$51,438,753	$51,443,768	$51,990,406
7.0%	$52,009,526	$52,002,075	$52,548,713

Present Worth Rate	Plan D	Plan D1	Plan D1A
4.0%	$59,834,287	$59,930,497	$60,592,357
5.0%	$54,605,925	$54,668,875	$55,269,305
6.0%	$50,007,779	$50,043,372	$50,590,010
7.0%	$45,952,166	$45,965,294	$46,464,672
8.0%	$42,364,821	$42,359,541	$42,817,259
9.0%	$39,182,695	$39,162,372	$39,583,243

Wheeling Cost	Plan D	Plan D1	Plan D1A
$2.00	$49,449,552	$49,616,093	$50,229,369
$2.50	$52,221,503	$51,989,868	$52,232,932
$3.00	$54,993,453	$54,363,644	$54,236,495
$3.50	$57,765,404	$56,737,420	$56,240,057
$4.00	$60,537,355	$59,111,196	$58,243,620
$4.50	$63,309,305	$61,484,972	$60,247,183
$5.00	$66,081,256	$63,858,748	$62,250,746
$5.50	$68,853,207	$66,232,524	$64,254,309
$6.00	$71,625,158	$68,606,300	$66,257,871

** For the three closest plans with different design approaches.*


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
$53,000,000
$52,000,000
$51,000,000
$50,000,000
$49,000,000
$48,000,000
$47,000,000
One Ownership PW Amount
1.0%
1.5%
2.0%
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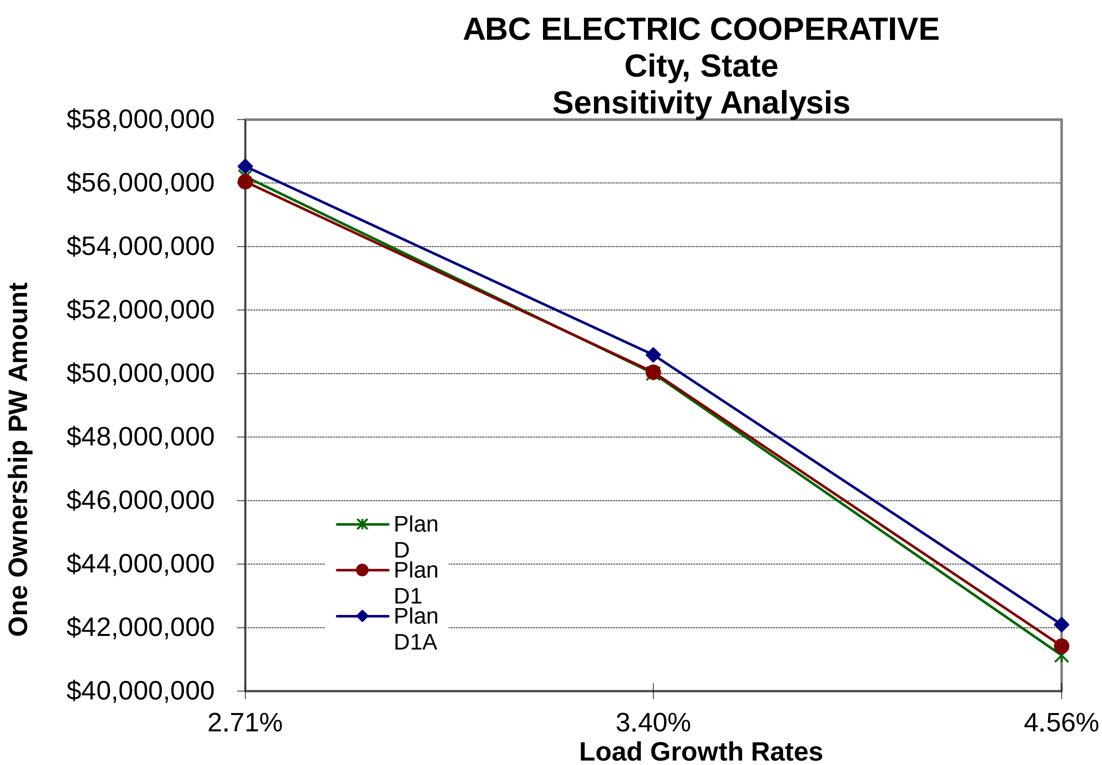
3.0%
3.5%
4.0%
4.5%
5.0%
Inflation Rate
Plan D
Plan D1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City, State
Sensitivity Analysis
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$54,000,000
$52,000,000
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$48,000,000
$46,000,000
$44,000,000
$42,000,000
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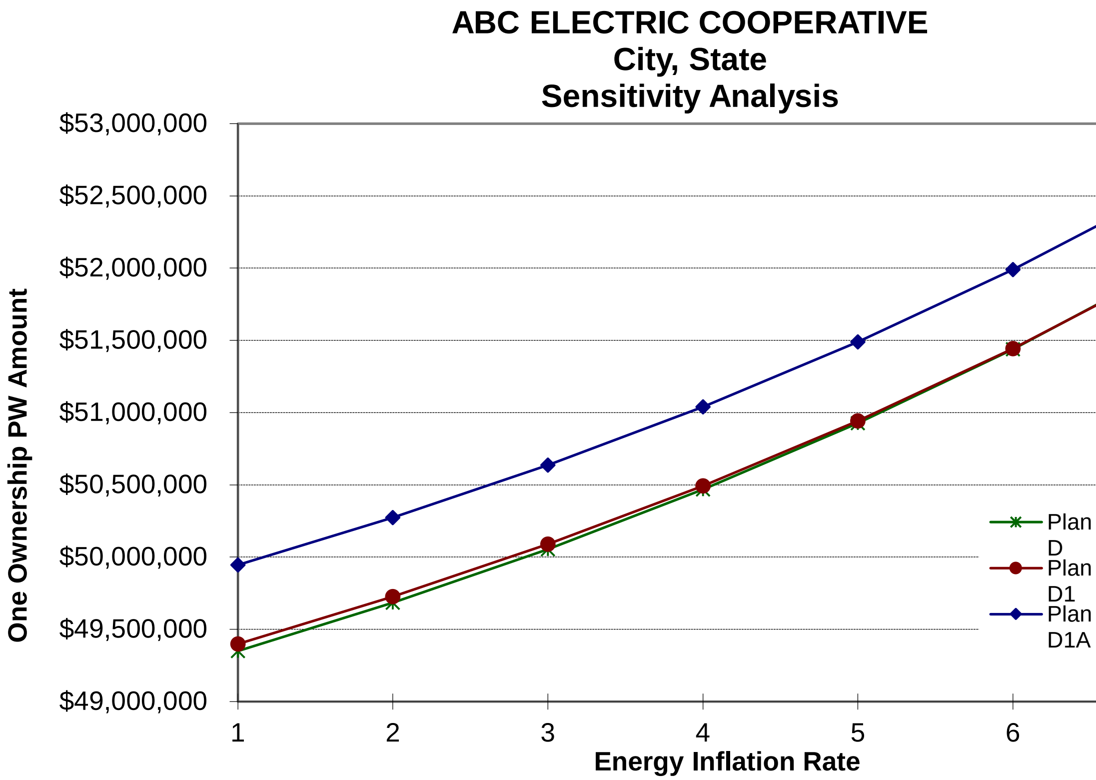
One Ownership PW Amount
2.71%
3.40%
4.56%
Load Growth Rates
Plan D
Plan D1
Plan D1A


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
One Ownership PW Amount
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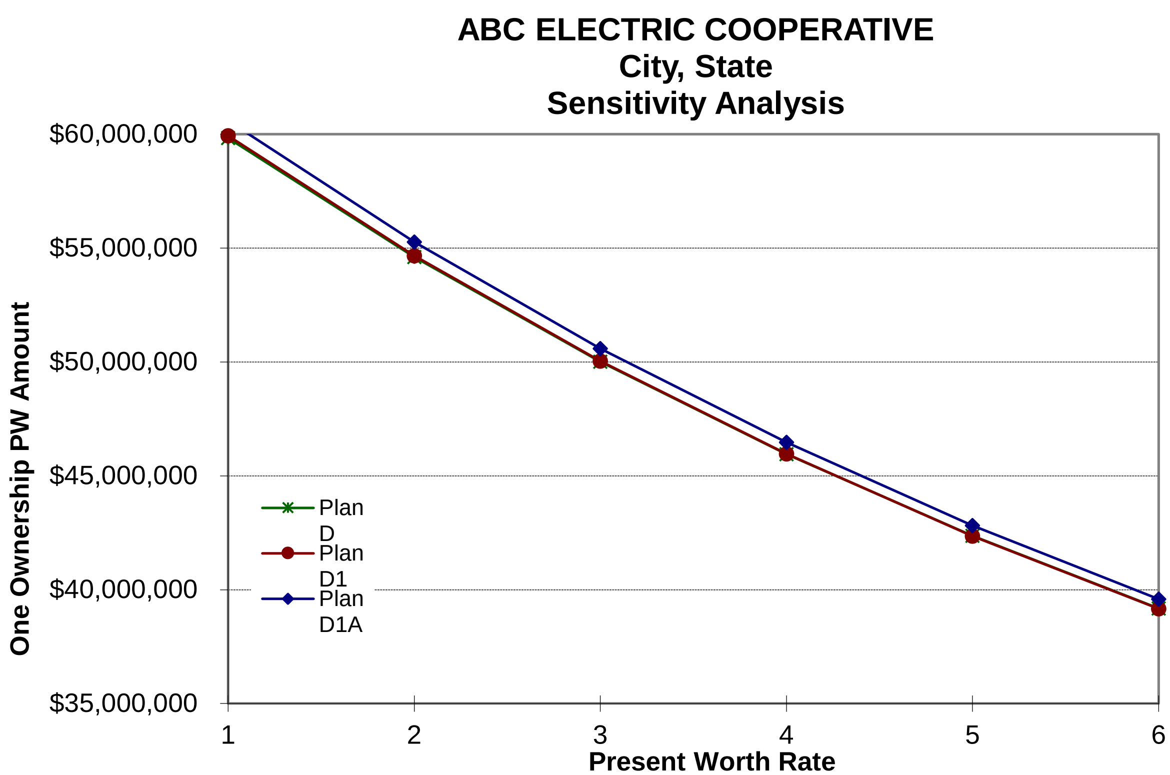
$52,500,000
$52,000,000
$51,500,000
$51,000,000
$50,500,000
$50,000,000
$49,500,000
$49,000,000
1
2
3
4
5
6
7
Energy Inflation Rate
Plan D
Plan D1
Plan D1A


ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
One Ownership PW Amount
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$55,000,000
$50,000,000
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$40,000,000
$35,000,000
1
2
3
4
5
6
Present Worth Rate
Plan D
Plan D1
Plan D1A

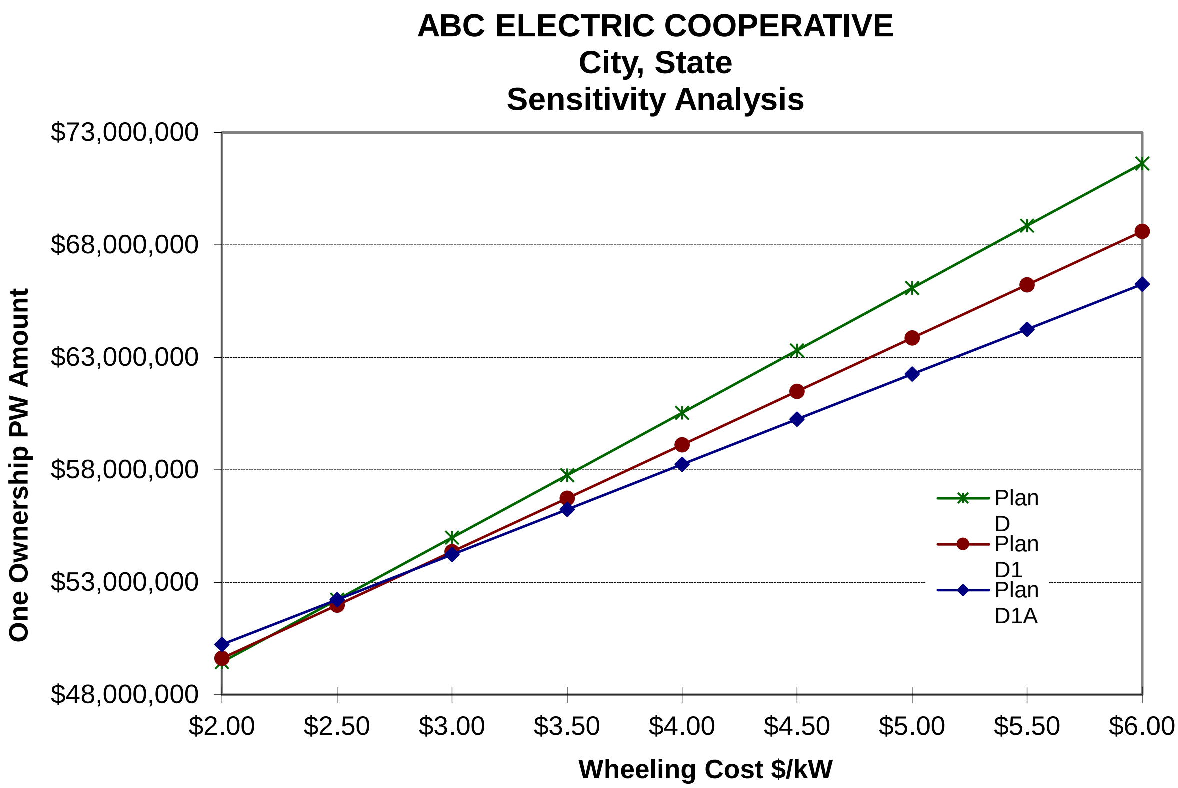
ABC ELECTRIC COOPERATIVE
City, State
Sensitivity Analysis
One Ownership PW Amount
$73,000,000
$68,000,000
$63,000,000
$58,000,000
$53,000,000
$48,000,000
$2.00
$2.50
$3.00
$3.50
$4.00
$4.50
$5.00
$5.50
$6.00
Wheeling Cost $/kW
Plan D
Plan D1
Plan D1A

EXHIBIT I
SUGGESTED TABLE OF CONTENTS FOR LONG-RANGE ENGINEERING PLAN

ABC ELECTRIC COOPERATIVE
2008 LONG-RANGE PLAN
TABLE OF CONTENTS

MAPS*

**Maps for Preferred Plan D1 only. Alternate plans are available upon request. See supporting data for primary analyses of system conditions.*

SUPPORTING DATA

Other appropriate information and data that substantiate the conclusions made in this report have been bound under separate cover and are available from Patterson & Dewar Engineers and ABC Electric Cooperative upon request.

EXHIBIT J
SUGGESTED TABLE OF CONTENTS OF SUPPORTING DATA

ABC ELECTRIC COOPERATIVE
2008 LONG-RANGE PLAN

SUPPORTING DATA
TABLE OF CONTENTS

PLAN D1 (Preferred Plan) **

** *See main long-range study report for further details of the Preferred Plan results.*

EXHIBIT K
CHECKLIST OF LONG-RANGE PLANNING REPORT (RUS FORM 260)

U. S. DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE **CHECK OF SYSTEM PLANNING REPORT** Reference Bulletin 1724D-101A	BORROWER DESIGNATION XX-XXX-XXXXXXX	
	DATE REPORT COMPLETED	NAME OF PLANNING ENGINEER

CHECK		**PART I - THE SYSTEM PLANNING REPORT** *(If "No" column is checked, explain under "Remarks")*
YES	NO	
		1. Does the report present an analysis of the existing system and basic data?
		2. Does the report present a transition from the existing system to the long-range system?
		3. Does the report contain a summary of the exploratory plans which the engineer considered?
		4. Did the borrower have a service reliability standard for the engineer to use as a means of evaluating continuity and reliability of service to consumers?
		5. Was each exploratory plan developed in sufficient detail to clearly establish the basis for selection of the recommended plan?
		6. Have all reasonable exploratory plans been considered?
		7. Have the transitional steps been formed by grouping together various system improvements requiring approximately the same load level?
		8. Are graphs presented relating estimated total plant investment to load levels?
		9. Is a table presented listing the fixed cost elements and the associated percentage of plant investment used for the economic comparisons?
		10. Are economic comparisons of exploratory plans presented on an annual cost basis?
		11. Are summaries of cost data tabulated and identified as called for in Bulletin 1724D-101A (6.5.4)?
		12. Does the report contain a circuit diagram of the complete system for each major step in the transition and for the long-range system as called for in Bulletin 1724D-101A(6.5.6)?
		13. Are the system's transmission lines, if any, and those of the power supplier or other utilities in or near the system's service area shown on the circuit diagrams or other diagrams?
		14. Is the report, including the analysis of the existing system, concise and well-organized so that management can easily work with the report without further engineering interpretation?
		15. Has a copy of a resolution signifying the board of directors' action concerning acceptance of the report been received?

DATE	SIGNATURE

CHECK		PART II—DEVELOPMENT OF THE LONG-RANGE PLAN
YES	NO	
		1. Does the analysis of the existing system give a good understanding of the system's performance?
		2. Is the load level for the long-range system within the range of three to six times the average kwh/consumer/month for the highest peak month experienced to date?
		3. Does each exploratory plan presented, including the long-range plan, make use of existing facilities as long as it is economical to do so?
		4. Does each exploratory plan presented, including the long-range plan, provide a system which is designed to meet the required voltage standards?
		5. Does the transition from the existing system to the long-range system demonstrate a practical and economical development of the system?
		6. Are proposed voltage regulator installations in the long-range plan in accordance with the recommendations in RUS Bulletin 1724D-101A?
		7. Are the cost estimates used by the engineer reasonable?
		8. Are the design criteria established by management reasonable so that they do not rule out logical exploratory plans?
		9. In addition to the economic comparisons, are sufficient comparisons and considerations made to show the superiority of the selected long-range plan over the other exploratory plans?
		10. If indeterminate factors or uncertain conditions exist, is an alternate transition from the existing system to the long-range system proposed?
		11. Is the proposed long-range plan based on power sources that the engineer and the system's management are reasonably sure will be available?

REMARKS

DATE	COMPLETED BY — SIGNATURE

EXHIBIT L
SUMMARY OF LONG-RANGE PLANNING REPORT (RUS FORM 261)

SUMMARY OF SYSTEM PLANNING REPORT	SYSTEM DESIGNATION	DATE PLANNING REPORT COMPLETED
	PLANNING ENGINEER	

PART I—GENERAL DATA

ITEMS 1.	2. LINE MILES TRANS. a.	2. LINE MILES DISTR. b.	3. NO. OF CONSUMERS ALL TYPES *(Including special loads)* c.	3. NO. OF CONSUMERS SPECIAL LOADS d.	TOTAL SYSTEM LOADS *(kW)* 4.	TOTAL SPECIAL LOADS *(kW)* 5.	TOTAL YEARLY SALES *(kWh)* 6.	7. PAST PEAK LOAD kWh/CONS. /MO. a.	7. PAST PEAK LOAD DATE b.	DESIGN LOAD kWh/CONS. /MO. PEAK MO. 8.
PRESENT SYSTEM AS OF________										
LONG-RANGE PLAN										

PART II—LINE MILES

ITEMS 1.	2. DISTRIBUTION 12.5/7.2 kV a.	2. DISTRIBUTION 24.9/14.4 kV b.	2. DISTRIBUTION _______ kV c.	2. DISTRIBUTION _______ kV d.	3. TRANSMISSION _______ kV a.	3. TRANSMISSION _______ kV b.	3. TRANSMISSION _______ kV c.	3. TRANSMISSION _______ kV d.
PRESENT SYSTEM AS OF ___________								
LONG-RANGE PLAN								

PART III—SUBSTATIONS AND METERING POINTS

NAME OR LOCATION* 1.	POWER SUPPLIER 2.	3. PRESENT SYSTEM MVA a.	3. PRESENT SYSTEM kV PRIMARY b.	3. PRESENT SYSTEM kV SECONDARY c.	4. LONG-RANGE PLAN MVA a.	4. LONG-RANGE PLAN kV PRIMARY b.	4. LONG-RANGE PLAN kV SECONDARY c.

PART IV—INVESTMENT IN PLANT *(Thousands of Dollars)*

ITEMS 1.	TRANSMISSION LINES 2.	ALL SUBSTATIONS 3.	DISTR. TRANSFORMERS METERS & SERVICES 4.	ALL OTHER DISTR. FACILITIES 5.	TOTAL T&D PLANT 6.	GENERAL & PROD. PLANT 7.
PRESENT SYSTEM AS OF ____________					$0	
LONG-RANGE PLAN					$0	

** Include those furnished by Power Supplier and designate with asterisk.*

REMARKS:

INSTRUCTIONS

A copy of this form is needed for each system planning report. *(See RUS Bulletin 1724-101A).*

Part I List data as indicated by column headings.
Column 7 *(present system)* actual experienced peak.
Column 8 *(present system)*. Engineer's best judgment as to system's capability in terms kWh/mo/cons. as determined from his "Analysis of Present System and Basic Data."

Part II List the mileage breakdown of all distribution and transmission lines in the present system and similar data for the long-range plan.

Part III List data for each substation or metering point as indicated in the column headings.

Part IV List investment in plant *(dollars)* as indicated by the column headings for the present system and for 2 - 3 - 4 - 5 - 6 for the long-range plan. Investment *(dollars)* for the several columns are included under the following accounts:

Column 2—350 + 351 + 352 + 354 + 355 + 356 + 357 + 358 + 359
Column 3—353 + 362
Column 4—368 + 369 + 370
Column 5—360 + 361 + 364 + 365 + 366 + 367 + 371 + 372 + 373
Column 7—Sum of 389 thru 398 + Sum of 310 thru 345 as applicable.

APPENDIX 1
ECONOMIC CONDUCTOR LIFE CYCLE ANALYSIS

1 BACKGROUND

An Economic Conductor Life Cycle Cost Analysis is a long-term comparison of the costs of alternatives available in the construction of distribution lines. As is the case with many economic decisions, more initial investment will result in more savings in the long term. The goal of this analysis is to identify the best possible combination of initial investment and long-term losses reduction. The end product of Economic Conductor Life Cycle Analysis is, typically, a graph generated by a spreadsheet showing the Total Life Cycle Cost as the Y axis and the Initial Loading as the X axis. See Exhibit E of this *Guide* for an example of such a graph. The graph demonstrates that there are crossover points where it is more economical to choose a larger conductor for higher initial loading.

2 COSTS AND ECONOMIC BREAKDOWN

There are many costs incurred due to the construction and operation of a distribution line. The goal is to identify the *relevant* costs that should be compared for an accurate evaluation. For example, it is obvious that, for a higher-cost line, there will be more annual taxes because taxes are based on value. However, does a larger or smaller wire size really result in a measurable difference in annual operation and maintenance expense? One of the largest maintenance expenses, right-of-way trimming, would be the same for a smaller wire size as it would be for a larger wire size. It is up to the cooperative planning engineer to identify and quantify real annual differences for the purposes of this evaluation.

Estimated plant life should be based on the best historical information available. In some climates, conductor may last more than 30 years. Where growth is a major concern, it is possible that—due to reasons such as road widening—conductors may not be expected to be in service for more than 20 years. The various components of the analysis will have an impact on the outcome and should be reviewed thoroughly.

The value of losses is sometimes a difficult number to derive. It is important to remember that you are considering the *future* value of losses and that historical demand and energy charges are usually blended costs of embedded investments. What you are considering is the reduction of losses that otherwise would have to be generated from tomorrow's generation plants at much higher rates than embedded, historical costs. This will result in the increased value of losses and a trend toward larger conductors.

The key to conducting a successful comparison of life cycle costs is to begin with accurate base data. The most important figure is the construction costs of a mile of line for a wire size. Very detailed reviews must be conducted to determine the best cost. Outliers—conductors evaluated with very high or low costs—that are on the extreme ends should be reviewed in detail and possibly removed from the cost development. Estimates of construction costs for wire sizes with no history should be carefully estimated. Some determination of additional costs due to larger wire, shorter spans, increased pole class, possibly heavier hardware, etc., must be made. Conversations with neighboring cooperatives that are using different size conductors would aid in the estimation process.

An important item to consider in the evaluation process is that there are two components to selecting feeder conductors. Initially, conductor selection is accomplished at a high level to pick the few major wire sizes and types to be used for the next 10 to 20 years. Once that macro analysis is done, a comparison on a more micro level is possible. It is important, after the long-range plan (LRP) is completed, that appropriate segments of line are analyzed prior to design and construction. For example, a very long feeder is probably not uniformly loaded for its entire length. If the feeder splits after the first mile or so into several significantly loaded directions, the first segment should be considered separately from the remainder of the feeder or other significant, identifiable segments. Due to the ease of use of modern Economic Conductor Life Cycle Cost Analysis spreadsheets, this would be a very prudent exercise.

There are a number of Economic Conductor Life Cycle Cost Analysis spreadsheets or programs available. Generally, the differences lie in respect to the level of detail they offer. For the purposes of this *Guide*, a standard Economic Conductor Life Cycle Cost Analysis spreadsheet will be reviewed.

3 VARIOUS CONDUCTOR TYPES

A brief review of common aluminum conductor options is presented below. When accomplishing an LRP and a conductor alternative study, a more detailed consideration of the available types of conductor should be considered. There are distinct advantages and disadvantages to using certain conductor types and sizes under different local conditions. For some areas of the country, conductors with high tensile strength or reduced vibration are more advantageous because of longer spans or terrain. Some situations may require conductors with increased conductivity and thermal ratings. Some areas may require higher corrosion resistance. These localized and specific requirements must be considered and weighed during the selection process.

Key conductor types being manufactured today are:

<u>All-Aluminum Conductor (AAC)</u>. AAC conductor is a high conductivity cable that consists of aluminum wires concentrically stranded. Generally this conductor is preferred in heavily loaded urban areas where short spans and high current levels exist. The aluminum used is a compound known as 1350-H19, which has a good combination of conductivity and corrosion resistance.

<u>Aluminum Conductor, Steel Reinforced (ACSR)</u>. ACSR has been the standard for overhead distribution and transmission conductor for years. It has a good combination of strength and ampacity. The conductor consists of a steel core surrounded by layers of

aluminum (1350-H19). Higher strength is achieved by increasing the number of steel support core wires for use in transmission systems or particular distribution applications of extremely long spans. An advantage that ACSR has over AAC is that the steel core decreases the sag of the conductor and allows a higher thermal rating to be achieved for a particular span length. The steel also increases the strength of the line providing greater resistance to ice and breaking problems.

All-Aluminum Alloy Conductor (AAAC). AAAC was designed to compare favorably to ACSR in strength to weight and in ampacity. The wires within the conductor are an aluminum alloy (6201-T81) developed to be stronger than the 1350-H19. The biggest advantage that AAAC has over ACSR is that it is much more corrosion-resistant and abrasion-resistant. Because of this, it is particularly beneficial along coasts or corrosion-prone areas.

Aluminum Conductor, Aluminum-Alloy Reinforced (ACAR). ACAR is a conductor that consists of separate strands of the aluminum alloy (6201-T81) found in AAAC along with 1350-H19 aluminum strands. There are a number of different configurations for the same wire size to optimize ampacity or strength for a given application.

Specialized Conductors. There are a number of other special configurations and materials available to address specific problems, such as vibration, increased tensions, or other concerns. These are typically very specialized products and outside the scope of this manual. However, it is worthwhile to research and evaluate these conductors to address certain needs.

4 CONCLUSION

Selecting and standardizing on a selected few conductor types is a key responsibility of the distribution planning engineer. Typically, two or three types of conductors are chosen: one for lightly loaded single-phase and three-phase lines, one for medium-loaded three-phase lines, and one for heavily loaded and main substation tie lines. The key factor in making the decision is economics. However, the operational control function of conductor availability is also another key factor. Each conductor evaluated for economics must be evaluated for availability. Each electric system experiences environmental conditions and land attributes that have to be considered for rebuilding and conductor availability. These conditions vary but can be summarized as follows:

- Coastal atmospheres with high corrosive attributes,
- Ice storms,
- Tornadoes,
- Hurricanes,
- Earthquakes,
- Flooding, or
- Mountainous terrains.

The above list is in no way complete and inclusive, but does highlight the factors the electric planning engineer needs to consider when selecting conductors for line construction.

APPENDIX 2
RADIAL TRANSMISSION LINE RELIABILITY AND OPERATIONAL ASSESSMENT

1 BACKGROUND

A radial transmission line serving distribution substations is defined as distribution delivery point(s) served by a transmission line system that does not have any other means of transmission service. If there is a failure of the transmission line, there is a resulting power outage to the substation (or substations) until the line is repaired. A service reliability study will indicate areas of the system which need special attention and may even indicate the general type of work which will be most cost-effective in correcting such service deficiencies. If the transmission supplier is responsible for an excessive amount of the outage time (typically, more than one consumer-hour per consumer/year averaged or trended over five years), this should be noted. The transmission supplier should be requested to provide comparable outage analyses for all similar delivery points.

Reliability should be based on standards or criteria established by the cooperative or other national organizations. A service reliability standard provides a basis on which management can evaluate system performance. Please see RUS Bulletin 1730A-119 entitled "Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems" for further details regarding RUS service reliability polices. Also, the system planner should be fully aware of the transmission line reliability policies and indices as required by the Federal Energy Regulatory Commission (FERC) as administered by the North American Energy Reliability Council (NERC). Most FERC/NERC guidelines deal with the bulk transmission grid; however, they do have an impact on the reporting that each power supplier is required to file.

The importance of service reliability should be reflected in the long-range system plan. Because of wide differences in operating conditions and local requirements, RUS does not attempt to specify a service reliability standard for all systems. However, each borrower should adopt a standard, which will serve as a goal in the development of its system. The five consumer-hours per consumer per year interruption rate used for loan applications should not be considered as a goal. Rather, system goals should be nearer one hour for suburban and two hours for rural consumers. Furthermore, it should be recognized that, except during truly unusual major storms, consumers are not concerned with the source of an interruption. Whether the power is off only for their individual transformer or because of a power supplier's interruption makes little difference to the consumer. Thus, all sources of interruption should be considered for possible improvement in service reliability.

The need for improvements to radial transmission lines can be separated into two different categories: performance and exposure. Addressing a radial transmission line's performance can involve significantly different factors than addressing a similar line's exposure. For example, improving ROW or adding lightning arrestors are good approaches to improving performance; however, they do nothing to reduce exposure. By the same token, providing an alternate transmission source may improve SAIDI metrics but momentary outages and frequency of outages will remain unchanged unless the alternate transmission source becomes the primary source.

Whether the transmission lines are owned by the distribution system or the transmission supplier, planning should be approached on a “one system” concept. Excessive costs for transmission facilities cannot be justified by minor savings on one part of the system. The converse is also true that excessive distribution plant should not be constructed simply to avoid transmission construction. The economy of radial-feed substations should be weighed against the reliability of loop-feed substations. The applicability of each design, as it pertains to the basic system design and established operating practices, should be carefully considered.

To aid in such an assessment, the following procedures and the attached form have been created. With the planning engineer and all associated parties working together to complete the factual data required, all pertinent conditions can then be assessed. By answering the questions listed with a clear yes or no, needs can be established and all parties can agree that long-range plans should attempt to satisfy those needs. If many of the questions are answered in the affirmative, clear reliability concerns are present and system improvement options should be reviewed under the “one-ownership” concept to identify the economics for improved reliability of each option.

2 PROCEDURE

The general process for accomplishing the assessment is as follows:

1. The transmission line provider and cooperative/distributor are to review the current radial electric power delivery system and identify any weak links that involve significant load requirements. (Note: The transmission and substation provider and cooperative/distributor may be the same entity). A weak link is identified as a system configuration that has recently contributed to an extensive unplanned outage and/or a condition that would require a lengthy outage in order to accomplish extensive maintenance. Radial transmission lines without backup or looping options are prime components that need to be reviewed. It is not the intent of this assessment to review and evaluate every radial transmission line in the cooperative/distributor’s service area, only those lines that have recently presented a problem or have significant current or future high load conditions.

2. After identifying the weak links, factual data is to be accumulated by the transmission line provider and cooperative/distributor, and tabulated on the attached form. After tabulating the factual data and answering the questions, the number of affirmative answers can be counted.

3. If there are a number of affirmative answers tabulated, long-range planning should include the review of economical ways to improve and/or eliminate the weak links.

4. After a thorough review of possible solutions using the “One Ownership” method, the cooperative/distributor can decide which options, if any, should be included in its long-range plan. The attached form can be used as a general tool for documenting what is to be included in the new LRP and why. It is *not* to be considered an official commitment document for system improvements. It is only a tool for communicating with the various electric system owners. It is further understood that agreement to include the weak link in the planning process in no way commits any party to construct the system improvement required to resolve the weak link.

5. After an economic review of the options has identified that the weak link can be eliminated or improved in the long range, all system parties/owners should commit to planning those system improvements. If they cannot, all parties agree to live with the weak link and work around it as conditions dictate.

3 MEANING OF TERMS (Listed in Form Order)

The terms used in the Radial Transmission Line Reliability and Operational Assessment form are defined as follows:

<u>T/L #</u>. The designation given by the long-range system study for the Transmission Line (T/L) under consideration.

<u>Transmission Line Description</u>. A short phrase that defines clearly the T/L under review.

<u>Operating Voltage</u>. The phase-to-phase nominal operation voltage of the line.

<u>Conductor Size and Type</u>. Denotes the wire size and type. Including the “word code” would be very helpful. An example is “336 kcmil ACSR (Linnet).”

<u>Right-of-Way Width</u>. Denotes the available width of ROW in feet.

<u>Radial Distance</u>. The length of the T/L from the bulk feed or looped line to the cooperative/distributor’s delivery point, recorded in miles. If more than one delivery point is associated with the radial line, the line distances between each delivery point are to be determined and recorded.

<u>Peak Load</u>. The maximum non-coincident peak electric load is the highest ever experienced on the system or, at least, over the last 12 months, expressed in megawatts (MW). If there is more than one delivery point associated with the radial line, the peak loads are to be tabulated for each delivery point.

<u>Last Peak Time</u>. The month and year of the last peak load is identified.

<u>Load Distance Service Factor (LDSF)</u>. This is the arithmetical product of the radial T/L distance (in miles) times the last peak load experienced on the line (in MW). The LDSF

is recorded in MW-miles and is a numerical value for the planning engineer to assess the criticalness of electric load to a distance of T/L. The factor really has no real meaning and is to be used only as a guide for assessing the need for system improvements and T/L looping. If there are multiple substations or delivery points served by the T/L, an LDSF is to be calculated for each point, including the total load being served from and through that delivery point.

Transmission Line Provider. The organization that has responsibility for planning, maintaining, and operating the T/L under review.

Cooperative/Distributor or Cooperative. Refers to the organization that distributes power from the delivery point that is served by the radial T/L.

Significance of MW-Miles. Planning engineers in the T/L and distribution business have generally agreed that, when radial transmission line loading reaches an LDSF greater than 100 to 150 MW-miles, efforts should be included in system long-range planning to look for ways to reduce the radial exposure. This should be considered only a guide and not a mandate in system long-range planning.

Poorly Accessible T/Ls. Refers to T/Ls that have rights-of-way (ROW) that, for whatever reason, are not readily accessible during a significant part of a given year. Reasons for inaccessibility could be, but are not limited to, the following: ROWs that are very swampy and subject to rainy seasons; ROWs that are mountainous and subject to snow or icy conditions during parts of the year; and ROWs over waterways with T/Ls built off pilings or piers.

High-Priority Loads. Distribution loads served by the cooperative/distributor that would experience severe uneconomical or life-and-death conditions if an extensive outage occurred. Typical loads that would experience such could be hospitals, industrial/manufacturing plants, airports, commercial loads, large oil and gas pumping loads, etc. Service areas where consumers rely heavily on electricity for heating could, likewise, be considered a high-priority load.

Conductor Condition. Occasionally, T/L providers perform sample testing on very old (i.e., more than 30 years) conductors to see if their condition is suitable for further long-term use. If conductors are found to be in reasonably good condition (e.g., they are not brittle or prone to breaking, the steel core is not rusty or missing, etc.), then they can continue in use. If, however, such is not the case, replacement or repair of the Radial Transmission Line (RTL) needs to be included in the long-range planning process.

Three Outages Over Last Two Years. T/Ls that have experienced more than one outage per year over the last two years due to poor line hardware indicates poor and depreciated equipment conditions and are in need of replacement and/or improvement that should be included in long-range planning.

Four-Hour Outage Within 12 Months. A four-hour outage can be critical for many distribution loads and must be considered when long-range planning takes place. T/Ls having such operational conditions with a high LDSF should be reviewed in the system long-range planning process.

Unreliable Line Percentage. FERC requires that T/L providers identify the reliability of all their lines and rate them in order from least to most reliable. With such information, the power supplier or transmission line provider can quickly tell if the radial T/L under review is within the top 5% of most unreliable lines on their system. If it is, it is important that system improvements be reviewed in long-range planning.

Loaded >50% Capacity. Radial T/Ls projected to be peak loaded over 50% of published full load capacity should be evaluated for long-range system improvements, especially for lines operating at ≤ 69 kV. Published capacity denotes the manufacturer's rating, typically with conductor at 75ºC, ambient temperature at 25ºC, emissivity at 0.5%, wind at 2 feet per second, and the conductor in direct sunlight.

Operating Voltage ≤ 69 kV. Radial T/Ls operating at subtransmission voltage levels can have high line losses and voltage drops when heavily loaded and are not good for bulk feed looping. Such voltage levels do not directly impact system reliability but do impact system operations and economics. Also, such voltage lines are weak for transformation to 25 kV distribution. As a result, such lines are a good place for possible system improvements or changes within the surrounding service area.

4 RADIAL TRANSMISSION LINE ASSESSMENT FORM

The form below is for assessing the reliability of radial transmission lines. It can be duplicated for as many radial T/Ls as the power supplier, transmission line provider, and/or cooperative/distributor identify as needing review. Electronic or Excel® versions can be acquired from the NRECA T&D System Planning Chair and the Staff Director of the RUS Electrical Engineering Branch.

Radial Transmission Line Reliability and Operational Assessment

Radial Transmission Line (RTL) Characteristics: RTL #:__________

Name and Description: ____
Operating Voltage (kV): ____________________ Conductor Size & Type: ________________________
Right-of-Way Width (feet):_________________ Radial Distance (miles): ________________________
Last Peak Load (MW):_____________________ Peak Time (month, year): ________________________
Load Distance Service Factor (MW-Miles):[A] _______________________ Year Built: _______________
With loss of the RTL, what % of load can existing distribution ties support? ________________________
Major Line Maintenance Cycle Years: ____________
Year of Last Major Line Maintenance: ____________
Right-of-Way Location (cross-country, roadside, etc.): ____
Right-of-Way Maintenance Cycles (years): ____________
Frequency of Right-of-Way (years):
Inspections ______________ Mowing/Spraying ______________
Danger Tree Removal ______________ Side Trimming ______________
Transmission Line Provider:____
Impacted Distributors or
Cooperatives: ____

RTL Reliability and Operational Questions[B]	No	Yes
1. *Does the RTL have a high Load Distance Service Factor (LDSF) greater than 150 megawatt-miles?*	___	___
2. *Is the RTL poorly accessible as determined by the Owner during all or part of the year?*	___	___
3. Does the RTL serve a delivery point that provides power to high priority loads (e.g., hospitals, manufacturing parks, airports, commercial loads, etc.)?	___	___
4. *Is the conductor in deteriorated condition based on recent sample testing?*	___	___
5. *Is the RTL condition contributed to more than three sustained outages over the last two years?*	___	___
6. *Has there been an outage over four hours in the past five years attributed to the RTL (excluding those during a major storm)?*	___	___
7. *Is the RTL in the power supplier's top 5% of most unreliable lines?*	___	___
8. *Does the RTL owner have any major improvement plans in the near future or in the general area of the distributor/cooperative substation?*	___	___
9. *Is the RTL operating at 69 kV or less and have a >50% of the conductor published full load amperes for the projected long-range peak loading conditions?*	___	___

Number "Yes" Responses[C] = ___

RTL PLANNING COMMITMENT

Based on the above assessment, the electric system distribution engineer has decided that the referenced RTL ________ ***is*** or _______ ***is not*** to be included in the new electric system long-range plan. A copy of this assessment and commitment is to be supplied to the RTL provider indicated above.

Signature: ____
Distributor's Planning Engineer Name: ____
Distributor's Planning Engineer Title: ____

[A] Load Distance Service Factor = (Latest Peak Demand Load Served) × (Radial Line Distance)
[B] Categories shown in italics are to be answered by the RTL Owner and Provider, if applicable.
[C] RTLs that have a number of "affirmative" responses to the reliability and operational questions above should be included in the long-range planning process.

APPENDIX 3
AGING CONSIDERATIONS FOR LONG-RANGE CAPITAL EXPENDITURES

A cooperative needs to balance capital expenditures across all parts of its system to maintain an acceptable level of service for all consumers. This appendix addresses the challenges that arise when all or part of the system is experiencing stagnant growth or declining loads, including the issue of allocating available funds between growth and non-growth areas.

The problems commonly encountered in aging, low-growth distribution systems can be described as follows:

- Deteriorated poles, crossarms, etc. > 35-50 years old
- Deteriorated and obsolete conductors (copper-clad and aluminum) > 40 years old, especially those with excessively long spans and aging conductors
- Deteriorated and obsolete substations (wooden structures)
- Deteriorated and obsolete substation transformers
- Deteriorated transmission lines (34.5 kV, 46 kV)
- Deteriorated reclosers and switches
- Deteriorated voltage regulators and regulator controls
- Excessive electrical losses (primary, secondary, and transformer)
- High levels or unknown levels of PCBs in power and distribution transformers
- Deteriorated concentric neutral underground cable where the neutral is corroded away
- Inadequate or ineffective lightning protection
- Inadequate or ineffective grounding, causing excessive stray voltages
- Inadequate sectionalizing and overcurrent protection
- Deteriorated knife blade switches
- Deteriorated and improperly maintained reclosers
- Deteriorated insulators causing excessive radio noise
- Deteriorated Air Break Switches out of adjustment or inoperable due to corrosion
- Insufficient grounding and insufficient lightning arrestors
- Rusting equipment enclosures (especially pad-mounted equipment)
- Obsolete SCADA system (no spare parts or support)
- Obsolete two-way radios (no parts available)
- Obsolete microwave systems (no spare parts available)

<u>Outage Criteria</u>
Cooperatives are expected to provide improved outage reliability and power quality to their members. Sectionalizing schemes and equipment used 20 or 30 years ago will usually not be acceptable to today’s electric consumer. Reliability suffers even further when the distribution system begins to deteriorate. The cooperative’s management and engineer must determine the reliability requirements that their membership expects and plan accordingly.

<u>System Losses</u>
System losses are a substantial financial drain on any system, and the average cooperative has losses in the hundreds of thousands of dollars every year. The cooperative should track losses by

substation on a monthly and yearly basis in order to identify problems in different parts of the system. While losses are a costly part of system operation, they also present an opportunity. Reducing losses reduces overall costs.

The continued use of small, aging conductors can contribute substantially to losses.

Underground Cable is one of the many troublesome spots on an aging system.

- High Molecular Weight (HMW) cable has proved to be very unreliable and should be replaced as soon as possible
- Bare concentric neutral cables are often found to have neutral conductors that are badly corroded or completely gone, which causes numerous operating problems.
- Non tree-retardant cross-linked polyethylene cables (XLPE) begins to have a high rate of failure as it ages.

The location and quantities of these types of underground cables should be recorded and evaluated for failure rate and plans made for their possible replacement.

Old and Depreciated Transformers

- Does the cooperative have any old 1.5 kVA, 3 kVA, 5 kVA, or possibly any 7.5 kVA transformers still in service? Check the continuing plant records (CPR) or mapping records.
- Are there any PCB transformers or capacitors or substation PCB transformers left? These may need to be replaced after checking the kWh/kW usage, etc.

Rights-of-Way

Right-of-way (ROW) problems can be a significantly costly item as well.

- How many miles of right-of-way that need to be cleared periodically?
- Are the ROWs in worse condition in the slow-growth areas?
- How many miles were cleared, cut, or mowed last year?
- How many years will it take, based upon past performance, to clear ROWs on the entire system?
  - Determine the optimum clearing cycle based on the differing growth rates of vegetation in the area.

Recloser Maintenance

- Are the operations counters on all reclosers regularly recorded?
- Is a formalized maintenance plan in place? Old, poorly maintained reclosers will seriously reduce system reliability.
- Are sectionalizing studies up to date?

Electronic Recloser/Breaker Maintenance

- Electronic recloser controls and breaker relay should be regularly tested.

- Old, obsolete units should be replaced. These controls are usually used in substations and main feeders, and have the largest impact on the proper operation of the system sectionalizing scheme.

Voltage Regulators
- Are operations counters read regularly?
- Has the number of operations exceeded manufacturers' recommendations, typically 20 years or 1,000,000 operations (see manufacturers' recommendations)?
- Can the regulator stand the available fault current if a fault occurs? In general, this is 40 times the nameplate ampere rating of the regulator for a time period of 0.8 seconds.

Pad-Mounted Equipment
Maintenance issues with transformers, switchgear and other pad-mounted equipment can be a big expense to the cooperative.
- Structural problems are the predominant failure mode.
- Rust and corrosion are a major concern.
- Oil leaks can also occur.
- Routine visual inspection is required (see CRN Report #98-11, entitled *Motor Problem Resolution and Avoidance*, for further details).

Aging Conductors
Given the fact that overhead electrical conductors have an average life expectancy of approximately 50 years, it is clear that many original distribution lines are approaching the end of their useful life span. (See CRN Report #00-31, entitled *Guide to When to Replace Distribution Line Conductors*, for additional details.) Conductor replacement should be strongly considered with a pole replacement program, to avoid the wasteful expense of setting new poles in a line with old conductors.

Some of the commonly used original conductors are as follows:

Size	**Type**	**App. Ampere Capacity**	**Rated Breaking Load (lb.) NEW Conductor**	**Weight (lb./mile)**
2A	Copperweld-Copper	240	5,876	1,356
4A	Copperweld-Copper	180	3,398	853
6A	Copperweld-Cooper	140	2,585	536
8A	Copperweld-Copper	100	2,233	392
9-1/2 D	Copperweld-Copper	65	1,743	298
3 #12	Copperweld	90	2,236	289

Some of the more common reasons why conductors fail include:
- Ice loading that exceeds maximum conductor tension;

- Long spans with ice loading, resulting in elastic stretch;
- Arcing damage from trees, lightning, wind, etc.;
- Surface corrosion on copper-clad conductors that leads to steel corrosion;
- Electrolytic corrosion due to galvanic action;
- Surface corrosion and inner corrosion of the steel strand on aluminum conductors;
- Loss of zinc coating on steel core wires (ACSR conductors);
- Fatigue failure due to wind-induced vibration; and
- Annealing due to excessive electrical current (hard-drawn copper wire).

Record Keeping on Conductors

It is very helpful to keep detailed records when conductors fail, including the reason for the failure, , size of conductor, condition of conductor, approximate age, span lengths, etc. A database should be created and maintained detailing conductor failure by substation, by circuit, and by geographic area.

Inspection Provisions

The inspection provisions are contained in the *2012 National Electric Safety Code* (NESC), Section 214. A good inspection program is intended to identify areas or equipment that need maintenance or replacement. Maintenance must be done a regular basis to keep up with the inspection process, otherwise the process breaks down and system reliability suffers. Maintenance and inspection programs should be part of the planning and budget process to insure that adequate funds are available to maintain the programs.

RUS Bulletin 1730-1, *Electric System Operation and Maintenance* (O&M), includes more detailed directions on the inspection process. It is important to keep in mind that line patrol is usually carried out while walking, riding or flying a line to look for obvious right-of-way or pole-line condition problems. Line patrol does not usually involve a detailed pole-by-pole inspection to find loose hardware, cracked insulators, etc. While a detailed line inspection program would be the ideal, it generally proves too slow and costly to allow for regular, economical maintenance and upkeep of the distribution system. However, the use of radio frequency interference (RFI) and/or infra-red detection equipment during line patrol may detect conditions such as loose connectors and cracked insulators that may otherwise be missed.

Voltage Drop

One of the classic problems associated with small conductors used with older lines is excessive voltage drop. All distribution systems should have their engineer regularly perform a distribution voltage drop study (usually done as part of a construction work plan) to insure that parts of the system are not experiencing excessive voltage drop. The results of the voltage drop study will identify overloaded conductors and areas with low voltage that may require reconductoring or the addition of voltage regulators.

Distribution System Model Discrepancies

In order to effectively perform a distribution voltage drop study, the system model must be reasonably accurate. Older low-growth systems often find that errors have crept into their models over the years, such as:

- Line sections are of wrong length.
- Mixed conductor spans are entered into the database as the largest conductor (i.e., 1 #6, 1 #8, 1 #4, with an 8A neutral is listed in the model as 3-phase, 4 CU).
- Regulators and capacitors are missing or listed in wrong locations.

Process for Formulating an Engineering Solution

1. Quantify the problem by making a list of all known system deficiencies in the slow-growth areas.
2. Quantify the number of consumers that would be affected by an outage on a particular section of line.
3. Estimate costs to repair/replace each item based on current costs.
4. Prioritize the list of problem areas based upon one or more of the following subjective criteria using good engineering judgment:
   (a) Cost/benefit ratio
   (b) Outage reduction
   (c) Improved losses
   (d) Reduced liability
   (e) Improved operational flexibility
   (f) Improved safety
   (g) Fewer consumers affected by an outage
5. Examine the current work plan in the following areas:
   (a) Quantify proposed investment in slow-growth areas.
   (b) Review RUS Form 7 (year-end) of completed work orders and determine how much investment in slow-growth areas was added to plant over last year.
   (c) Compare these two numbers to determine the extent of the problem. If the work order amount spent in low-growth areas last year is relatively low compared to the proposed improvements in that area, then the capital budget will have to be substantially increased to pay for the needed improvements.
6. Determine the number of poles and amount of line that needs to be replaced.
   (a) Approximately 20 poles/mile × miles of line = number of poles on the system.
   (b) Review CPR records of poles. How do they compare?
   (c) Estimate the average age of the poles on the system. It is best if the average age can be broken down by substation area.
   (d) How many were inspected and treated with a ground line treatment, if needed?
   (e) How many years will it take to completely inspect the system at last year's inspection rate, and is that time frame acceptable considering the average decay rate in the region. How many poles were replaced last year?
   (f) Determine cost/benefit or payback period on treating poles.
   (g) A plan should be put into place to have poles replaced by the end of a reasonable life expectancy.

(h) Quantify how many miles of copper/copper-clad line are still in service. Check the CPR records, the engineering model, and the system maps. Most copper lines are *at least* 50 years old.

(i) It is good practice to remove all steel lines as soon as practicable.

(j) Is there a current plan to replace copper/copper-clad line? Copper replacement programs should be budgeted and approved in a construction work plan.

(k) It is usually most practical to replace portions of the copper lines each year according to a prioritized list. It is recommended that systems replace all small 1-phase or V-phase copper distribution lines within the next 10 years or less, depending upon their condition and the outage experience on the specific line.

<u>Balancing Capital Needs</u>

1. Examine the current construction work plan to see what percentage of the total dollars in the work plan is budgeted for replacing aging plant (usually classified in the work plan as ordinary replacement).
2. After quantifying the extent of the aging problem, determine the timeframe in which remedies have to be made and, therefore, how much capital needs to be budgeted to ordinary replacement on a yearly basis.
3. Compare new investment dollars per consumer in the various areas of the system or by substation.
4. Depending upon the age and condition of the system, 10 percent to 30 percent of the total annual work plan budget may be earmarked for aging plant problems. Experience has shown that older, low-growth, high-equity systems are often not in very good condition either physically or electrically.
5. An electric utility business requires continuing capital investment supported by carefully managed depreciation and capital addition programs. Judicious use of borrowed funds for physical plant that will last at least 35 years is a prudent financial practice.

<u>Summary</u>

The cooperative should:

1. Develop a detailed list of all known system operation and maintenance problems. All systems are not the same, and the problems will vary according to terrain, climate, and electrical load patterns.
2. Quantify the remedies in dollars, man-hours, capital expenses, etc.
3. Prioritize the remedies based upon the criteria outlined above.
4. Budget funds for the highest priority items.
5. Construct the facilities as planned through construction work plans.
6. Update the aging plant area list, and re-prioritize and re-budget yearly or during work plan cycles.
7. Follow through with the plan, and complete the needed replacement. Failure to address these issues in a timely manner is likely to have grave financial consequences.

APPENDIX 4
DISTRIBUTED GENERATION IN LONG-RANGE PLANNING

1 BACKGROUND

In 1936, when the Rural Electrification Administration was created by the U.S. Congress, Distributed Generation (DG) was not even on the radar screen. In fact, for most rural areas, electricity was only a wish and a hope for the future. Of approximately 6.3 million farms at that time, only about 205,000 were receiving centralized electric service. By the early 1970s, about 98% of all farms in the United States had electric service—quite a success story for the REA program. Where there is vision and economic technology, lives change for the better. Such is thought of DG. Technology is changing very fast in this area and DG is expected to have significant impacts on electric power distribution.

Since technology, operating standards, and economics are not quite ready for broad applications of DG systems, why then include such a topic in a Long-Range Planning Guide? It has been included to challenge electric distribution planners for what is to come and for them to acknowledge that the technology and economics are there for some applications today.

With the high costs of large generating plants, transmission lines, substations, and distribution lines, we all need to be looking for alternative methods to providing electric power to our customers in the most economical method available. DG may fit that situation in some circumstances even today and the planning engineer needs to consider all resources that are available.

There are several different types and applications of distributed generation and they are listed as follows:

- Large-Scale,
- Medium-Scale,
- Small-Scale, and
- Residential/Commercial Solar PV.

Each category is summarized below to aid the system planner in identifying how and when DG could be applied.

2 LARGE-SCALE (500 kW–10 MW) DG (*Industrial*)

In general, application of large-scale DG systems will require some level of detailed engineering. These relatively large distributed generators will likely have a significant impact on long-range planning, particularly the larger applications. Many large-scale distributed generation applications have been implemented over the last several years, and many were cost-justified through the application of rate incentives, such as peak shaving, reserve or dispatchable capacity, and real-time or market-based pricing.

Recent, significant increases in fuel costs have brought into question the economic feasibility of many of these generators as long-range solutions. Volatility in both natural gas and diesel fuels, common fuels for this scale DG, has significantly reduced the cost-effectiveness of these applications. However, there are still significant potential savings with this size DG project in certain applications, particularly where load growth or short-term peak loading conditions require significant capital investments. Additionally, overall reliability of a feeder or transmission segment can be improved, when normally served by a radial source, if the generator is located near the load. Other considerations —such as tariffs, rate restrictions, all-requirement contracts, fuel costs, environmental impact, and O&M requirements—should also factor into the decision-making process. Generators of this size should at least be considered in some of these special cases as alternatives to capital-intensive projects, particularly reliability-based ones.

Similar considerations will have to be given to the ever-popular renewable resources, particularly wind power. Wind farms will likely be the quickest large DG applications to impact system planners. Today, most wind farms are larger than 10 MW; however, as popularity rises and costs decrease, there will be increased pressure to move to small wind farm applications. The biggest design factor of this size system will be its "back-feed" capability. In renewable-rich areas, and with proper incentives, there is the distinct possibility that these renewable sources may exceed local demand. In this case, the system planner must also consider line and equipment capacities and ability to manage bi-directional load flow on a day-to-day or hour-to-hour basis.

From strictly a planning perspective, the system planner will have to seriously consider the availability and predictability of renewable DG energy sources. Although renewable resources—such as wind and solar—are great at off-setting energy produced by burning fossil fuels, the variability in the "fuel" availability will be a challenge, particularly the farther out on the distribution system these medium DG sources are located. It is very likely that renewable resources can only be used to off-set or delay capacity improvements when they are combined with near real-time smart grid applications, such as load shedding.

3 MEDIUM-SCALE (50 kW–500 kW) DG (*Commercial*)

This DG size is probably the most commonly available engine-generator set today. They are quite common in many commercial and some industrial applications. Industries highly dependent on electrical power, and often required by law or economics to have generator backup, make up a considerable aggregated DG capacity base. Hospitals, prisons, fire protection, casinos, and even hotels often have full or near-full capacity generation on-site. In the late 1990s, there was a significant effort by the industry to utilize this unused capacity. Although there are successful projects utilizing medium-scale DG, deployment has not reached projections because of several hurdles, including the following:

- Limited rate support;
- Increasing fuel costs;
- Limited G&T price signaling;
- Limited communications and system control functions between the DG owner and the utility for large-scale assimilation with the distribution system;
- Equipment costs, especially for paralleling switchgear;
- Service interruption on lower cost, break-before-make transition switchgear; and
- Operation and Maintenance cost and expertise.

As in large-scale systems, medium-scale DG may be able to delay capital-intensive improvements, but more likely on a distribution system level, provided that the DG source is very reliable. If a DG system is going to be included as a solution for a distribution system limitation, the system planner may need to require that the DG be directly assigned to interruptible loads. Otherwise, system performance may fall outside of acceptable ranges.

Application of medium-sized renewable DG sources will likely lag behind large-scale DG sources by a few years. However, if economies of scale apply to the manufacturing of renewable products, then medium-sized applications will become more commonplace. In renewable-rich areas, the aggregate of medium-sized DG projects on a feeder, in effect, may become similar to a large-scale DG source. In this case, many of the large-scale DG issues apply. If only one or two medium-sized renewable DG sources are located along a distribution feeder, then the traditional DG considerations above will apply, with one likely caveat. Most renewable DG applications require grid power for excitation of the generator, and they will most likely require parallel operation. Parallel operations with the grid—even in medium-scale applications—creates a host of new design considerations, particularly with respect to bi-directional load flow, voltage regulation, and sectionalizing.

4 SMALL-SCALE (1 kW–50 kW) DG (*Residential*)

Small-scale DG is currently very limited. Most DG of this size will be either residential or small commercial applications. In general, these applications operate more as a load off-set or reduction rather than as a generation source. Renewable energy applications such as solar are the most likely candidates in this category. To date, there has been more debate than deployment on these DGs, although popularity continues to rise. Most current solar applications interface via an inverter, which monitors the distribution system for outages and turns off in the event of a grid outage.

With the adoption of IEEE and UL standards, there is less and less operational and sectionalizing concern over these small DG applications, although the debate is not over. It will take a significant penetration of these DG applications to have a significant impact from a system-planning perspective. If anything, there will be more of a financial impact from small-scale DG applications since they are effectively reducing load. As with other recently set goals—such as energy efficiency and inclining block rates—small-scale DG will have more of an impact on the load projection aspect of system planning. Again, the biggest factor of concern is the predictability of the impact of the small DG or other load-reducing smart grid application.

As an example, an area may exist on a feeder where solar panels are installed on all new houses. On a normal, warm, sunny day, solar panels would likely offset a considerable amount of air conditioning load. However, an event as simple as a cloudy weather front moving through would immediately reduce solar output, producing an aggregate affect equivalent to cold-load pickup since there would be considerable lag in the thermal response of the homes cooling down from the cloud cover. Given that battery storage is considerably more expensive and maintenance intensive, it is less likely that energy storage will be implemented with early residential inverter systems.

Again, the system designer must take into consideration the impact of even small DG effects on the distribution system when they are adopted on a large scale. Incentive programs pushed by federal mandates may accelerate the deployment of such systems. Federal mandates such as renewable portfolio standards appear to have little to do with economics and may, in fact, impact even distribution planning sooner than expected.

5 RESIDENTIAL AND COMMERCIAL SOLAR GENERATION

One of the greatest potentials for distribution system and power supply is the development of small solar generators less than one megawatt in size. In most of the United States, there is very good availability of solar energy during peak summer times. Extensive addition of solar generators by residential and commercial consumers would reduce the requirement for new large generator construction, as well as reduce major improvements on distribution systems (e.g., major three-phase circuit rebuilds, substation upratings, etc.). Currently, power suppliers are realizing such potential and are developing generation purchasing policies that will pay solar generator installers from 12 to 20 cents per kilowatt-hour with contracts lasting up to ten years. As more and more power suppliers realize this potential, the addition of solar generators will greatly impact distribution system planning and will need to be considered when evaluating future capital requirements for long-term electric system needs.

The key to the situation is the quality, reliability, and costs of the equipment being manufactured. If quality and reliability can be assured by industry and governmental long-term warranties, and if costs continue to decline as the demand for such generation occurs, the solar generation option will play a very important role in future planning of electric distribution systems.

6 CONCLUSION

As technology expands and economics drives the market, DG is sure to have an impact on electric power distribution in the very near future. As constraints continue in the building of more large generating plants, transmission lines, substations, and distribution lines, DG is sure to become more and more economical.

Power suppliers and distribution cooperatives are encouraged to work closely together to develop policies that will encourage this renewable resource, one which will contribute significantly to the reduction of capital funds to increase system capacity as the demand for electric energy grows.

APPENDIX 5
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