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Electrical Utilities Model for Determining Electrical Distribution Capacity

Electrical Utilities
DynCorp Tri-Cities Services, Inc.

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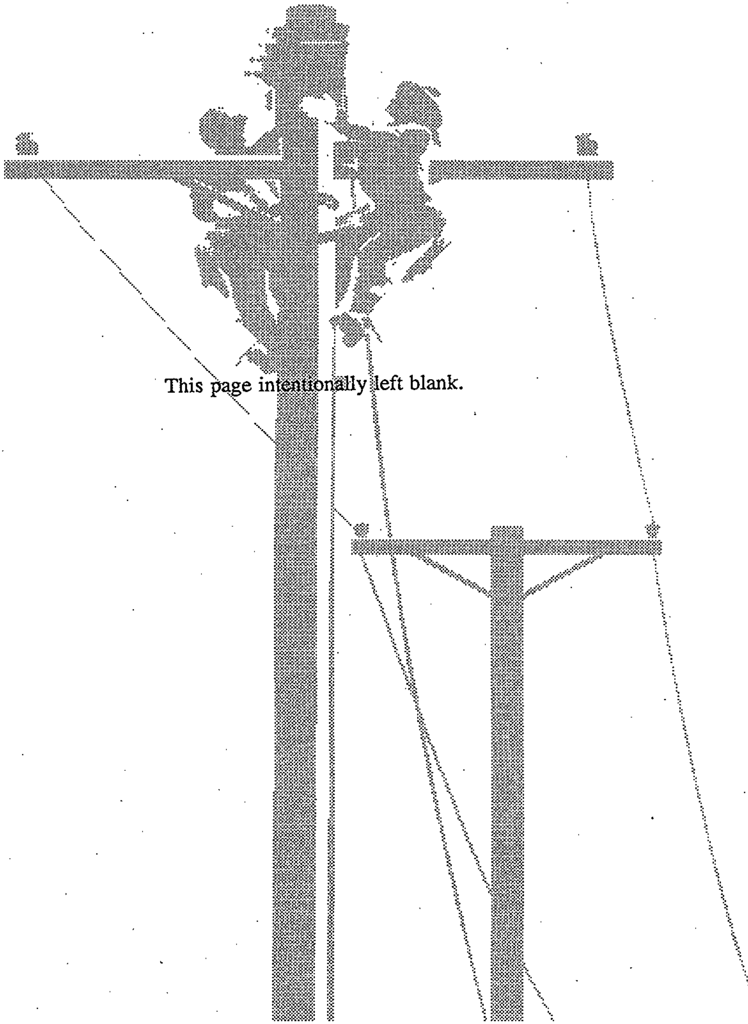

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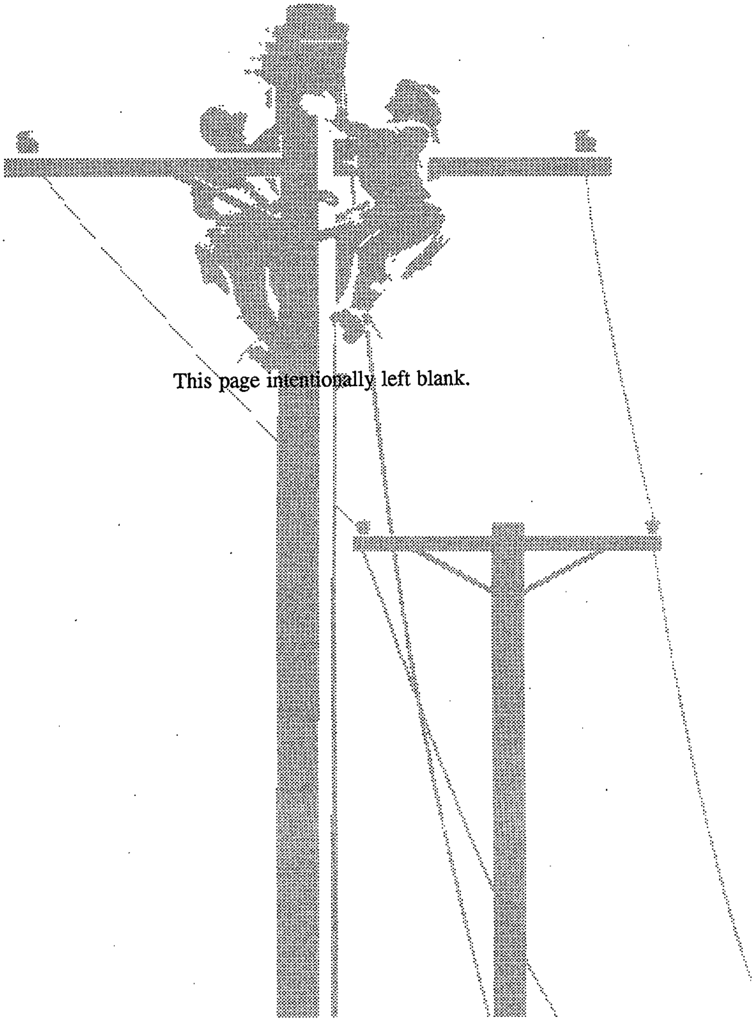

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ELECTRICAL UTILITIES MODEL FOR DETERMINING ELECTRICAL DISTRIBUTION CAPACITY

TABLE OF CONTENTS

Page

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

Page

LIST OF APPENDICES

Page

LIST OF FIGURES

LIST OF TABLES

ELECTRICAL UTILITIES MODEL FOR DETERMINING ELECTRICAL DISTRIBUTION CAPACITY

1.0 EXECUTIVE SUMMARY

1.1 Introduction

In its simplest form, this model was to obtain meaningful data on the current state of the Site's electrical transmission and distribution assets, and turn this vast collection of data into useful information. Major data inputs and outputs selected for the model included:

Inputs	Output
Annual recurring maintenance activities Backlog activities Upgrades and improvements Decommissioning tasks Customer service activities and requirements Condition and capacity of transmission and distribution system	Distribution and capacity, staffing, material, and equipment forecasts

The task presented many typical obstacles, such as:

- Asset information, while available, was not organized in a fashion convenient for the compilation of this document.
- The transmission and distribution network was very diverse and encompassed a variety of types and designs of structures, and dozens of types or designs of components.
- Average line age was approaching 35 years, with the oldest line over 50 years.

Existing documentation, including studies, memos, and letters, was used during the research of this model in an effort to better utilize taxpayers dollars.[1]

[1]Refer to Appendix A for a list of references used during compilation of this model.

The resulting product is an Electrical Utilities Model for Determining Electrical Distribution Capacity which provides:

- current state of the electrical transmission and distribution systems
- critical Hanford Site needs based on outyear planning documents
- decision factor model.

This model will enable Electrical Utilities management to improve forecasting requirements for service levels, budget, schedule, scope, and staffing, and recommend the best path forward to satisfy customer demands at the minimum risk and least cost to the government. A dynamic document, the model will be updated annually to reflect changes in Hanford Site activities.

1.2 Proactive Reengineering

DynCorp Electrical Utilities, with centralized control on a pay-as-you-use cost distribution, provides safety and economy that cannot be matched by decentralization to the programs, as well as timeliness/responsiveness that cannot be matched through outsourcing. This was demonstrated by the aggressive, FY 1996 cost reduction initiatives implemented by Electrical Utilities which significantly reduced staffing and costs. The group's allocation of Sitewide assessments, including occupancy, dosimetry, contracts, medical, and fleet, were challenged. A review of labor liquidation practices confirmed that most services provided by Electrical Utilities are appropriately borne by the entire Site. However, as some job requests are attributable to the budget of a particular facility, labor and materials required for particular facilities or projects are now charged directly to that project or facility, including 24-hour electrical dispatcher coverage and escort/standby services. The maintenance program was analyzed and compared to industry practices. Critical loads were identified and maintenance reduced where impact of outages was low. The work management process was analyzed, and the procedure simplified, saving time and money. This methodology also aligns with Fluor Daniel Hanford, Inc., performance measures regarding forecasting economies, as well as the DynCorp mission of optimization of Site support service and rates.

The group's efforts were commended by the Department of Energy, Richland Operations Office (DOE-RL) in re-engineering the operating methodology while continuing to maintain a safe, reliable and cost-effective utility service. Concurrently, Department of Energy, Headquarters (DOE-HQ) consultants concluded that Electrical Utilities had capabilities and knowledge which appeared to be unusually good for this type of facility, and staffing levels were reasonable.

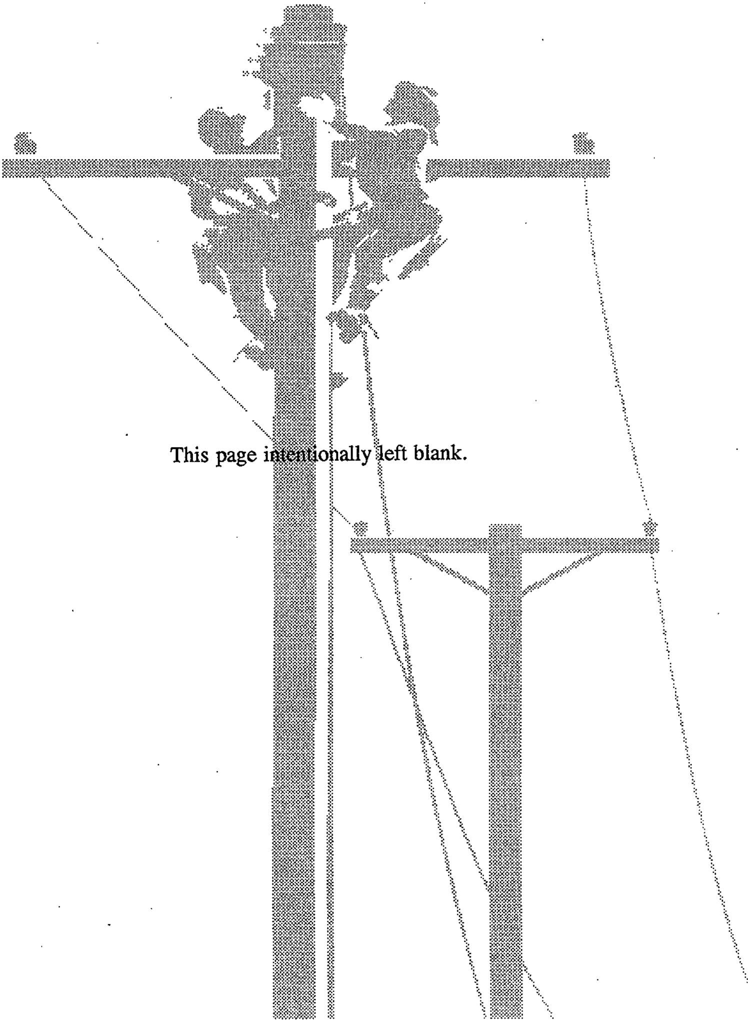
1.3 Recommendations

Electrical Utilities management believes that safe operation, low rates, core technical strengths, and excellent customer service will distinguish Electrical Utilities as the preferred supplier at the Hanford Site.

Capital investments and operation and maintenance expenditures must be minimized to hold down electric rates, and Electrical Utilities continues to hold down costs to remain competitive. Emulating commercial practices, Electrical Utilities has moved away from traditional time- or condition-based maintenance cycles and adopted a more reliability-based maintenance program without jeopardizing personal and system protection activities. Although an experienced staff is the single most important factor in maintaining reliability, expenses are also kept in check with reduced staffing levels. However, if Electrical Utilities cuts costs too far, the ability to supply reliable power to customers will be jeopardized. The organization's success will hinge on the ability to balance capital investment with appropriate system maintenance expenditures.

Electrical Utilities will continue to evolve in response to the changing utility environment, strengthening its foothold in the competitive marketplace, while focusing on efficiency and customer satisfaction by:

- determining when existing substations are no longer cost effective to operate
- submitting requests and budgets to deactivate substations with a corresponding decrease in backlog maintenance and infrastructure
- assessing the need for alternate routings when nuclear safety criteria or high reliability for long term experiments are no longer required
- increasing remaining substation capacity utilization
- pursuing marketing opportunities resulting from electric utility deregulation
- continuing to move toward best commercial practices where allowed by DOE requirements and company policies
- applying a comprehensive review of facility utility requirements to Electrical Utilities preventive, predictive, and corrective maintenance to ensure physical asset availability for planned use
- pursuing energy savings opportunities within the Utilities division.



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2.0 GOAL

2.1 Goals

- Operate the electrical utility system in a safe manner.
- Maintain operation and maintenance rate as low as reasonably achievable to remain competitive with local area utilities while providing needed services at an acceptable reliability level. Use accepted industry standard practice of cost per kilowatt hour format to measure performance.
- Provide additional services as requested by customers on a direct funded, work order basis beyond those which a utility routinely provides.
- Maintain core infrastructure in order to continue to meet Site mission.
- Continue to move toward best commercial practices as allowed under DOE rules and company policies.

2.2 Objectives and Strategies

The primary objective of Electrical Utilities is to ensure that safe electrical energy is available where needed to support clean up activities on the Hanford Site. The secondary objective is to reduce the costs associated with providing the electrical energy to the activities. Strategies to achieve these objectives include:

- Maintain those elements of the electrical transmission and distribution system that are required for present and future cleanup activities on the Hanford Site.
- Modify or upgrade the system where changes in the electrical demand and/or consumption and a cost benefit analysis indicates that a cost savings can be realized.
- Expand the system capabilities/capacity in support of new projects where required and funded by the benefitting project.
- Reduce infrastructure where no need exists, and personal and system protection activities will not be jeopardized.

2.3 Performance Measure

Hanford budgetary and management priorities now require allocation of utility costs in accordance with demand for resources, promotion of efficient resource use practices, and a general approach to infrastructure issues that emulates private sector practices. Electrical Utilities' present liquidation method represents a commercial, businesslike approach to cost recovery of the cost of buying electrical power plus the distribution cost associated with operations, engineering, and maintenance of the transmission and distribution systems. Both costs are currently transferred to the various programs by billing on a metered or estimated basis.[2]

Historically, the cost of providing power to the Hanford Site has been higher than rates charged by local and other U.S. utilities to commercial facilities (see Fig. 2-1) due to:[3]

- a transmission and distribution system spread over a large geographical area (560 square miles) with a low and gradually decreasing density customer base to cover costs

- special capacity vs. utilization considerations related to the need to maintain 100 percent continuity of service in response to customer needs

- security and safeguard measures required to protect national assets

- DOE and government contractor requirements governing conduct of operations, maintenance, worker and customer safety

- protection measures related to working around hazardous and radioactive facilities and contaminated areas.

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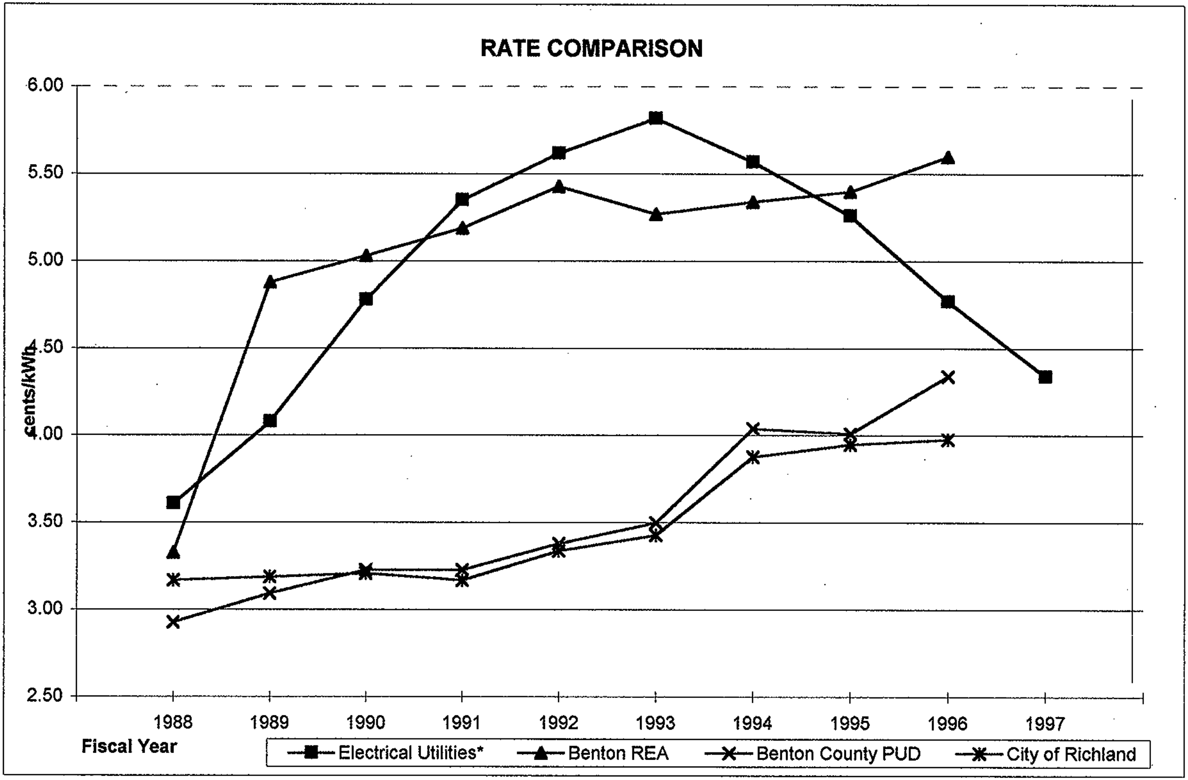
[2]Estimates are adjusted at beginning and mid-fiscal year. All customers are in one rate classification. Capital costs are not included.

[3]Comparisons between Electrical Utilities and other electrical utilities and even other DOE site utility organizations should be done with caution as each utility has unique service territory characteristics, customer loads, and organizational structures which may influence the expense ratios. No other DOE site has an electrical utilities system; rather, other DOE sites are similar to industrial campuses using industrial maintenance electricians.

Utilities are shaped significantly by the culture of the customer, and Electrical Utilities is certainly no exception. At best, the transmission and distribution system could only be 50 percent utilized to provide 100 percent redundancy at selected facilities. Previous studies attempted to compare Electrical Utilities' maintenance and operation costs to a 1.2 cents per kWh operations and maintenance (O&M) rate, a value based upon utility industry practice and similar to the average 1.17 cents per kWh O&M cost (excludes production and sales costs) from a survey of 160 major investor owned electric utilities recently released by the Utility Data Institute. However, investor owned utilities don't have to comply with DOE radiation requirements and maintain 100 percent redundancy at selected facilities. Investor owned utilities will provide additional services but at extra cost. Survey information obtained from Federal Electrical Regulatory Commission (FERC) Form No. 1 reports submitted on an annual basis.



*Electrical Utilities actual rate (total costs obtained from cost account reports in the Financial Data System divided by total kWh consumption obtained from BPA wholesale power bills).

FIG. 2-1

A significant decrease[4] in the Electrical Utilities rate occurred during FY 1996 (see Fig. 2-1). Two activities, achieved during the month of May, were responsible for the dramatic reduction:

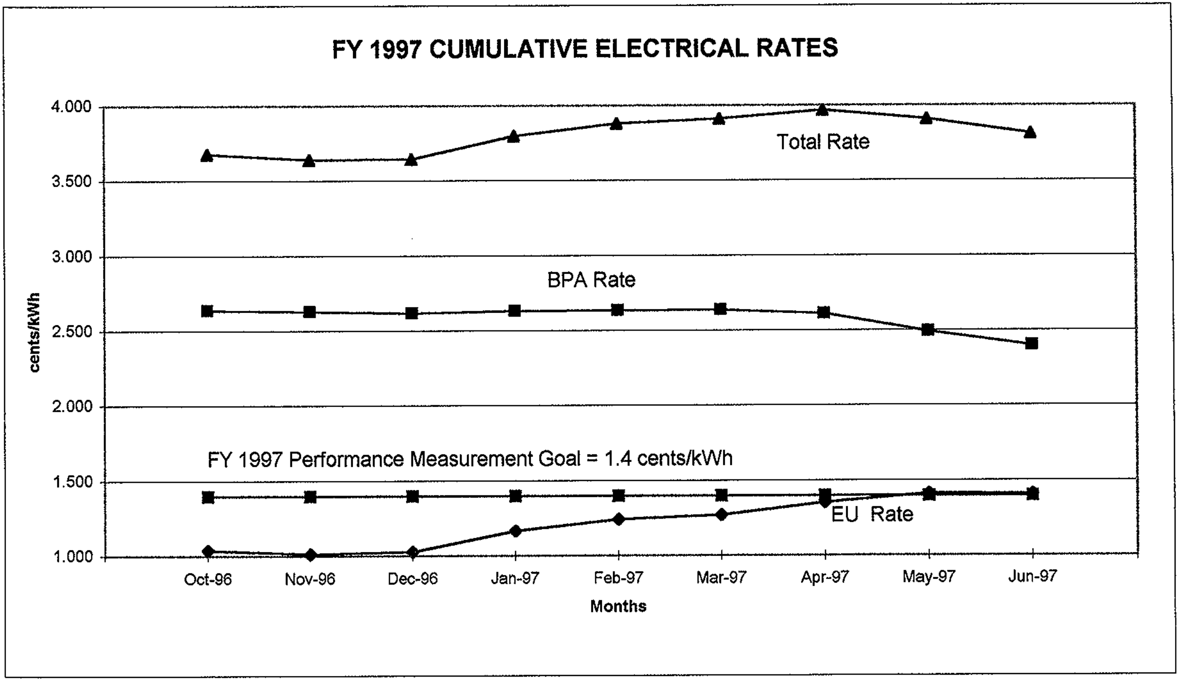
- an aggressive cost reduction campaign implemented by Electrical Utilities,

- an evaluation of a different rate structure. Assessments such as occupancy, landfill, transit, site services (janitor, weed and pest control, etc.), fire systems, BPA allocations, and PCB contract work, were excluded because the costs would remain even if the Electrical Utilities function was outsourced to another utility.[5]

The FY 1997 performance measurement goal for Electrical Utility operation and distribution costs is 1.4 cents per kWh. Through June 1997, this rate is 1.412 cents/kWh, and the cumulative average cost of purchasing BPA power is 2.402 cents/kWh, for a total cost of 3.814 cents/kWh to the Site user (see Fig. 2-2).

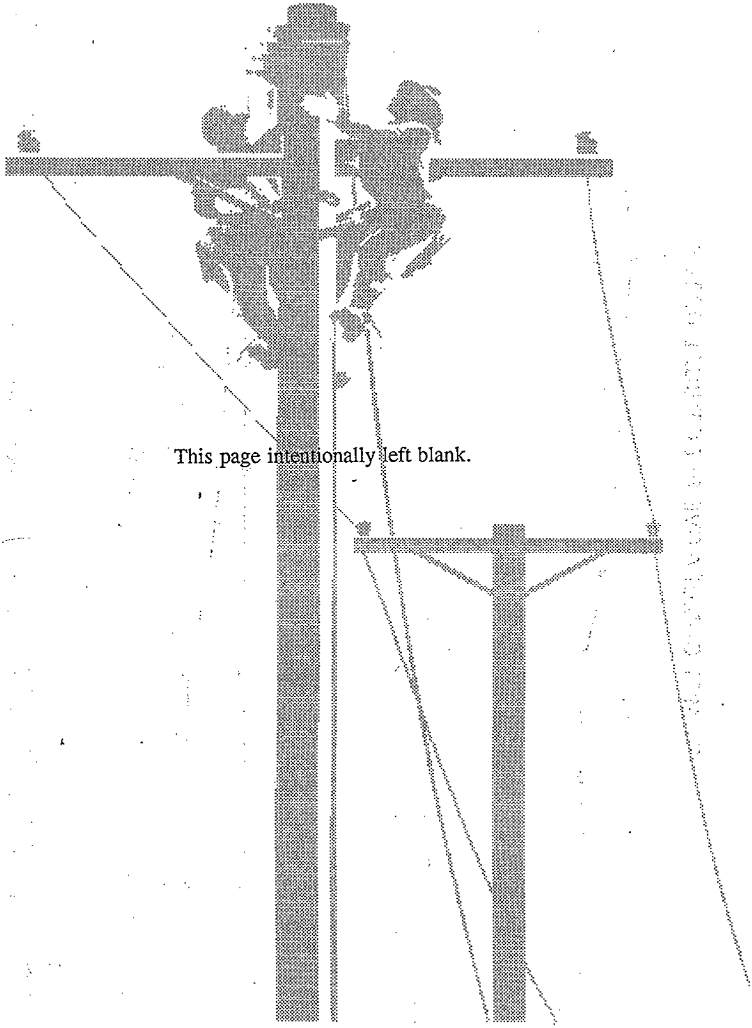
[4]The FY 1996 Electrical Utilities rate was approximately 9 percent less than the FY 1995 rate, the largest annual drop of the downward trend which began in FY 1994.

[5]These costs are excluded from the Electrical Rate calculations based upon instructions provided from W. A. Rutherford, Director of Site Infrastructure Division, DOE-RL, dated 3/8/96, Ref. No. 96-SID-009.



Notes: The adjusted normalized, cumulative Electical Utilities rate is used for the performance measurement cost. Adjusted costs are derived by excluding authorized assessments from total Electrical Utilities' costs (figures obtained from cost account reports in the Financial Data System), less wheeling credits obtained from the BPA wholesale power bill. The adjusted costs are normalized using rate calculations based upon the number of days in the month for the BPA cycle and the number of days in the DynCorp fiscal month, allowing costs to match services by creating a daily rate for Site costs. Rates are cumulative by fiscal year.
Total rate = BPA plus EU rates.

Fig. 2-2



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3.0 REGULATORY REQUIREMENTS

3.1 Standards, state and federal regulations, and U.S. Department of Energy orders used to measure system performance and condition

Electrical Utilities performs work under the requirements and guidance contained in the National Electrical Safety Code as implemented by the Washington State Electrical Safety Code, DOE Orders and Directives, Project Hanford Management Contract and DynCorp policies and procedures, referenced consensus standards, and self-imposed best management practices. Criteria for operation are also established in the "Policy of Hanford Electrical Power Management Program," Rev. 3, May 23, 1986. The primary goal of implementing these requirements is to maintain a highly reliable delivery system that is responsive to the facility customer's needs, with emphasis on safety and proper utilization of resources. Some of these requirements are in addition to those requirements listed in the Project Hanford Management Contract, Part III, Section J, Appendix C and are considered important for determining the size of the baseline workforce. Some matrixed professional support is necessary to verify compliance with these regulations and requirements. Noncompliance to some standards could result in fines and penalties.

- DOE Order 232.1, Occurrence Reporting and Processing of Operations Information (9/30/95), establishes a DOE system for identification, categorization, notification, analysis, reporting, followup, and closeout of occurrences.

- DOE Order 430.1, Life Cycle Asset Management (8/24/95), directs the planning, acquisition, operation, maintenance, and disposal of physical assets as valuable national resources and the stewardship of these physical assets be accomplished in a cost-effective manner to meet the DOE mission.

- DOE Order 4330.2D, In-House Energy Management, provides for the management of energy use in DOE owned and leased facilities, and vehicles and equipment.[6]

- DOE Order 5400.1, General Environmental Protection Program, Section 1.4.B, Waste Minimization Efforts to Reduce the Volume and Toxicity of Generated Wastes, regulates compliance with applicable Federal, State, and local environmental protection laws and regulations, Executive Orders, and internal Department policies.

[6]DOE Order 4330.2D has been canceled and replaced with DOE 430.2, "In-house Energy Management", as of June 13, 1996. This may not be reflected in the FDH-DYN contract, but should be updated.

- DOE Order 5480.19, (Except Chapter 9), Conduct of Operations for DOE Facilities, provides requirements and guidelines to develop directives, plans, and/or procedures relating to the conduct of operations at DOE facilities which should result in improved quality and uniformity of operations.

- DOE Order 6430.1A, Chapter VIII - General Design Criteria, Exterior Electrical Systems, and Chapter XIII - Energy Conservation and Use of Renewable Energy Sources, 4-6-89, provides general design criteria or use in the acquisition of the Department's facilities and to establish responsibilities and authorities for the development and maintenance of these criteria.

- Federal Acquisition Regulation, Part 41, Acquisition of Utility Services, Feb. 27, 1995, prescribes policies, procedures, and contract format for the acquisition of utility services not produced, distributed, or sold by another Federal agency.

- 29 CFR 1910, Occupational Safety and Health Standards for General Industry, establishes safety equipment requirements, requires procedures and guidelines, and outlines training requirements.

- 29 CFR 1904.1-.22, Recording and Reporting Occupational Injuries and Illnesses, provides for recordkeeping and reporting by employers covered under the Occupational Safety and Health Act of 1970 as necessary or appropriate for enforcement of the Act, for developing information regarding causes and prevention of occupational accidents and illnesses, and for maintaining a program of collection, compilation, and analysis of occupational safety and health statistics.

- 40 CFR 265, Basic Resource Conservation and Recovery Act (RCRA) of 1976 Operating Requirements, addresses general operating requirements for owners and operators of facilities that use tank systems for storing or treating hazardous waste, and specifies hazardous wastes or treatment reagents must not be placed in tank if could cause tank system to rupture, leak, or otherwise fail. Requires contingency plans to minimize hazards to human health or environment from fires, explosion, or any unplanned sudden or non-sudden release of hazardous waste constituents which could threaten human life or the environment.requires appropriate controls and practices to prevent spills and overflows. Provides for responses to leaks or spills and disposition of leaking or unfit-for-use-tank systems.

- 40 CFR 372.30, Emergency Planning and Community Right-To-Know Act (EPCRA) Reporting Requirements, toxic chemical release reporting and community right to know reporting requirements and schedules for reporting.

- 40 CFR 761, Federal Polycholorinated Biphenyl Regulations, involves inspection of PCB Transformers, regulates manufacturing, processing, distribution in commerce, and use of PCBs and PCB items, and authorizations for non-totally enclosed PCB activities.

- WAC 173-303, Dangerous Waste Regulations, implements chapter 70.105 RCW, the Hazardous Waste Management Act of 1976 as amended in 1980 and 1983, and implements in part, chapter 70.105A RCW, and Subtitle C of Public Law 94-580, the Resource Conservation and Recovery Act

- WAC 296-45, Safety Standards for Electrical Workers (1/97), contains rules for electrical workers as adopted under the Washington Industrial Safety and Health Act of 1973 (Chapter 49.14 RCW). Includes minimum leadwork requirements.

- 10 CFR 436, Federal Energy Management and Planning Programs, 1-1-85, Subpart A - "Methodology and Procedures for Life-Cycle-Cost Analyses"; Subpart B - "Procedures for Preliminary Energy Audits,"; Subpart C - "Guidelines for Building Plans"; and Subpart F - Guidelines for General Operation Plans" (including an Emergency Conservation Plan).

- Executive Order No. 12003, July 20, 1997, relating to energy policy and conservation, requires the development of guidelines for and the submittal of 10-year plans for energy conservation with respect to Government buildings, and establishes requirements for energy audits and goals for reduction of energy use in federal buildings.

- National Electrical Code, NFPA 70, contains provisions considered necessary for safeguarding persons and property from hazards arising from the installation of electric conductors and equipment within or on structures, that connect to the supply of electricity, installations of other outside conductors and equipment on the premises, installations of optical fiber cable, and installations in buildings used by the electric utility.

- National Electrical Safety Code, provides practical safeguarding of persons during the installation, operation, or maintenance of electric supply and communication lines and associated equipment, as well as basic provisions that are considered necessary for the safety of employees and the public under the specified conditions.

- Energy Policy Act of 1992 (Public Law 102-486), contains new efficiency provisions for federal facilities and fleets, and increases use of renewable energy and alternative fuels.

- Bonneville Power Administration 1996 Wholesale Power Rate Schedules and General Rate Schedule Provisions, October 1, 1996, describes the priority firm power rate (schedule PF-96A) for electricity purchased under the power sales contract at the Hanford Site.

- Agreement and Pension and Insurance Agreement Between Fluor Daniel Hanford Company and Hanford Atomic Metal Trades Council, (FDH 1997) ensures adherence to jurisdictional agreements, outlines union business activities, and determines wage rates. Before work (e.g., Electrical Utilities) is contracted out, it must be subjected to a "turn down" process. This process does not consider cost as the sole criteria for turndown. Schedule and shop capabilities are also used to evaluate the request for work consistent with the contract.

The Institute of Electrical and Electronics Engineers and the Washington Safety Health Act require work to upgrade facilities and personnel protection, respectively. The American Society of Mechanical Engineers and American National Standards Institute also have national standards requirements that effect Electrical Utilities procedures, qualification, and certification of procedures and personnel maintenance and retention of records.

3.2 Marketing Opportunities

Although marketing opportunities for Hanford resulting from electric utility deregulation and the ability to evaluate alternate power generation resources are still years away, there are two basic options:

- DOE-RL is a federal agency and receives priority firm power from BPA. This is the same wholesale rate schedule that public utility districts and municipalities purchase power from BPA for resale to their consumers. The present 20-year contract, established in 1982 and lasting until 2002, has rate schedules which are revised every two to five years. Months prior to the conclusion of the existing contract, DOE-RL will be able to negotiate a power contract with one or more electrical providers. Other local utilities have already initiated up to 15 percent of their power requirements with other than BPA with a corresponding savings.[7]

- Washington state guidelines for the transition to deregulation have yet to be set by the state legislature. Eventually, other electrical utility companies will have the opportunity to wheel power through the Hanford system, providing Electrical Utilities with another means to liquidate costs (offset reported rate) through new wheeling revenues.

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[7]However, modest increases in transmission and distribution expenses are projected through the year 2000 for 120 major U. S. investor-owned electric utilities, according to research compiled by TECC Group, Inc., Littleton, Colorado, with the strongest increases projected for the Southwestern and Midwestern states and the West Coast.

4.0 BASELINE OPERATIONS

4.1 Mission

The mission of the Electrical Utilities function is to provide electrical power transmission and distribution services by creatively adapting to meet the needs of the Hanford Mission. The function's vision is to be valued as a resource that is customer oriented, responsive, cost efficient, safe, and highly effective.

4.2 Workforce Organization

Electrical Utilities staff are responsible for the operation, administration, maintenance, upgrade activities, engineering, and configuration management associated with the DOE-RL owned Hanford electrical transmission and distribution system. The organization is not a typical electrical utility, but an integral part of the Hanford mission, challenged to ensure continuity of a highly reliable service. In addition, the specially trained and equipped work force provides a pool of high voltage expertise in demand for related customer work ordered services, such as 24-hour dispatch, facility electrical maintenance, lineman and electrician standby support, rubber goods testing, and special outage support for other plant operations. Electrical Utilities also supports operations of the Hanford Site polychlorinated biphenyl (PCB) storage for disposal facility, and handles and processes non-radiological PCB wastes for off-Site shipment. A list of driving requirements for Electrical Utilities activities is in Section 3.0.

Major services provided by Electrical Utilities have historically been grouped by Operations, Administration, and Maintenance and Management support. Other organizations or companies provide support to Electrical Utilities which must be forecasted and budgeted as well. For FY 1997, the workforce is comprised of 13.8 FTE bargaining unit, 18.3 FTE exempt, and 3.0 FTE nonexempt personnel, or a total of 35.1 FTE.[8] Work ordered customer service activities, not included in the Electrical Utilities cost account plan, fund an additional 10.3 FTE. See Appendix B.

<u>4.2.1 Operations</u>. Operations includes such areas as operations management and supervision, electrical system configuration control, systems protection engineering, electrical engineering, and administrative support. Specific activities include system design and modification, electrical equipment standard specification and development, project reviews, permit development and processing, site selection analysis, Engineering Change Notice (ECN) development, and protective coordination studies.

Administrative support provided for a variety of programs includes report preparation, data analysis, Corrective Action Management, safety programs (i.e., confined space,

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[8]Full time equivalent figures which include 1.3 FTE exempt and 0.7 FTE bargaining unit Support from Others.

fall protection, asbestos, etc.); conducting accident investigations and critiques; performing root cause analysis and risk evaluations (PPG), and preparing occurrence\event reports; developing Job Safety Analysis and Energized Work Permits; providing oversight to the working-level procedure program, including the role as the procedure coordinator; directing the Lock-Tag program and serving as Lock-Tag Administrator; and interfacing with technical training and other support organizations.

Also included under these services is the operation of the Supervisory Control and Data Acquisition (SCADA) system, which monitors and provides status and alarms on problems associated with the transmission and distribution system. Electrical Utilities operates a 24-hour manned central dispatch station, which provides a single point of contact for coordination of all electrical activities on the transmission and distribution system and outage notification to facility representative during off-shift hours. The SCADA system allows the dispatcher to change electrical routings remotely through the primary and secondary substations in the event of an outage or failure.

For FY 1997, the Operations group involved 8.8 FTEs, as well as 3.1 FTE in direct funded activities. See Appendix B.

4.2.2 Administration. Administration includes the electrical utilities manager, administrative clerical support, technical support management and supervision, energy management engineering, bargaining unit energy support, and plant engineering administration and technical support.

Specific support activities include meter readings, review of billings for completeness/correctness, individual facility billing, electric usage forecasting, consumption tracking, and energy reduction (load curtailment) planning and support, meter design and repairs, financial support, data analysis, programmatic support, and self-assessments. In addition, the Administrative group compiles and prepares the Hanford Site Quarterly Energy Conservation Performance Report and the annual Site energy report for DOE-RL, and evaluates energy savings opportunities within the Utilities division.

For FY 1997, the Administration group involved 5.4 FTEs, as well as 0.1 FTE in direct funded distribution activities. See Appendix B.

4.2.3 Maintenance and Management Support. Activities include bargaining unit supervisory support, clerical support, plant engineering support, maintenance on transmission and distribution equipment; maintenance associated with the SCADA system and other instruments; emergency response support to power outages to restore power and conduct necessary repairs; aerial support to various electrical crews and plants/facilities as required; maintenance support to electrical utilities substations and associated electrical equipment (kWh); test, calibrate, and repair over 300 protective relays, 600 kilowatt hour meters, and 100 field data acquisition system (FDAS) units; work management planning and scheduling, environmental compliance, and material coordinator activities. Other activities include scheduling building outages, electrical switching (230 kV, 115 kV, 13.8 kV, and 2.4 kV), meter reading, service tie-ins, facility support (elevated work), first response to PCB/oil spills and hazardous waste management, transformer decontamination and decommissioning/removal, and double isolation for facility lockouts-tagouts.

The maintenance activities described above tend to fall within three main categories:

- **preventive maintenance**, including both routine preventive and predictive maintenance activities, which tend to be reasonably constant and predictable from year to year and are necessary to maintain a safe and reliable electrical infrastructure system in support of programmatic activities. As a result of a maintenance activity analysis conducted in FY 1995/96, activities which did not impact the life cycle of the transmission and distribution system or the health and safety of employees were eliminated.

- **corrective maintenance**, including repair of failed or malfunctioning equipment, system, or facility to restore the intended function or design condition. This maintenance does not result in a significant extension of the expected useful life.

- **facilities support**, including both preventive and corrective maintenance from major programs and other Hanford Site contractors.

For FY 1997, the Maintenance and Management Support group involved 18.9 FTE as well as 7.1 FTE in direct funded activities. See Appendix B.

4.2.4 Support From Others. Services provided by other organizations or companies include design/drafting support, drawing maintenance, as-built and document control; chlorinator, janitor, pesticide, transportation, and weed control services; craft, software engineering, performance measurement, and training support; generator repair and traffic inspections; asbestos, hazardous waste, health physics technician, carpenter, fabrication shop, and excess material support. These activities tend to be reasonably constant and predictable from year to year.

For FY 1997, Support from Others involved 2.0 FTE. See Appendix B.

4.2.5 Customer Service Activities and Requirements. Based on commercial practice, Electrical Utilities workscope is limited to Electrical Utility specific facilities, systems, and reports. Additional services in support of and as requested by customers, beyond those routinely furnished by a utility, are provided by Electrical Utilities personnel on a direct funded, work order basis. During October 1, 1996, through June 15, 1997,[9] the group has in hand over 100 work orders resulting in 28.5 non-exempt, 4,451.5 exempt, and 8,119 craft hours, totaling 12,599 manhours, or 9.7 FTE. In comparison, the FY 1997 cost account plan for the same time period includes 3,763.8 non-exempt, 24,522.6 exempt, and 18,042.4 craft hours, totaling 46,328.8 manhours, or 35.7 FTE.[10] This demonstrates the cost account plan contains only 77 percent of the work to be performed by Electrical Utilities (see Fig. 4-1). Crews strive to meet the customer need dates 100 percent of the time and complete work orders to the negotiated budget. These indicators generally have a high correlation to the customer's satisfaction.

4.2.5.1 Project requests. Electrical Utilities crews provide switching support to provide safe work areas throughout the Site for subcontractors conducting repairs and modifications, energize new services in support of various projects, including new cleanup facilities, disconnect electrical service to facilities in timely support of deactivation and decommissioning activities, and support PCB oil shipments. Funding for these requests originates from each facility's budget.

Twenty-three FY 1998 Landlord Program Site Infrastructure projects remain within the current target funding level. Eight (35 percent) of the projects may potentially require Electrical Utilities crews. The estimated FTE requirements have been incorporated in the FY 1998 building blocks forecast included in this model.

Several other projects potentially involving Electrical Utilities crews have been identified from the activity descriptions in the Project Hanford Summary Schedule. The estimated FTE requirements have been incorporated into the forecasts included in this model.

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[9]Processing direct funded hours worked by each Electrical Utilities employee is a rather labor intensive process. To promote the most efficient use of time, employee productivity, and complete the Model by the DynCorp targeted milestone due date of August 29, the work order data compilation was performed during the third week of June.

[10]Full time equivalent numbers noted in section 4.2 and on Appendix B are average for the fiscal year. Work ordered customer service and Electrical Utilities cost account plan activities cannot be level loaded throughout the fiscal year. The amount of direct funded work versus cost account plan activities scheduled each month is based upon a variety of factors, including customer requests and weather. Most direct funded work is accomplished during the summer months, a time period which is not included in this data snapshot.

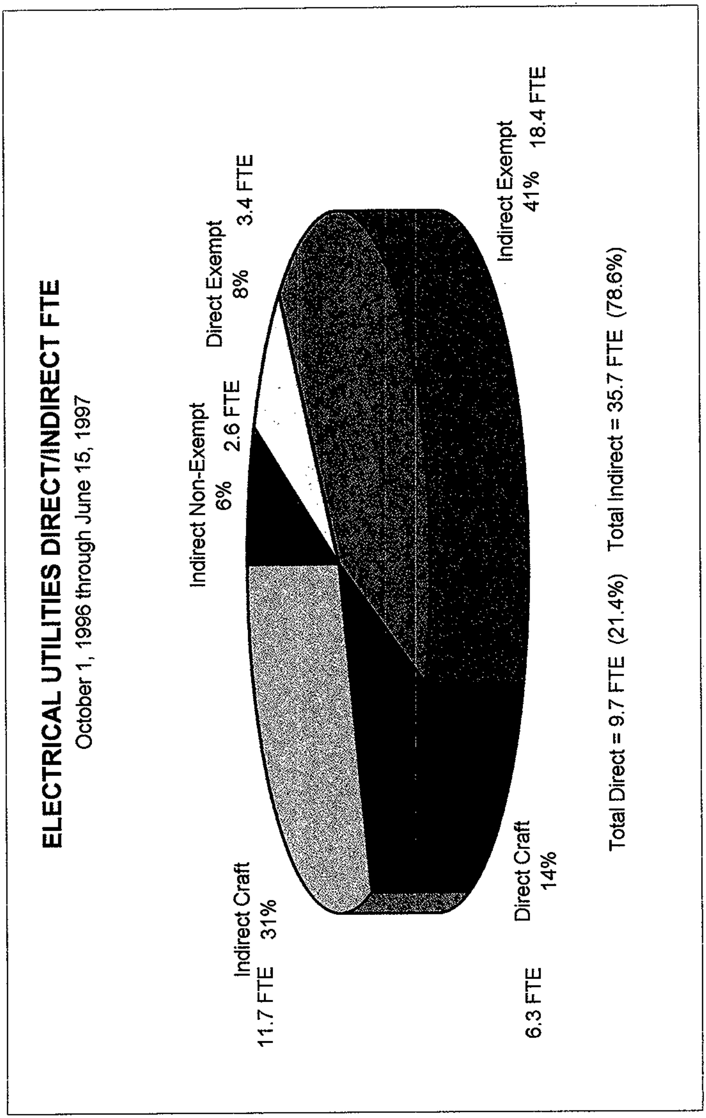

ELECTRICAL UTILITIES DIRECT/INDIRECT FTE
October 1, 1996 through June 15, 1997
Indirect Non-Exempt 6% 2.6 FTE
Direct Exempt 8% 3.4 FTE
Indirect Exempt 41% 18.4 FTE
Indirect Craft 31% 11.7 FTE
Direct Craft 14% 6.3 FTE
Total Direct = 9.7 FTE (21.4%) Total Indirect = 35.7 FTE (78.6%)

Fig. 4-1

4.2.5.2 Walk-in requests. In addition to known customer service activities, on-demand or level-of effort tasks must be allowed for in planning customer requirements, although the tasks are reasonably constant and predictable from year to year. This work may come from major programs, but historically comes from other Hanford Site contractors and includes outage support, relay and meter calibration, rubber goods testing, cable and transformer testing, PCB oil response, and other customer requested activities.

Using the activity descriptions in the Project Hanford Summary Schedule, Electrical Utilities management identified activities which may potentially involve Electrical Utilities crews and estimated the FTE requirements, which have been incorporated into the forecasts included in this model.

4.2.6 Future Work Organization. Following commercial practices, Electrical Utilities management is preparing to track costs by transmission and distribution categories. Enhanced tracking of transmission, distribution, and work for others costs will become available through a new work management[11] system to be implemented during FY 1998, and the data will be used in subsequent revisions of this model as a management tool to help determine appropriate future budget and staffing levels. An estimate of 30 percent transmission and 70 percent distribution has been factored into Appendix B. Actual percentages will be known when the new work management system becomes fully operational with sufficient data for analysis.

- Transmission categories include 151-B, 151-D, 151-N, 151-KW, 151-KE, 251-W, and 351 substations, as well as transmission lines, and help determine costs incurred by primary substations. System activities include: testing and/or repairing breakers, switchgear cubicles, switchgear bus, potential and current transformers, lightning arresters, kWh meters, protective relays, and emergency lights; and conducting visual and infrared inspections of underground vaults, aerial lines, cables, poles, towers, switching stations, switching devices, transformers, and coupling capacitors.

- Distribution categories include: the 100-B, 100-D, 100-N, 100-K, 200-E, 200-W, 300, and 600 Areas; 252-E, 252-W, 352-E, and 352-F substations; and a General classification, and will help determine costs incurred by Site areas and secondary substations. System activities include: testing and/or repairing breakers, switchgear bus, cables, switchgear cubicles, lightning arresters, kWh meters, potential and current transformers, protective relays, switching devices, and switching stations; and conducting visual and infrared inspections of underground vaults, aerial lines, and poles. General system activities

[11]The implementation of the new work management system (MAXIMO) is driven by RL 94-94, *Data Management Plans for Hanford Site Business Functions*, Rev. 0, Engineering Data Management Plan. During FY 1995, the pilot program was established and the data system requirements were fully defined and implemented on a limited scale.

include conducting visual inspections of first aid kits and fire extinguishers, and testing and/or repairing batteries, eye wash stations, hot line tools, and rubber goods.

- Work for others categories include the 100-B, 100-D, 100-K, 100-N, 200-E, 200-W, 300, 400, and 600 Areas, and help determine costs incurred and revenue generated by Site areas.

4.3 Economic transition needs

Some economic transition changes have already occurred and kWh adjustments incorporated into the Hanford distribution capacity. These include the Kaiser Aluminum contract, which will continue through August 15, 1999, and the enterprise companies which resulted from the 1996 Project Hanford Management Contract.

The Department of Energy has also committed to deliver up to 20 MW electrical power at 13.8 kV for each of the two Tank Waste Remediation System (TWRS) privatization facilities at each contractor's Site perimeter. Using the RL 230 kV transmission system to provide power to a new 230 13.8 kV substation is less costly, more reliable, maintainable, and operable, and will have less impact to the environment than other alternatives. The substation and distribution system to be built will provide the needed electrical service to the privatization facilities, as well as provide capabilities for further expansion to accommodate power needs of future facilities. A definitive electrical load estimate for the privatization facilities will not be known until the electrical data are received from the privatization contractor. Although definitive load data will be provided by the privatization contractor(s) after the contract award, it is anticipated that the TWRS Phase I privatization facilities will require 40 MW by 2003. The estimated manhour and power adjustments have been forecasted in Sections 6 and 7 of this model under Project W-503.

In addition, several potential needs have been identified by the Economic Transition Team. The following interest-only activities may occur prior to FY 2000:

- Washington State University is interested in 3745 A/B, 3745 B/C, or 3746/3746A. Anticipated load is comparable to 3706.
- A large manufacturer may use the 3714 building and require 15 kVA, 480 V and 2400 service.
- Temporary power will be needed for a crane in 333 South to remove the Lowe press.
- The 324 building may be commercialized (anticipate continued existing load).
- Crane use in the 1171 facility would increase if a railroad repair company becomes established with incremental power increases of 100 kVA.

- Depending on the outcome of the FFTF, the 400 Area buildings could be utilized either by the Port of Benton or in support of FMEF.

- The infrastructure also exists for a hazardous waste facility at the 616 building requiring a small, 40 kVA transformer.

These potential activities will not create any noticeable increases from existing manhour or power requirements.

Other commercial operations have expressed interest in locating in the vicinity of the Hanford Site, but in areas already designated by other utilities, such as the City of Richland, Benton County PUD, or Benton REA. In addition, cleanup and subsequent return of local control to some areas of the Hanford Site have the potential to generate non-federal industrial development. Final land use recommendations by a joint federal, state, local, and tribal planning council are due October 1997, a date outside the submittal parameter of this model. It is therefore premature to anticipate what impact these recommendations for effective use of assets no longer required by the federal government will have on Electrical Utilities.

5.0 BASELINE TRANSMISSION AND DISTRIBUTION SYSTEMS

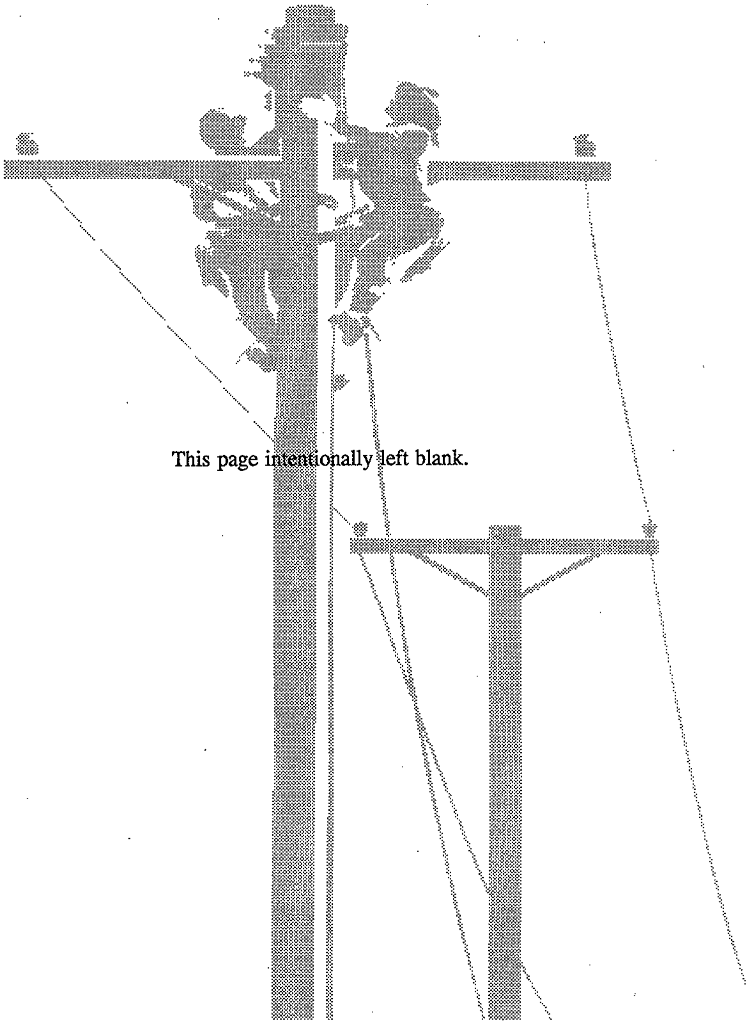
5.1 Background

The original Hanford Site electrical transmission and distribution system was installed in 1944. Spread over 560 square miles, the system is a fixed asset and cannot be reduced on a regular basis despite a low and gradually decreasing density customer base to cover costs. About 40 average megawatts (MW), with a peak of 60 MW of firm electrical power, is delivered to Hanford facilities under the special requirements for nuclear safety and is essential to Hanford Site customers and their ability to conduct Hanford mission specific activities. The system includes approximately 200 miles of transmission and distribution lines, as well as 11 primary substations, 165 (large, capital) transformers, 1600 distribution transformers, 900 transmission and distribution relays, 68 (large, capital) circuit breakers, 109 (large, capital) switches, 42 (large, capital) cubicles, and other equipment.

Approximately 97 percent of the Site's electrical power is purchased directly from the BPA. About 3 percent of the electrical power is supplied directly by the City of Richland to facilities in the 700 and 1100 Areas. The City of Richland also supplies power directly to the new Environmental and Molecular Sciences Laboratory (EMSL) and to the Hazardous Material Management and Emergency Response (HAMMER) facilities in the southern portion of the 300 Area. Less than 1 percent is supplied by the Benton County Public Utility District and the Benton Rural Electric Association.

Major upgrade projects to rebuild the system have taken place since 1978, including a program to eliminate PCB oils. However, a few components of the system are approaching the end of their useful lives. These will require replacement or decommissioning, and new extensions from the present system may be required to provide electrical power for future remediation activities. In addition, a demand profile change occurred due to the Site's revised primary mission from production to cleanup. Many of the large transformers and some small substations, which previously served active production facilities, are now drastically underutilized. Transformer energization losses may be reduced with properly sized, modern transformers. Deactivating substations will reduce energy losses with a corresponding decrease in backlog maintenance while increasing remaining substation capacity utilization. The appropriate timing for downsizing electrical systems as the cleanup activities progress needs to be determined.

Figure 5-1 shows the Hanford Site transmission and distribution system.



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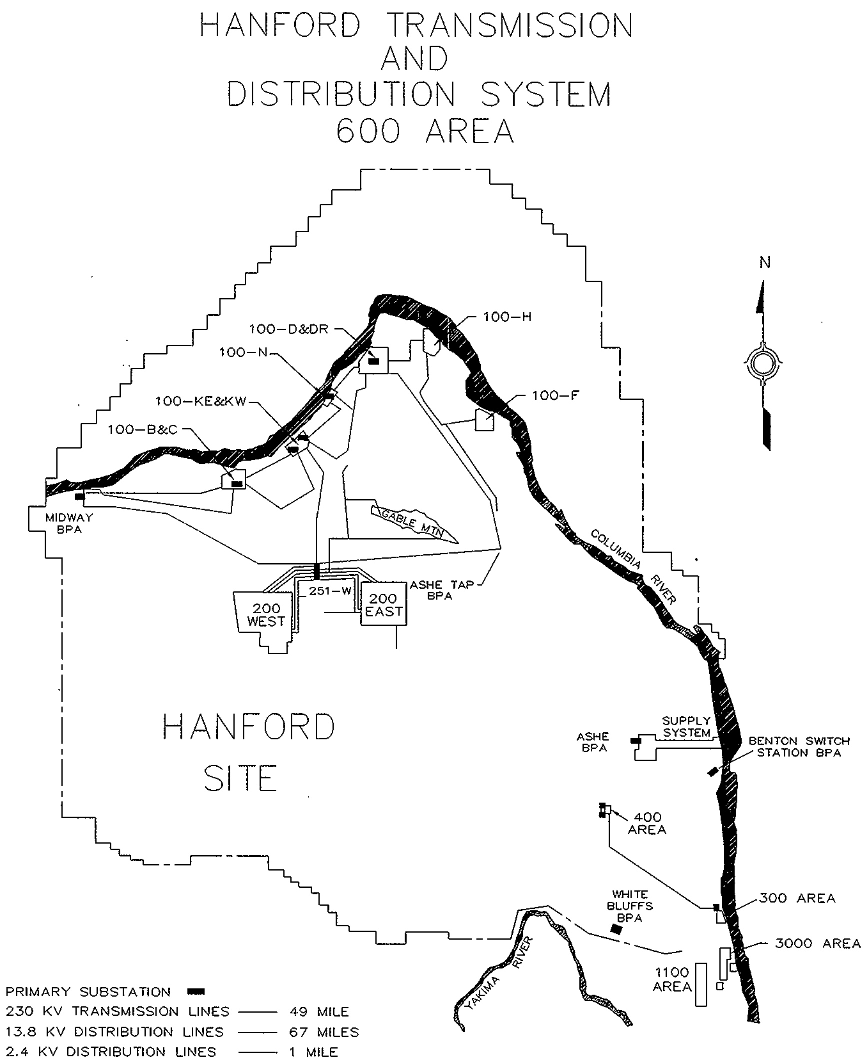
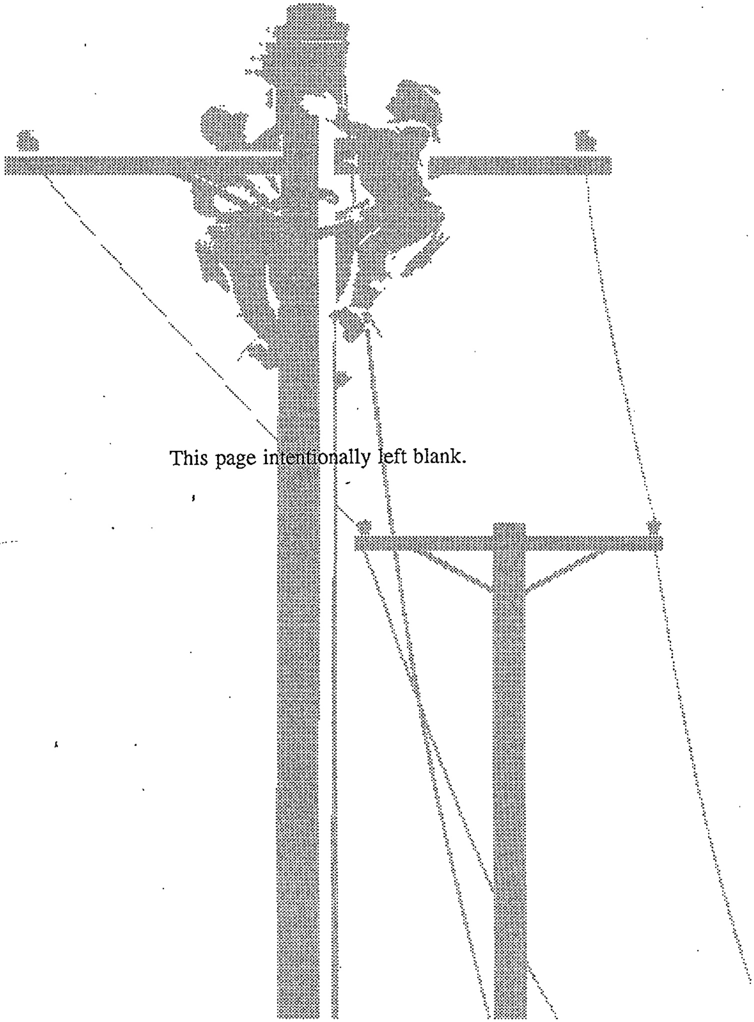


Fig. 5-1

RICHLAND



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5.2 100/200 Areas System.

5.2.1 Description. The 100/200 Area electrical transmission and distribution system is the electrical network that conveys electricity to facilities in what are referred to as the 100, 200, and 600 Areas of the Hanford Site. The transmission portion consists of high voltage (230 kV) lines in the 600 Area that convey purchased electricity from BPA delivery points to primary substations in the 100 and 600 Areas. Distribution refers to the electrical systems that convey power (13.8 kV and lower voltage) from primary substations to distribution transformers at designated facilities within the areas. Power to the 100/200 Areas electrical transmission and distribution system is provided from two sources: the BPA Midway substation at the northwest Hanford Site boundary, and a transmission line from the BPA Ashe Substation. The 100/200 Areas transmission and distribution systems, as with the BPA source lines, have alternate routings to assure electrical service to individual area and designated facilities within those areas. Approximately 50 miles of 230 kV transmission lines, six primary substations, and about 60 miles of 13.8 kV and 20 miles of 2.4 kV distribution lines derive the system.

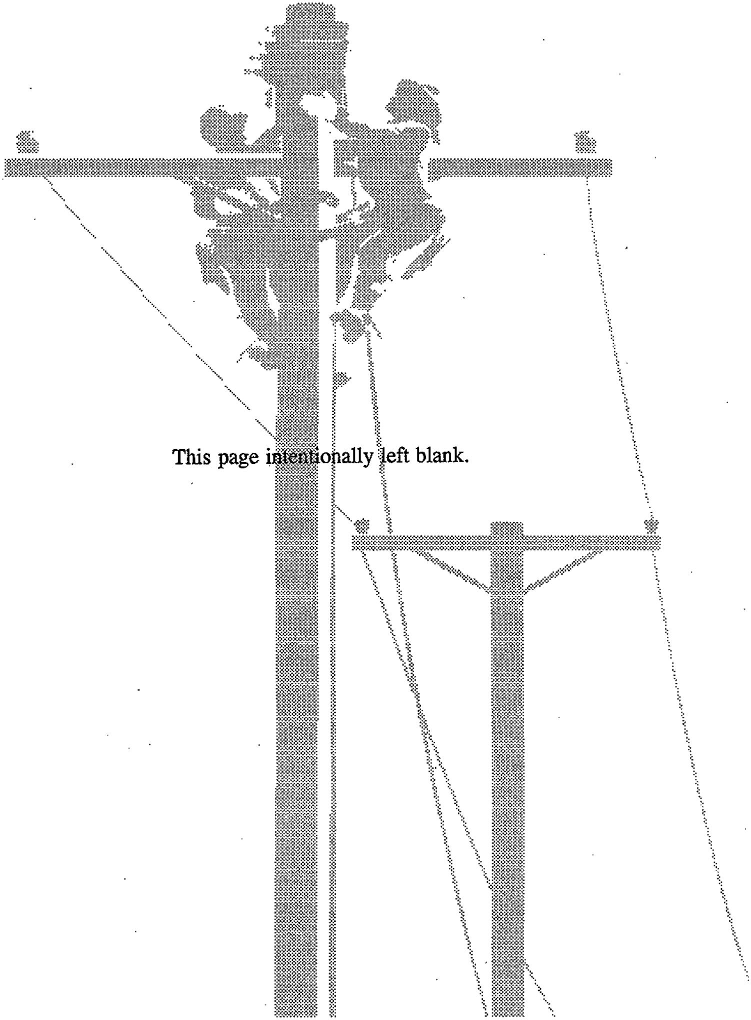
There is substantial excess substation capacity in the system to ensure continuity of highly reliable service. Each primary substation has at least twice the capacity of the peak demand to enable handling the entire load on a single transformer.

Due to the primary mission change from production to cleanup, the power requirements in the 100 Areas have been dramatically reduced. The large electrical demands of the old production reactors and auxiliary systems are gone. Early decommissioning activities sometimes abandoned electrical equipment in place. These items are being removed and disposed of properly. As the 100 Area facilities are dismantled, the associated electrical distribution systems will be eliminated. Despite a reduced load, the 100 Areas will require some electrical services throughout the cleanup effort. For example, electrical power will still need to be provided for raw water pump stations which supply water to active areas, offices, and spent nuclear fuel storage basins.

Figures 5-2 through 5-7 depict the general layout of the 100/200 Areas system.

5.2.2 Assessment of Condition. The 100/200 Area electrical transmission and distribution system is considered to be in very good condition. Given normal maintenance and routine replacements, the system should have a useful life of greater than 20 years.

5.2.3 Capacity. The six primary substations have a usable capacity of 195 MW. The system has a coincidental peak demand of 34.9 MW, thus leaving an available capacity of 154.2 MW. Based upon demand and consumption, the 200 Area transmission and distribution system, serving users in the 100 and 200 Areas, is approximately 65 percent of the electricity provided on-Site by the Electrical Utilities group. Table 5-1 provides a breakdown of the 100 and 200 Areas capacity.



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HANFORD TRANSMISSION AND DISTRIBUTION SYSTEM 100B

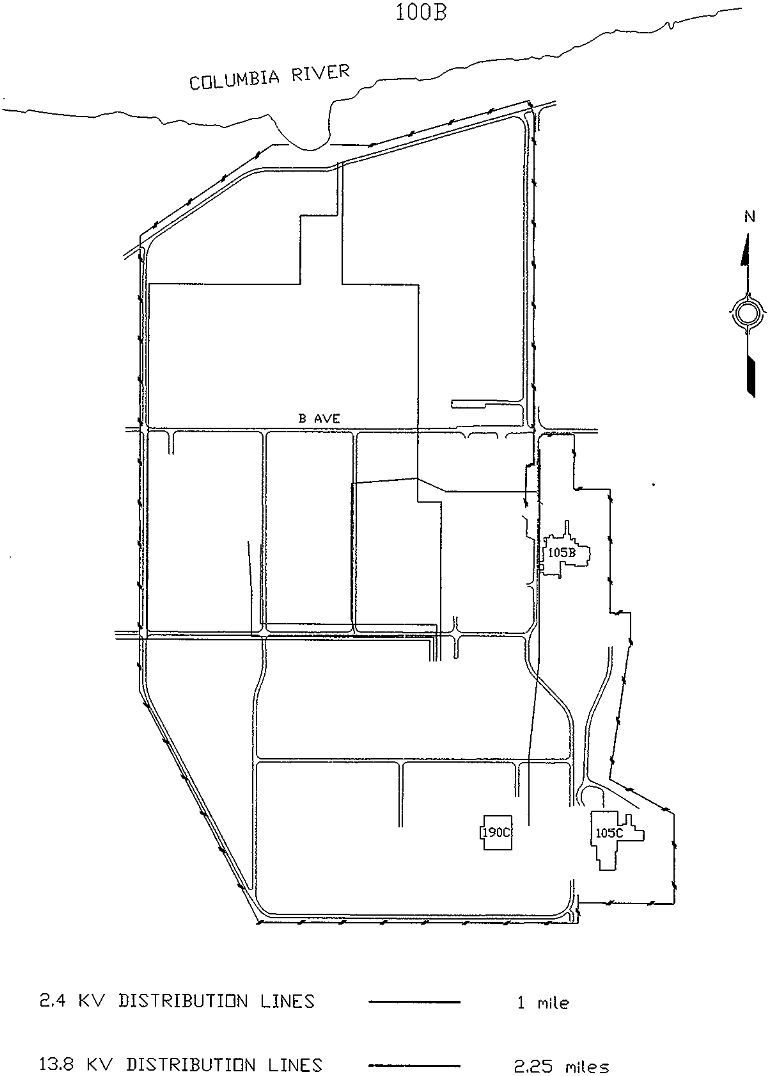
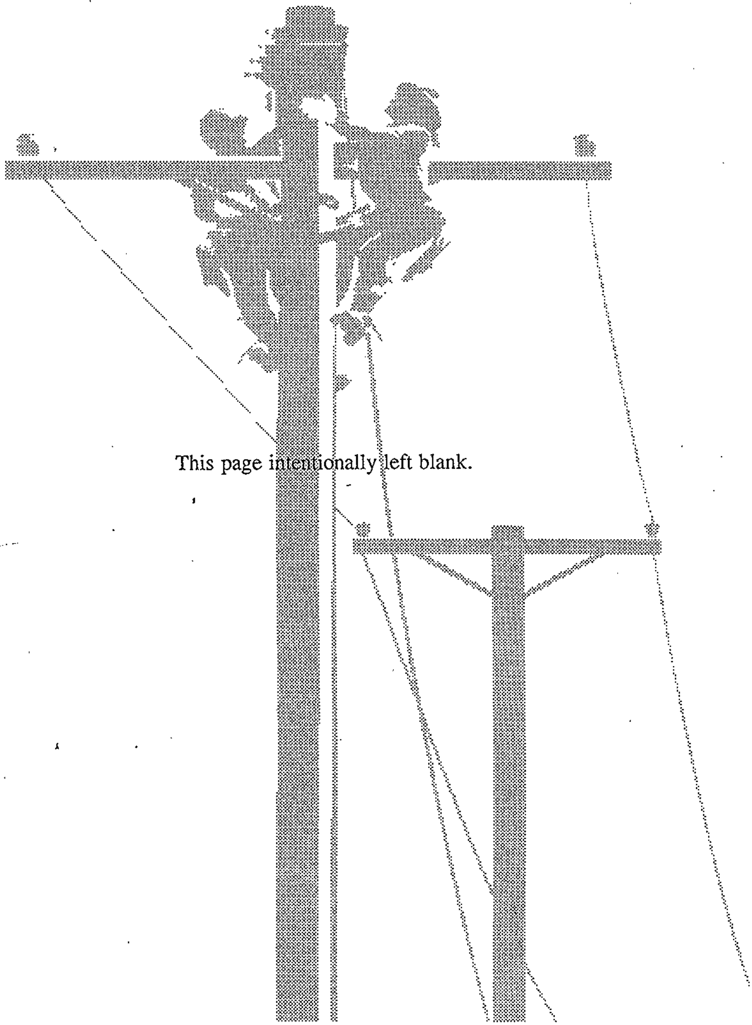


Fig. 5-2



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HANFORD TRANSMISSION
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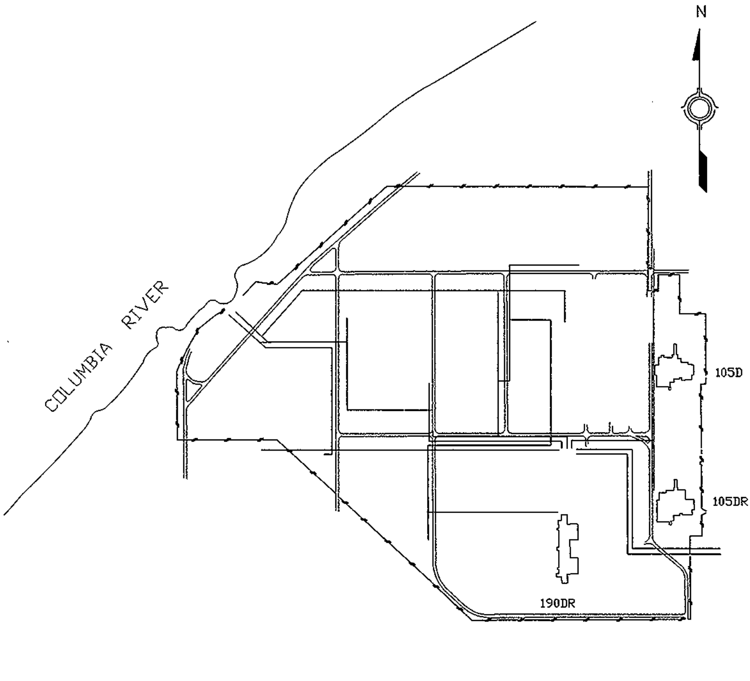
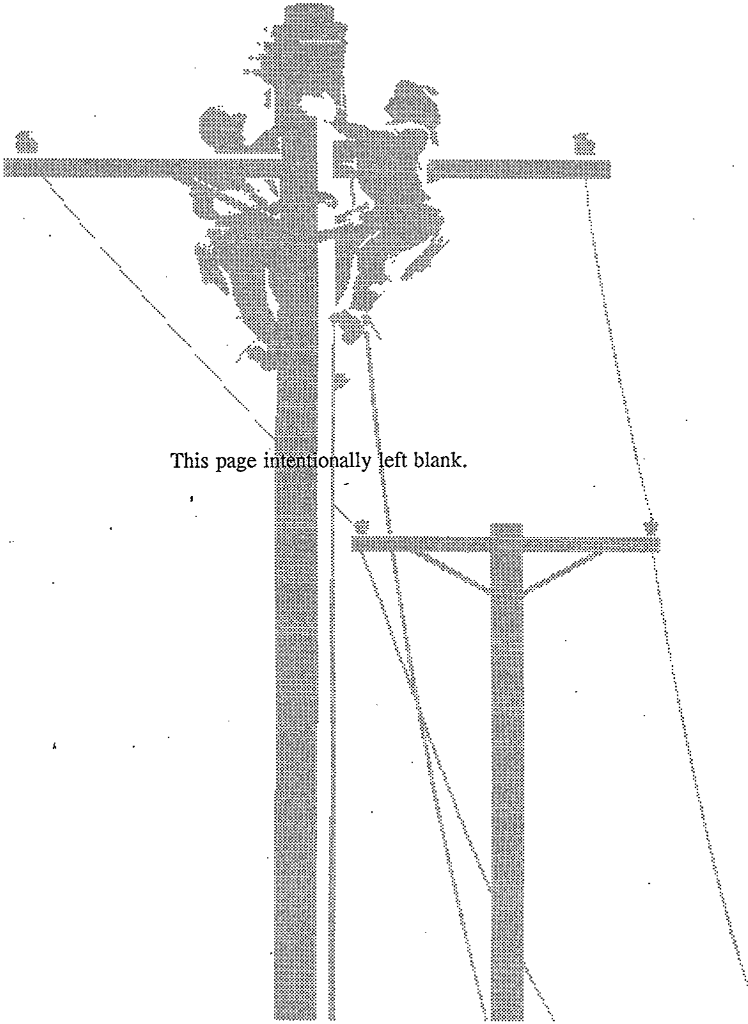
DISTRIBUTION SYSTEM
100D



2.4 KV DISTRIBUTION LINES 1 mile

13.8 KV DISTRIBUTION LINES 3.4 miles

Fig. 5-3



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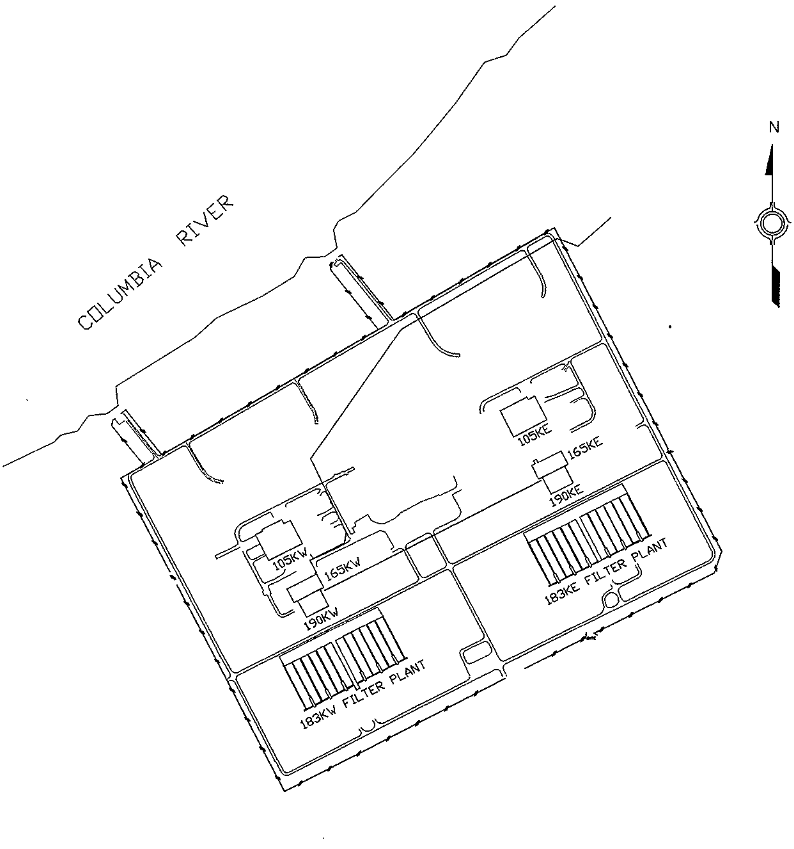
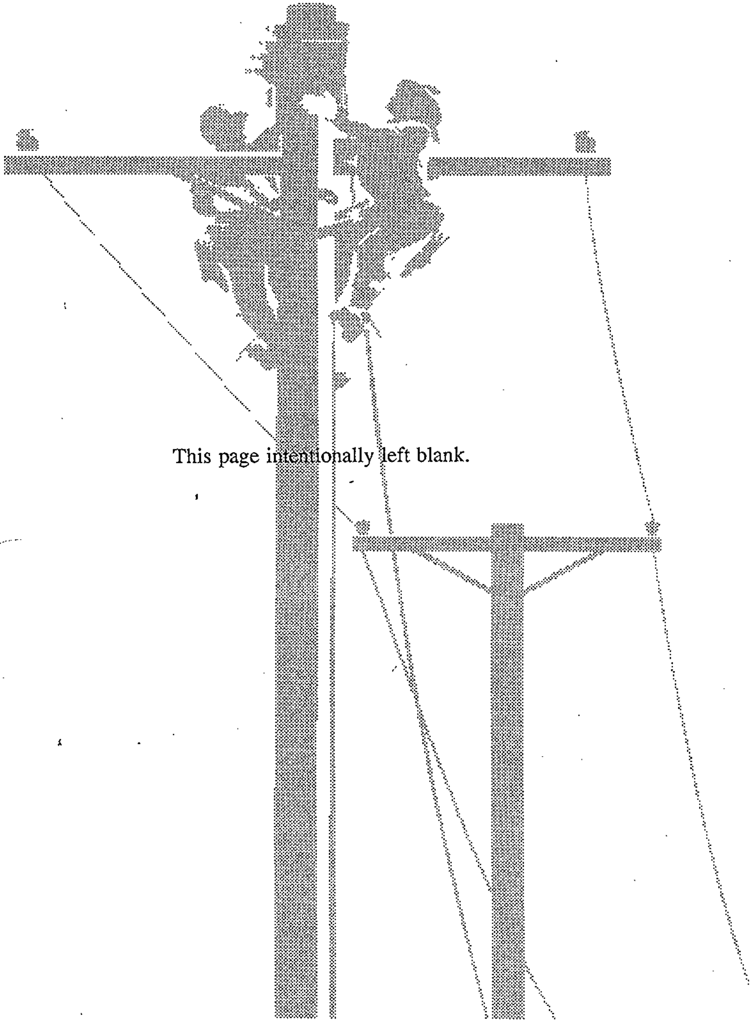
HANFORD TRANSMISSION
AND
DISTRIBUTION SYSTEM
100K



13.8 KV DISTRIBUTION LINES ——— 1 mile

Fig. 5-4



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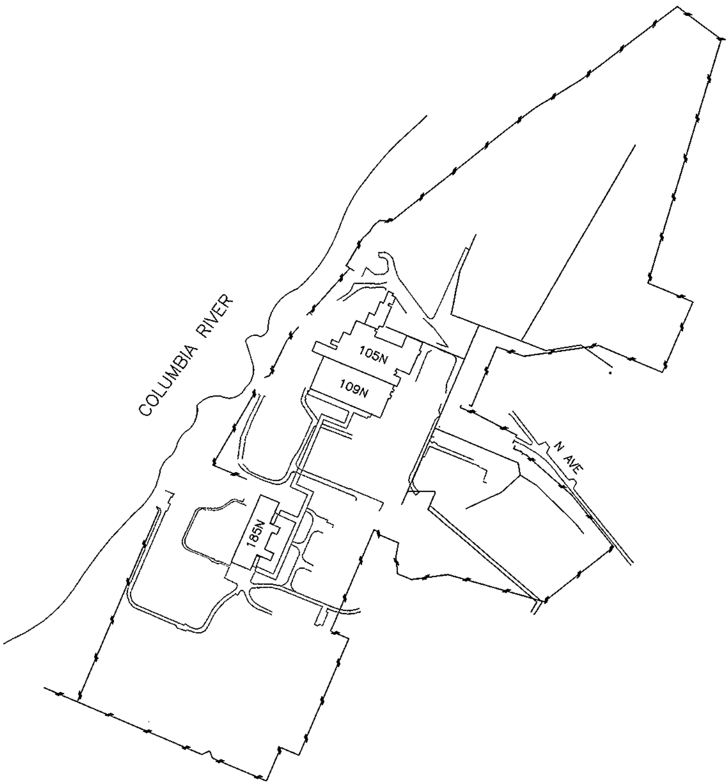
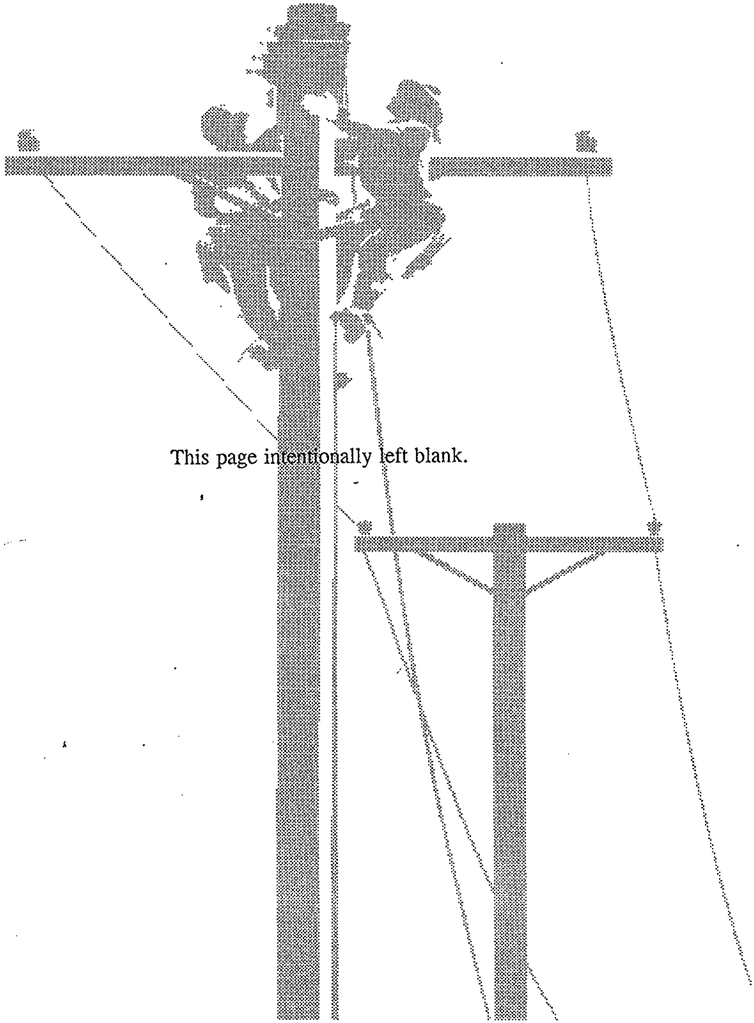
HANFORD TRANSMISSION
AND
DISTRIBUTION SYSTEM
100N



13.8 KV DISTRIBUTION LINES 1.5 miles

Fig. 5-5



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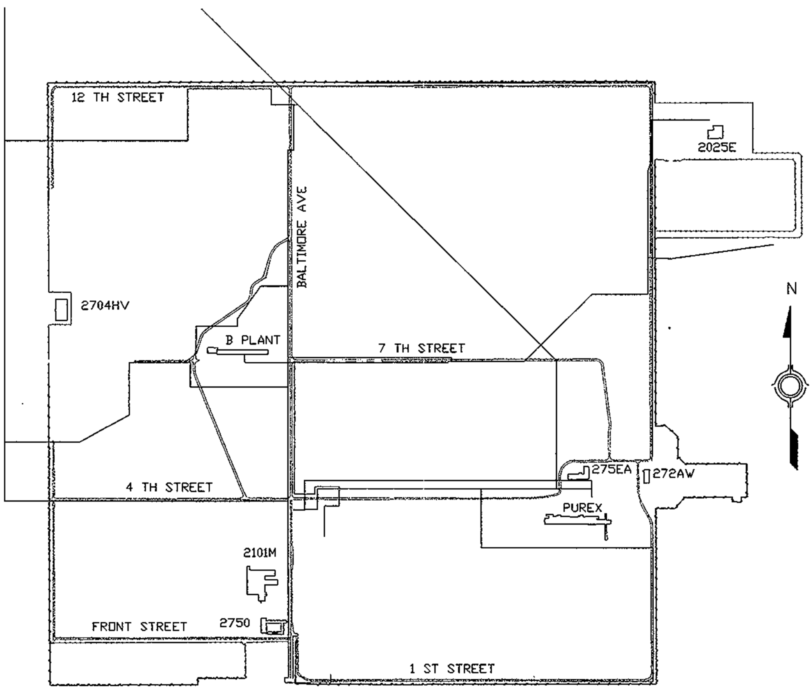
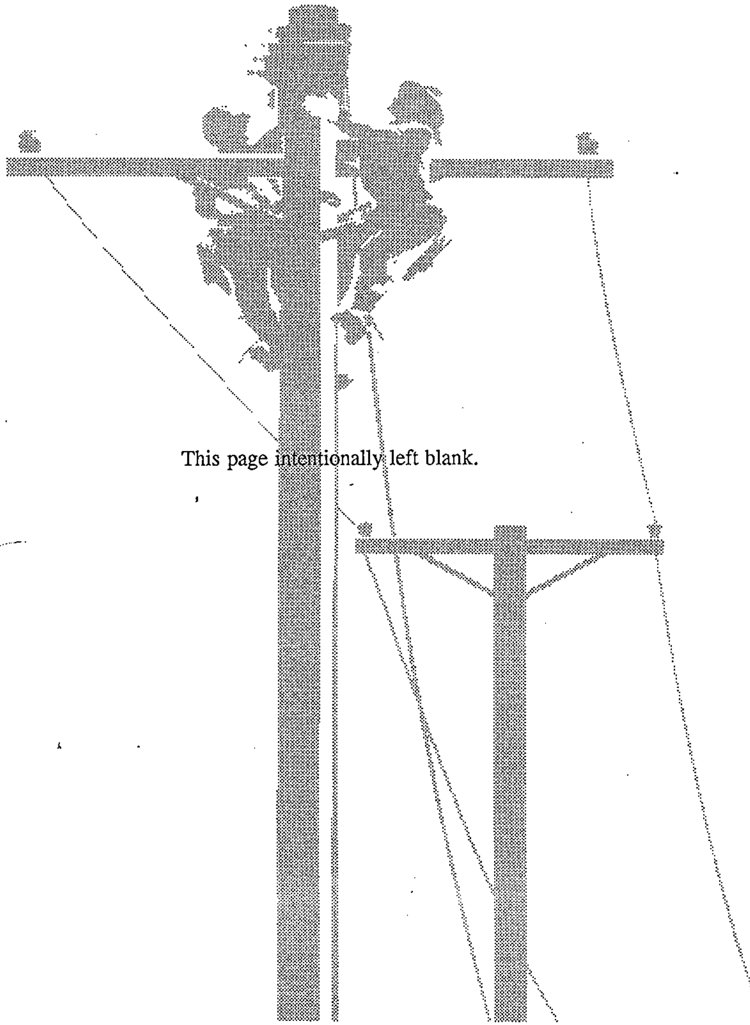
HANFORD TRANSMISSION
AND
DISTRIBUTION SYSTEM
200 EAST



2.4 KV DISTRIBUTION LINES —— 6 miles

13.8 KV DISTRIBUTION LINES —— 26 miles

Fig. 5-6



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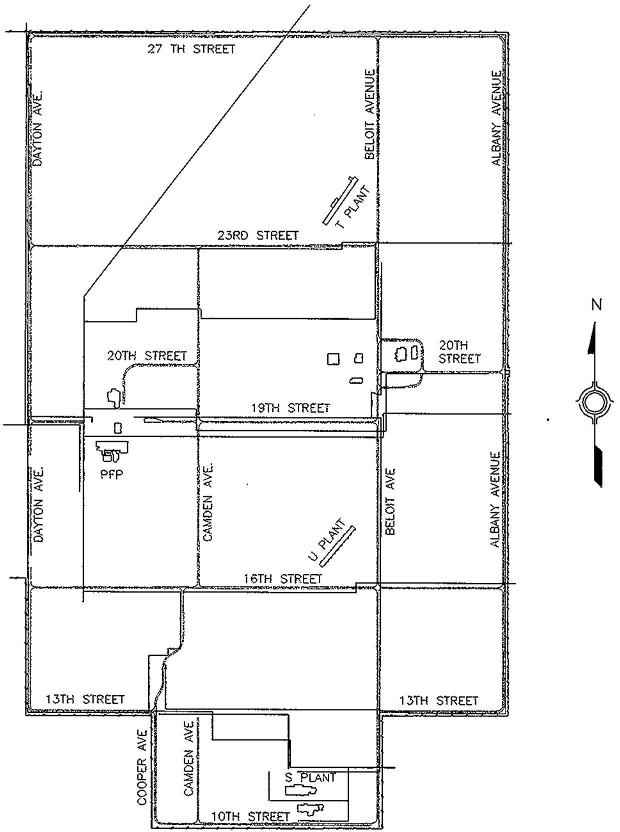
HANFORD TRANSMISSION
AND
DISTRIBUTION SYSTEM
200 WEST



2.4 KV DISTRIBUTION LINES ——— 11 miles

13.8 KV DISTRIBUTION LINES ——— 24 miles

Fig. 5-7

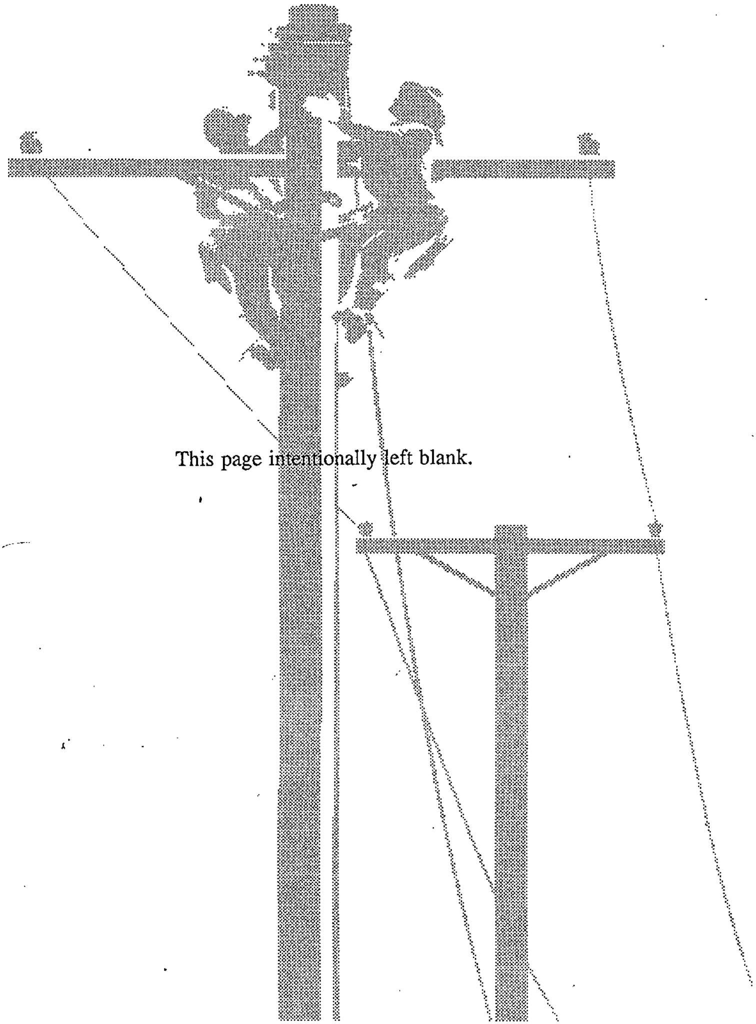


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TABLE 5-1

100/200 AREAS CAPACITY

Area	MVA Installed Capacity	MVA Usable Capacity	MW* Usable Capacity	MW Peak Demand	MW Available Capacity
100-B	62.5	31.25	25.0	2.8	22.2
100-D	31.25	31.25	25.0	4.2	20.8
100-KE	31.25	31.25	25.0	3.2	21.8
100-KW	100.0	50.0	40.0	3.7	36.3
100-N	50.0	50.0	40.0	0.0	40.0
200-E/W	100.0	50.0	40.0	26.9	13.1
Total	375.0	243.75	195.0	40.8	154.2
Coincidental Demand				34.9	

MVA = Megavolt Amps MW = Megawatts * = Usable capacity times average power factor of 0.8

System capabilities in the 200 Areas match present demand and expected growth over the next few years. As in the 100 Areas, the power demands have diminished somewhat as the nuclear fuel processing facilities move toward shutdown. This is a period of load transition, with several plants going into standby status while potentially tremendous additional loads are forecast as cleanup facilities are added. For example, the Department of Energy has committed to deliver up to 20 MW electrical power at 13.8 kV for each of the two TWRS privatization facilities at each contractor's parcel perimeter. As cleanup facilities are constructed the electrical distribution system will change to meet the new demand. Funding for these changes originates from each new facility's construction budget.

5.2.4 Value of System. The total cost of the 100/200 Areas electrical transmission and distribution system (including substation buildings and equipment) is approximately $48,200,000. This does not include buildings that house utility personnel, service vehicles and equipment, or spares inventory. The current replacement cost of the system is estimated at $63,009,653. The existing accounting system does not segregate annually reoccurring maintenance costs by service area. Area maintenance costs will become available through the new work management system to be implemented during FY 1998, and the data will be used in subsequent revisions of this model.

5.3 600 Area System

The 251-W substation, located in the 600 Area, serves as the Hanford Site electrical dispatch center and houses the SCADA System. The SCADA system monitors status and alarms, and provides remote control to allow the dispatcher to change electrical routings through seven primary (six in 100/200 Areas and one in 300 Area) and four secondary substations (one in 200-E, one in 200-W, and two in 300 Area). As requested by customers and programs, the 251-W substation is operated on a 24-hour (7 days-per-week) basis to maintain continuous electrical coverage of the Hanford Site. The SCADA system is over 20 years old, uses obsolete technology, and is currently being replaced with a new control system to allow for efficient load management, tracking, and trending. Switchgear buildings need to be maintained to continue safe operation. Approximately 49 miles of 230 kV transmission lines, and 67 miles of 13.8 kV, and 1 mile of 2.4 distribution lines are located within the 600 Area.

The total cost of the 600 Area electrical transmission and distribution system (including substation buildings and equipment) is approximately $11,920,883. The current replacement cost of the system is estimated at $23,687,425. The existing accounting system does not segregate annually reoccurring maintenance costs by service area. Area maintenance costs will become available through the new work management system to be implemented for FY 1998, and the data will be used in subsequent revisions of this model.

5.4 300 Area System

5.4.1 Description. The 300 Area electrical distribution system functions as the electrical distribution network for facilities located in the 300 Area on the Hanford Site. Electrical power is provided by two separate, BPA-owned 115 kV transmission lines: one from the BPA Benton substation and the other from the BPA White Bluffs substation. These alternate source lines reduce the possibility of a complete power outage in the area and also allow for rerouting power during maintenance outages.

The primary system consists of one primary substation containing three 115 kV to 13.8 kV step down transformers providing normal power. The secondary distribution system includes two substations, approximately 3.7 miles of 13.8 kV aerial distribution lines, an estimated 15 miles of 13.8 kV lines in underground raceways, and 0.2 miles of 2.4 kV distribution lines.[12] Seven primary lines feed the 300 and 600 Area facilities and one line extends as a backup to the FFTF to provide power for maintenance outages. Two main switching stations allow power to be provided from

[12]Standby power to designated facilities is delivered via the 2.4 kV distribution system. The system has five diesel generators capable of providing backup power in the event of an outage of the 13.8 kV distribution system.

alternate feeds to provide for quick restoration of service in the event of outages and for planned maintenance without interruption of service to facilities.

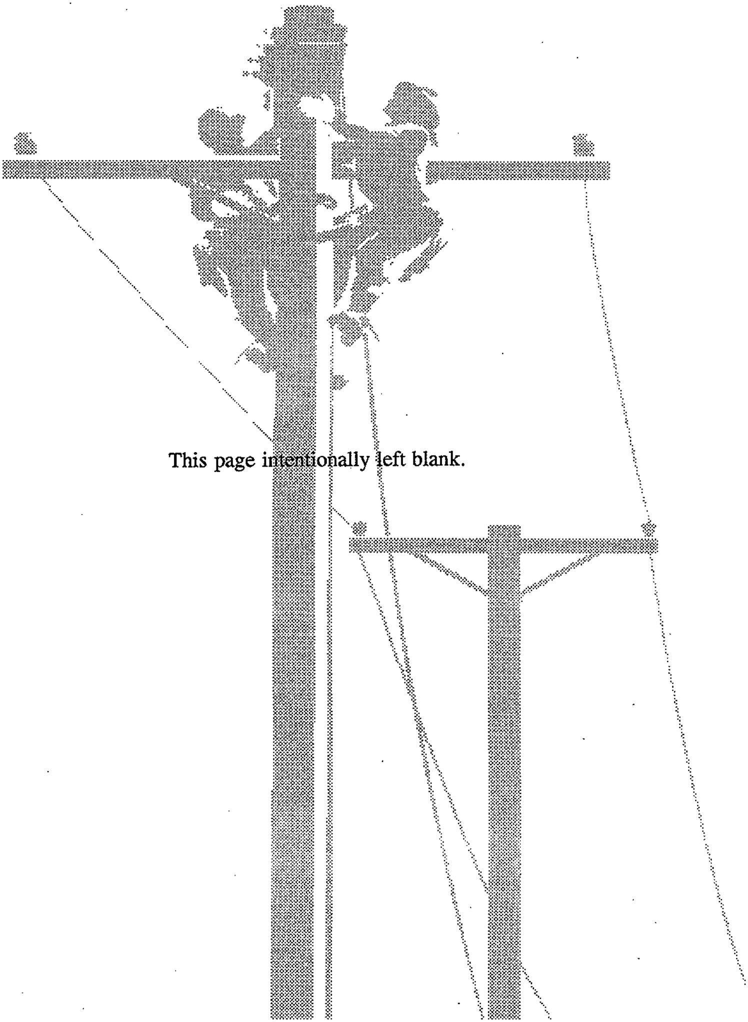
Over 50 secondary switching stations (distribution transformers individually sized according to the loads being serviced) support a total capacity of over 70,000 kVA. Alternate routings, where required, meet nuclear safety guidelines or where a high reliability for long-term experiments is needed.

Two major upgrade projects for the 300 Area electrical distribution system were completed in FY 1995. These projects, valued at $22 million, enhanced personnel safety and brought the system into compliance with the National Electrical Safety Code. The 2.4 kV normal power lines and transformers were eliminated. Only the standby 2.4 kV power lines and generators remain active. Projects included the conversion of a dual voltage distribution system to a single voltage system (13.8 kV), relocating power cables underground, replacing obsolete fence and street lighting, downsizing transformers, and creating a duct bank system for future cable relocation. Exceptions to the upgrades are the 300 Area main (B3-S4) and 352-E (C3-3) substations 13.8 kV switchgear which are expected to require replacement in approximately eight years. The costs of these two switch systems has been estimated at $2.6 million. Work on these two capital projects is assumed to be started and completed during FY 2005.

Figure 5-8 depicts the general layout of the 300 Area system.

5.4.2 Assessment of Condition. The 300 Area electrical distribution system is considered to be in very good condition, and has been rated as "good to excellent for installations of this type" by DOE-HQ consultants. Given normal maintenance and routine replacements, the system should have a useful life of greater than 20 years. The main substation for the 300 Area has radioactive contamination beneath it. Although the contamination is stable, it will present difficulty if and when excavation is required.

5.4.3 Capacity. The 300 Area electrical system has two 20 megavolt-ampere (MVA) transformers and one 7.5 MVA transformer for a usable capacity of 22.0 MW. The system has a coincidental peak demand of 13.8 MW, thus leaving an available capacity of 8.2 MW. Based upon demand and consumption, the 300 Area transmission and distribution system, serving users in the 300 and 600 Areas, provides approximately 35 percent of the electricity provided on-Site by the Electrical Utilities group. Table 5-2 provides a breakdown of the 300 Area capacity.



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HANFORD TRANSMISSION
AND
DISTRIBUTION SYSTEM
300 AREA

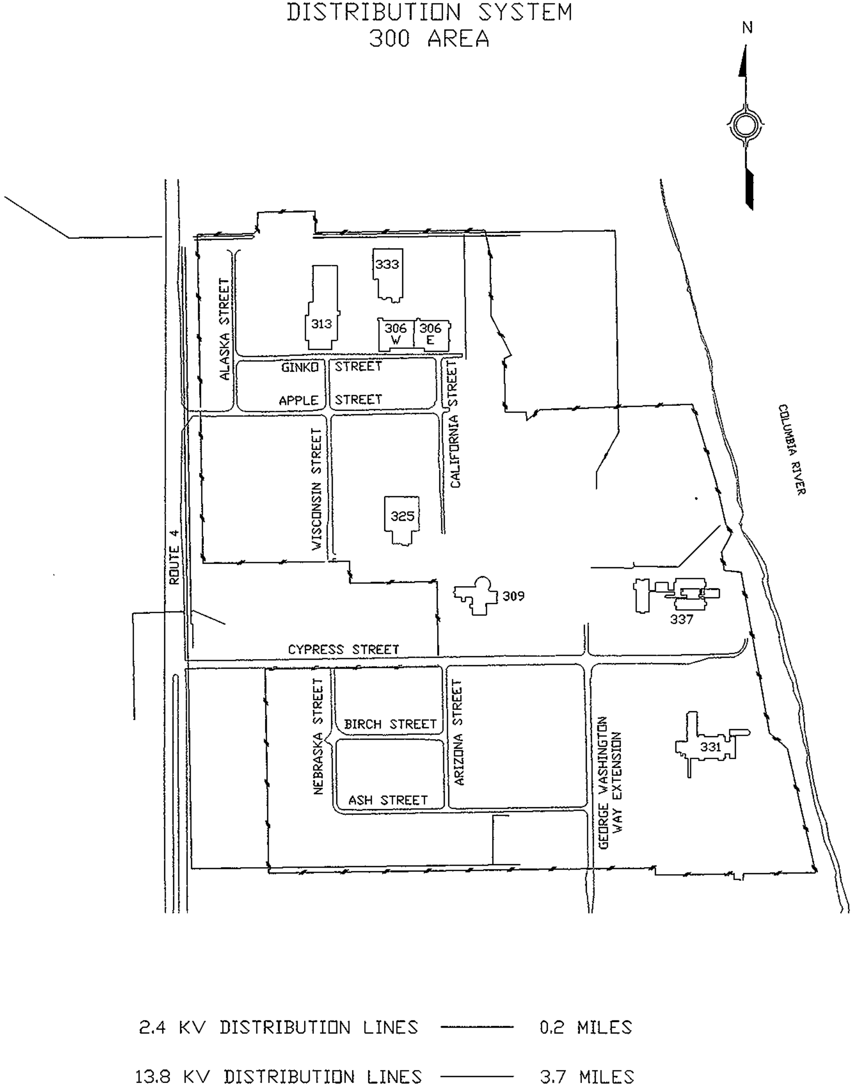

Fig. 5-8

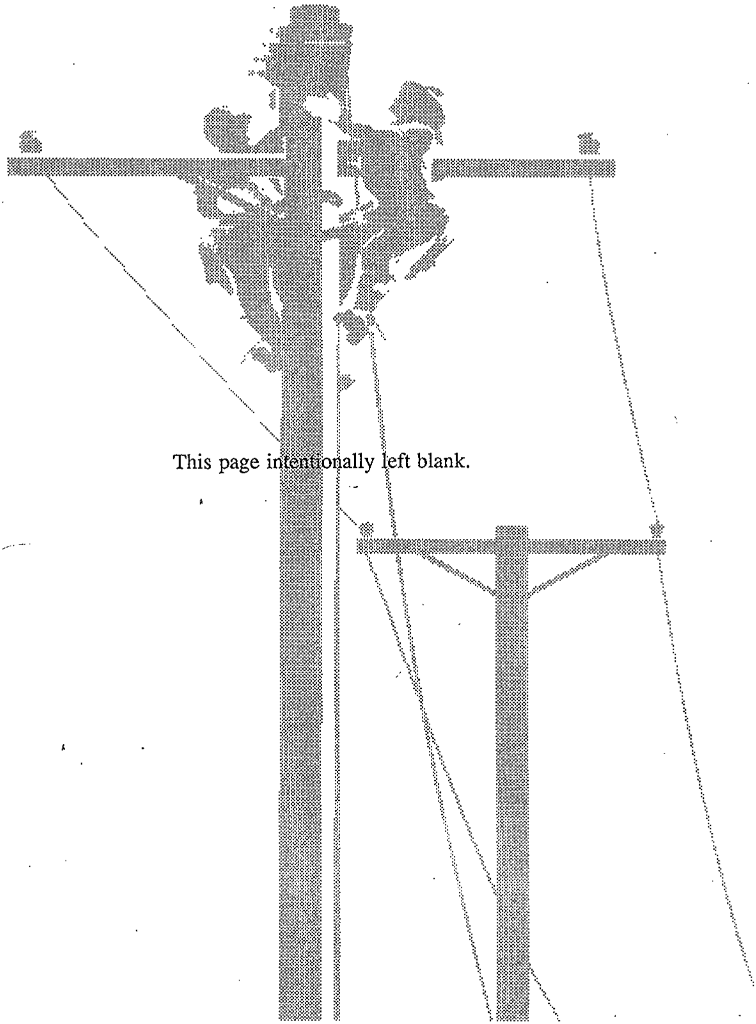

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TABLE 5-2

300 AREA CAPACITY

Transformer	MVA Installed Capacity	MVA Usable Capacity	MW* Usable Capacity	MW Peak Demand	MW Available Capacity
1 each, 115 kV to 13.8 kv	7.5	7.5	6.0	0.0	6.0
2 each, 115 kV to 13.8 kV	40.0	20.0	16.0	13.8	2.2
Total	47.5	27.5	22.0	13.8	8.2

MVA = Megavolt Amps MW = Megawatts * = Usable capacity times average power factor of 0.8

5.4.4 Capabilities. Approximately 90 percent of the 300 Area load is currently metered. Roughly 75 percent of the load is read automatically using FDAS. Currently, only kW hours actually consumed are metered. Power factor metering is not required due to power factor correction being performed via line capacitors.

5.4.5 Value of System. The total cost of the 300 Area electrical system is approximately $13,248,272. The current replacement cost of the system is estimated at $21,811,320. The existing accounting system does not segregate annually reoccurring maintenance costs by service area. Area maintenance costs will become available through the new work management system to be implemented during FY 1998, and the data will be used in subsequent revisions of this model.

5.5 400 Area

5.5.1 Description. Primary electrical power to the 400 Area is provided by two 115 kV BPA transmission lines: one from the BPA Benton substation; and the second from the BPA White Bluffs substation. One 13.8 kV tie line from the 300 Area to the 400 Area power system provides alternate power for maintenance outages, and a 3 MW gas turbine generator is also available for emergency power. The distribution lines in the 400 Area electrical system are redundant to designated facilities to ensure continuity of service and rerouting of power for maintenance of system components.

The FFTF facility is currently maintained in a standby capacity until DOE determines whether or not the facility has a role in the nation's tritium production strategy. A decision is expected by December 1998, or earlier. Should FFTF be rejected, the emergency turbine generator will be taken out of service as soon as the sodium is drained from the reactor vessel.

5.5.2 Assessment of condition. The electrical systems in the 400 Area are relatively new. They were installed in 1980 through 1985 as part of the FFTF and Fuels and

Materials Examination Facility (FMEF) construction projects. Considering the age of the systems and components, it is assumed that with proper maintenance the system will have a useful life of at least another 20 years. The uncertainty of future activity in the existing 400 Area facilities limits the options for the electrical transmission and distribution system.

5.5.3 Capacity. The 400 Area contains two substations: 451-A, which serves the FFTF Reactor and associated buildings; and 451-B, which serves the FMEF and associated buildings. See Table 5-3.

Recent upgrade projects have matched newly installed transformers to meet actual load requirements. There are, however, additional large transformers that support very small loads and therefore result in excessive energization losses. The appropriate timing needs to be determined for downsizing electrical systems as deactivation of the facilities and areas progress.

5.5.4 Value of system. The total cost of the 400 Area electrical transmission and distribution system (including substation buildings and equipment) is approximately $21,547,800. The current replacement cost of the system is estimated at $30,608,634.

5.5.5 Maintenance costs. The Electrical Utilities group performs maintenance for the 400 Area on a work order basis. Three work orders accumulated $20,675 in costs and 563.4 hours (0.44 FTE) through June 15, 1997.

TABLE 5-3

400 AREA CAPACITY

Substation	MVA Installed Capacity	MVA Usable Capacity	MW* Usable Capacity	MW Peak Demand	MW Available Capacity
451-A	50.0	Generators	40.0	8.0	32.0
451-B	66.6	33.3	26.6	4.1	22.5
Total	116.6	33.3	66.6	12.1	54.5
Coincidental Demand				12.0	

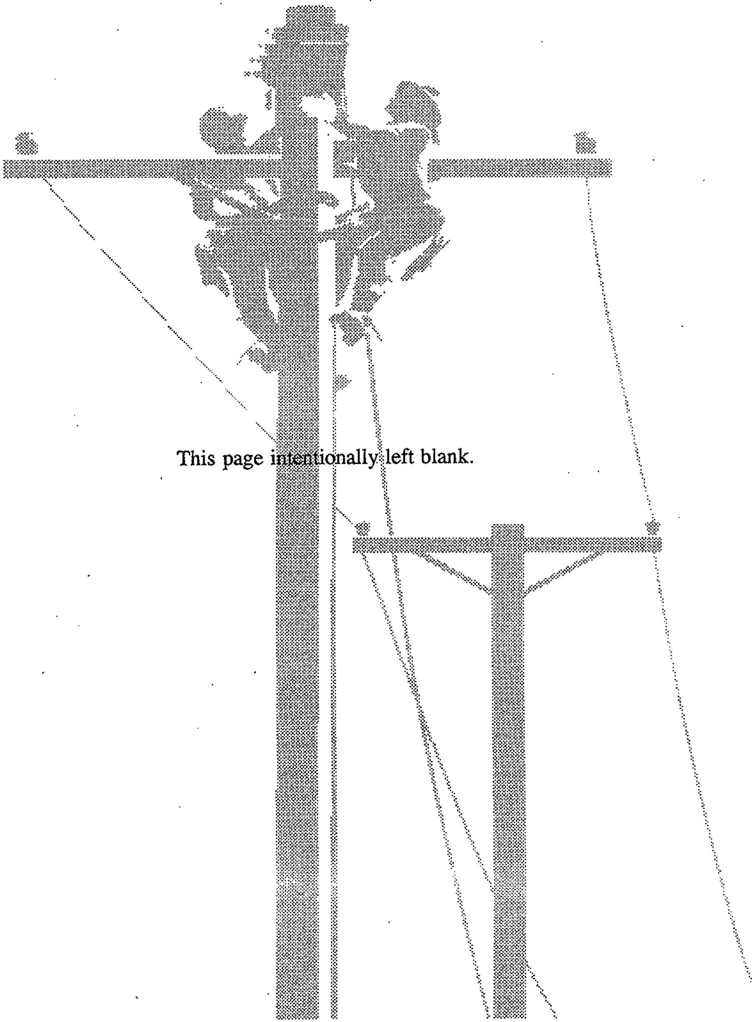
MVA = Megavolt Amps MW = Megawatts * = Usable capacity times average power factor of 0.8

5.6 Customer Expectations and Requirements

In some service-oriented businesses, occasional busy signals, missed schedules, and cancellations are acceptable and tolerable. Power interruptions are not. Electrical Utilities is--and must continue to be--held to a much higher standard of service and reliability. The service provided by Electrical Utilities is an essential ingredient in the success of the Hanford mission. Customers expect accurate billing, low rates, load forecasting, core technical strengths, and excellent customer service. In addition, many customers want service elements beyond those which a utility routinely provides, such as outage coordination, 24-hour dispatch, and customer support services. Electrical Utilities personnel have the capability to provide these services, which are directly funded by the facilities.

The Hanford Site electrical transmission and distribution system, designed and constructed to provide an enhanced level of reliability, is essential to Site customers and their ability to conduct Hanford mission specific activities. Based on criteria set by DOE Order 6430.1A, Electrical Utilities maintains a distribution system configuration which provides alternate primary supplies for specified critical facilities.

The methodology used by Electrical Utilities management when determining a reasonable level of service was a combination of regulatory drivers and all available information. In their absence, "good business practice" and a "cost effective use of the taxpayers' dollars" were applied.



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6.0 ELECTRICAL DISTRIBUTION CAPACITY AND FORECAST MODEL

6.1 Introduction

The FY 1996 kWh consumption was used as the base year for capacity requirements. Existing documentation was used to develop a spreadsheet model forecasting an anticipated level of activity and capacity required for the next ten years. Past experience has caused Electrical Utilities management to have varying levels of confidence with the various data sources used to develop this model. As a result, risks, assumptions, constraints, and an average confidence level of medium (probability of success) were factored into the model. Table 6-1 lists the various data sources and confidence levels used.

TABLE 6-1

ELECTRICAL DISTRIBUTION CAPACITY DATA SOURCE CONFIDENCE LEVEL

Data Source	Confidence Level
Customer work order requests	Medium at start of year, high by mid-year
Hanford Site Summary Schedule	High for facility closure schedule and program completion, and identification of new work
Site Support Program Plan/Multi-Year Program Plan	Medium
Twenty-Year Power Forecast	Medium as new project loads are generally not known.
Inquiries and anticipated need dates by program customers for new facility loads and removal of existing loads	Medium
Average confidence factor	Medium

All charts in this section model three cases (low, medium, and high--relate to confidence level) for demand.[13] The total is simply a non-coincidental summation by area. The coincidental demand factors applied to each area are: 0.85 for the 100/200 Areas, 0.90 for the 300 Area, and 0.95 for the 400 Area. The forecasted demand is for BPA electricity only (which constitutes 97 percent of the total load) and does not include the City of Richland or services from other utilities.

[13]Since the charts for both demand and consumption are quite similar, only the demand charts have been included for simplicity.

6.2 Total Site

Electrical needs are expected to gradually decrease over the next five years due to decontamination and decommissioning activities, despite new loads from clean up activities. A significant increase is anticipated during the remainder of this ten year forecast period, primarily from Phases I and II of the TWRS privatization plants in the 200 Areas, and potential restart of FFTF in the 400 Area.

In summary, the 10 year power forecast shows an overall increase due to the primary mission change from production to cleanup and validates a continuing need to assure the reliable, safe and cost effective supply of electrical services to customers. See Fig. 6-1.

FY 1996-2007 TOTAL SITE ELECTRICAL POWER FORECAST

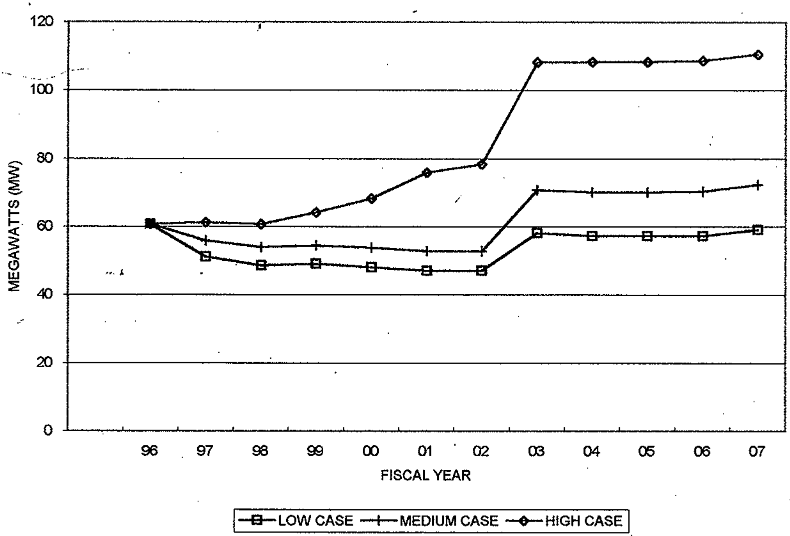


Fig. 6-1

6.3 100/200 Areas

The 100/200 Areas electrical system 10 year power forecast shows an overall increase due to the primary mission change from production to shutdown and cleanup. While the power requirements in the 100 Areas are reduced, substantial increases due to clean-up activities are anticipated in the 200 Areas, with TWRS Phase I and II the primary users. Capacity increases that are required for major new electrical loads are provided by the program/project that generates the need. See Fig. 6-2.

FY 1996-2007 100/200 AREAS ELECTRICAL POWER FORECAST

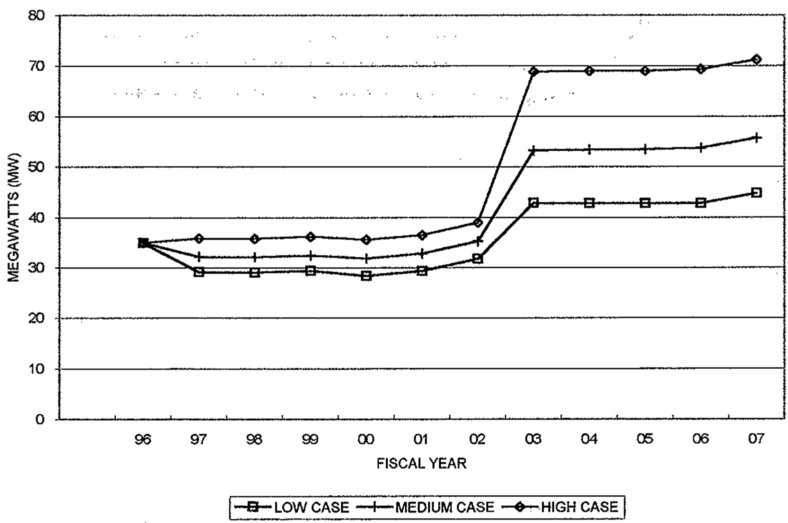


Fig. 6-2

6.4 300 Area

The 300 Area electrical consumption is forecasted to remain fairly constant over the next 10 years. This forecast is for services currently fed from the existing 300 Area distribution system. It does not take into consideration demand from the EMSL or HAMMER facilities, which are supplied by the City of Richland. Increases driven in part by the expected conversion from steam heat to electric heat in some facilities are offset by decontamination and decommissioning activities. Although some buildings are scheduled to be deactivated, economic transition activities may keep the electrical demand and consumption at or near the present level. The 300 Area load is dwarfed in comparison to the loads anticipated in the 200 Areas. See Fig. 6-3.

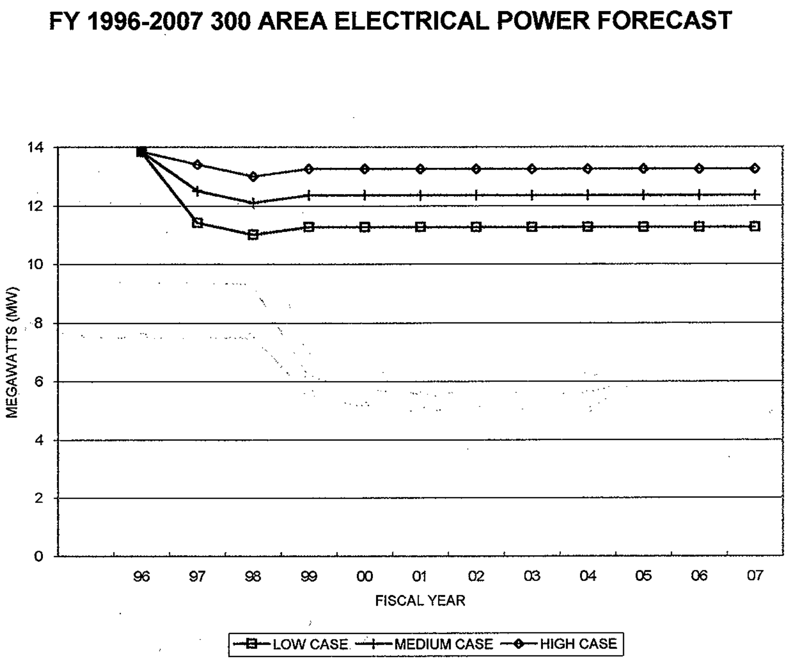


Fig. 6-3

6.5 400 Area

The current standby operations of the 400 Area electrical system is a joint activity of FFTF Operations and FFTF Engineering with support provided by the Electrical Utilities organization. This arrangement is expected to continue until December 1998 when DOE determines whether or not the facility has a role in the nation's tritium production strategy. Pending DOE's decision, the 400 Area forecast will show a decline in power needs as the facilities transition to shutdown and sodium removal, or an increase as systems are re-energized. The forecast is only for BPA power and does not include power for the Laser Interferometer Gravitational Wave Observatory (LIGO) where it is assumed that the Benton County Public Utility District will supply power via the 451-B substation. See Fig. 6-4.

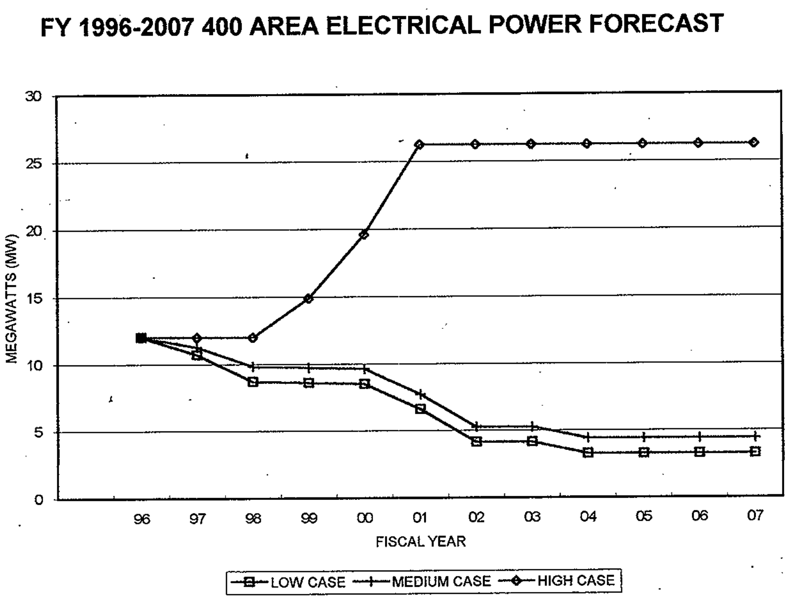
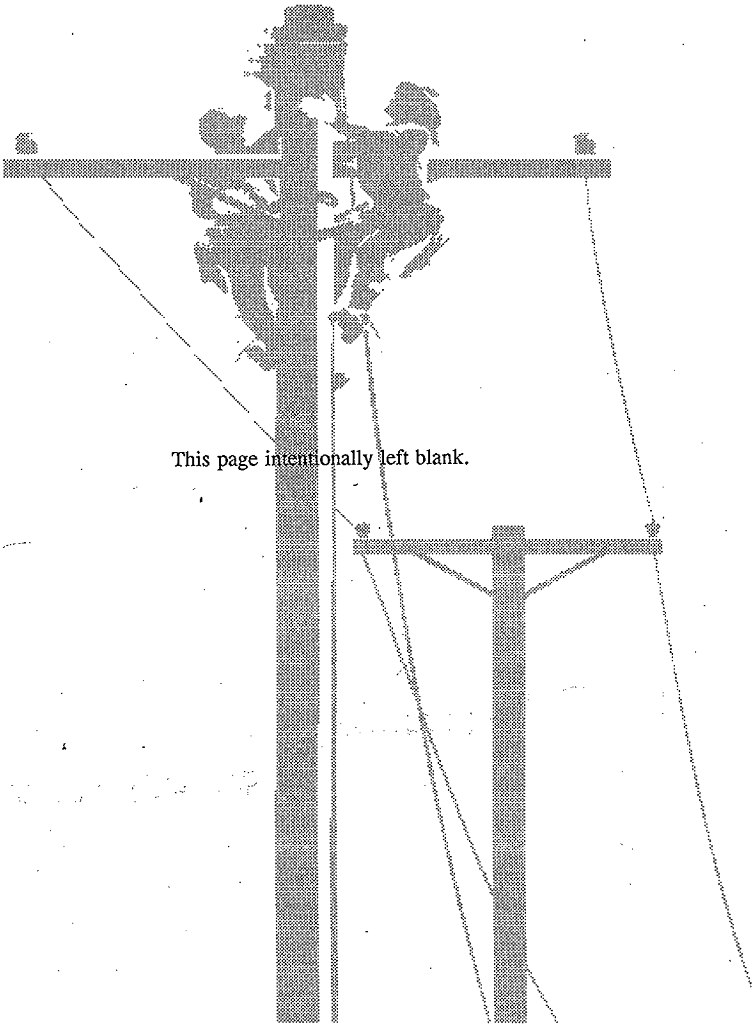


Fig. 6-4



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7.0 FUNDING AND RESOURCE PROJECTION MODEL

7.1 Introduction

The FY 1997 budget[14] was used as the base year for funding and resource requirements. Historical experience, and estimates and observations of variables discussed in previous sections of this document were used develop a spreadsheet model forecasting an anticipated level of activity and resources required for the next ten years.

Past experience has caused Electrical Utilities management to have varying levels of confidence with the various data sources used to develop this model. As a result, risks, assumptions, constraints, and an average confidence level of medium (probability of success) were factored into the model. Table 7-1 lists the confidence level of the various data sources used.

TABLE 7-1

FUNDING AND RESOURCE DATA SOURCE CONFIDENCE LEVEL

Data Source	Confidence Level
Customer work order requests	Medium at start of year, high by mid-year
Cost Account Plan	High for indirect labor and overhead
Hanford Site Summary Schedule	High for facility closure schedule and program completion, and identification of new work
Site Support Program Plan/Multi-Year Program Plan	Medium
Electrical Utilities Forecast	Medium
Requests by program customers for new facility loads and removal of existing loads	Medium
Average confidence factor	Medium

The Electrical Utilities forecast includes:

- past work practices

[14]The FY 1997 Electrical Utilities budget reflects implementation of aggressive re-engineering activities which significantly reduced staffing and costs.

- potential deactivation of substations (with a corresponding decrease in backlog maintenance and infrastructure)

- potential elimination of redundant systems as hazardous and radioactive facilities and contaminated areas are decontaminated and decommissioned

- reducing other infrastructure where no need exists

- continuing to move towards best commercial practices where allowed by DOE requirements and company policies

7.2 Staffing Forecasts and Funding Requirements

An experienced staff is the single most important factor in maintaining reliability. Regrettably, expenses may also be controlled with reduced staffing levels. However, if Electrical Utilities is forced to make deep staffing cuts, the ability to supply reliable power to customers will be jeopardized. Currently, Electrical Utilities is composed of 13.8 FTE bargaining unit, 18.3 FTE exempt, and 3.0 FTE nonexempt personnel, or a total of 35.1 FTE.[15] An additional 10.3 FTE are direct funded. No additional FTE are required to meet the demands of the projected work scope over the next ten years. See Table 7-2.

7.2.1 FY 1998. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- economic transition needs

- eight FY 1998 Landlord Program Site Infrastructure projects within the current target funding level

- Project W-503, TWRS Phase I Privatization Facilities

- completion and initial start-up of Canister Storage Building complex

- fuel removal from K Basins and cold vacuum drying systems

- 300 Area Facilities and Site Services Phase 3

- liquid effluent facility enhancement construction

- typical Electrical Utilities operations and maintenance activities

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[15]Full time equivalent figures which include 1.3 FTE exempt and 0.7 FTE bargaining unit Support from Others.

TABLE 7-2
FY 1997-FY 2007 BUDGET/STAFFING FORECAST

FTE Detail	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
Electrical Utilities											
Exempt	17.0	17.0	16.7	16.4	16.4	16.4	16.6	16.6	16.6	16.6	16.6
Non-Exempt	3.0	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
Bargaining Unit	13.1	13.2	11.6	10.1	9.8	9.8	10.6	10.6	10.6	10.6	10.6
Total	33.1	33.2	31.3	29.4	29.1	29.1	30.1	30.1	30.1	30.1	30.1
Support from Others											
Exempt	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Non-Exempt	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Bargaining Unit	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Total FTE Levels	35.1	35.2	33.3	31.4	31.1	31.1	32.1	32.1	32.1	32.1	32.1

Cost Element Table	FY 1997	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
0 Labor	2,405.8	2,502.2	2,398.3	2,377.9	2,414.1	2,478.7	2,627.2	2,698.6	2,772.2	2,848.1	2,924.0
1 Materials	213.3	213.3	213.3	193.0	193.0	193.0	213.3	213.3	213.3	213.3	213.3
2 Purchased Services	282.7	118.6	118.6	107.3	107.3	107.3	118.6	118.6	118.6	118.6	118.6
3 Other Hanford Contractors	42.0	42.0	42.0	38.0	38.0	38.0	42.0	42.0	42.0	42.0	42.0
7x Fee/Non DOH		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8 Revenue (wheeling credits)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9 Enterprise Companies	306.2	357.2	357.2	323.3	323.3	323.3	357.2	357.2	357.2	357.2	357.2
Subtotal Net Budget	3,250.0	3,233.3	3,129.4	3,039.5	3,075.7	3,140.4	3,358.4	3,429.7	3,503.3	3,579.2	3,655.2
4 Site Services	573.1	605.8	605.8	548.2	548.2	548.2	605.8	605.8	605.8	605.8	605.8
5 Internal Charges	815.2	809.1	809.1	732.2	732.2	732.2	809.1	809.1	809.1	809.1	809.1
6 LMSI Support	150.8	117.0	117.0	105.9	105.9	105.9	117.0	117.0	117.0	117.0	117.0
7C DOH	196.2	291.1	291.1	263.4	263.4	263.4	291.1	291.1	291.1	291.1	291.1
Total Baseline	4,985.3	5,056.3	4,952.4	4,689.4	4,725.6	4,790.2	5,181.5	5,252.8	5,326.4	5,402.4	5,478.3

Notes:
1. This table is a proposed forecast only and should not be construed as a proposed budget for any given fiscal year.
2. Annual hours per FTE not available for FY 1999-FY2007 forecasts. Use of 1818 hours per year per FTE is a fairly consistent number and acceptable by budget analysts for estimating purposes.
3. Escalation rates as follows: FY99 1.027; FY00 1.055; FY01 1.083; FY02 1.112; FY03 1.142; FY04 1.173; FY05 1.205; FY06 1.238; FY07 1.271
   Escalation rates applied to labor only, and the value provided for any given year was used with FY 1998 labor rates.
4. Cost elements other than 00 are level loaded (accepted practice by budget analysts) except for those fiscal years where known decreases or increases exist.
5. The FTE difference from FY 1997 to FY 1998 is due to the difference in annual hours per FTE.

In January 1998, Electrical Utilities will submit to DOE-RL layup plans and projected costs for 100-B, 100-KE, and 100-D substations.[16] See Fig. 7-1. It is speculated that comments, subsequent revisions, and approval to the layup plans may take until the end of FY 1998.

It is premature to anticipate what impact the following will have on existing manhour requirements:

- final land use recommendations under development by a joint federal, state, local, and tribal planning council, for effective use of assets no longer required by the federal government (due October 1997)

- pending decision by end of 1998 to restart FFTF or proceed with deactivation.

7.2.2 FY 1999. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- Project W-503, TWRS Phase I Privatization Facilities

- fuel removal from K Basins and cold vacuum drying systems

- liquid effluent facility enhancement construction

- B Plant deactivation support

- Building 324 cleanout and removal support

- typical Electrical Utilities operations and maintenance activities

Substation deactivation activities for 100-B, 100-KE, and 100-D, if approved, will probably occur during the first six months, reducing FY 1999 operations and maintenance costs by $225,000 and 1.6 FTE. Layup plans and projected costs for the 252-E and 252-W substations will be submitted in January 1999. No impact to manhour requirements is anticipated as it is thought that comments, subsequent

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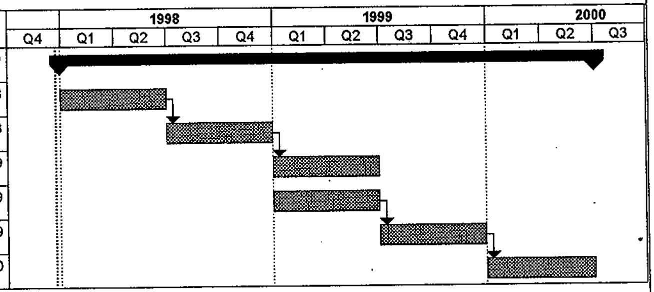
[16]Currently, the 100-N substation is not in service. A decision to reactivate the 100-N substation is pending and will be based upon 100 Area customer requirements regarding reliability or availability of the electrical supply system. A request for information of electrical power requirements was transmitted on August 6, 1997, to 100 Area customers with a response date of August 15, 1997. As of August 27, 1997, one response has been received with two responses outstanding. Finalization of the future of the 100-N substation will be included in the proposed layup plans. The estimated cost to restore the system to operation status is $140,000. The annual operational and maintenance cost is estimated to be $70,000 per year.

ELECTRICAL UTILITIES SUBSTATION LAYUP/DEACTIVATION ACTIVITIES

ID	Task Name	Start	Finish
1	**Substation Layup/Deactivation Activities**	**10/1/97**	**4/3/00**
2	Submit layup & cost plans for 100-B, 100-KE & 100-D to RL	10/1/97	4/1/98
3	Revisions, budget resolutions, and approval	4/2/98	9/30/98
4	Perform layup activities on 100-B, 100-KE & 100-D	10/1/98	4/1/99
5	Submit layup & cost plans for 252-E and 252-W	10/1/98	4/1/99
6	Revisions, budget resolutions, and approval	4/2/99	9/30/99
7	Perform layup activities on 252-E and 252-W	10/1/99	4/3/00



Project: Substation Layup/Deactivation
Date: 9/22/97

Task | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Milestone | Rolled Up Progress

Fig. 7-1

revisions, and approval to the layup plans may take until the end of FY 1999. Likewise, the pending decision by December 1998 to restart FFTF or proceed with deactivation should not noticeably impact requirements until FY 2000.

A feasibility study to relocate the central dispatch station, if funded, will be conducted this fiscal year.

7.2.3 FY 2000. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- Project W-503, TWRS Phase I Privatization Facilities
- completion of fuel removal from K Basins and cold vacuum drying systems
- liquid effluent facility enhancement construction

Prior fiscal year deactivation of 100-B, 100-KE, and 100-D substations will reduce the FY 2000 operations and maintenance budget by an additional $225,000 and 1.6 FTE.

Deactivating the 252-E and 252-W substations, if approved, should occur during the first six months, reducing FY 2000 operations and maintenance costs by $51,000 and 0.36 FTE.

Pending the results of the feasibility study and approval of necessary funds, the central dispatch station may be relocated this fiscal year.

7.2.4 FY 2001. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- Project W-503, TWRS Phase I Privatization Facilities
- completion of liquid effluent facility enhancement

Prior fiscal year deactivation of 252-E and 252-W substations will reduce the FY 2001 operations and maintenance budget by an additional $51,000 and 0.36 FTE.

No additional substation deactivation activities are forecast at this time.

7.2.5 FY 2002. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- Project W-503, TWRS Phase I Privatization Facilities
- 340 facility deactivation support

- typical Electrical Utilities operations and maintenance activities

No substation deactivation activities are forecast at this time.

7.2.6 FY 2003. Typical Electrical Utilities operations and maintenance activities will not require any increases from existing manhour requirements. Completion of Project W-503, TWRS Phase I Privatization Facilities, may require additional staffing. No substation deactivation activities are forecast at this time.

7.2.7 FY 2004. Typical Electrical Utilities operations and maintenance activities will not require any increases from existing manhour requirements. No substation deactivation activities are forecast at this time.

7.2.8 FY 2005. The following existing and known potential projects will not create any noticeable increases or reductions from existing manhour requirements:

- PFP deactivation support
- typical Electrical Utilities operations and maintenance activities

No substation deactivation activities are forecast at this time.

7.2.9 FY 2006. Typical Electrical Utilities operations and maintenance and PFP deactivation support activities will not require any increases from existing manhour requirements. However, a potential decline in deactivation and new construction projects may result in a reduction of direct-funded support activities. No substation deactivation activities are forecast at this time.

7.2.10 FY 2007. Typical Electrical Utilities operations and maintenance activities will not require any increases from existing manhour requirements. However, a potential decline in deactivation and new construction projects may result in a reduction of direct-funded support activities.

7.3 Electrical Transmission and Distribution System Upgrade Forecasts and Funding Requirements

Upgrades and improvements are forecast based on replacement standards as identified in reference documents, or equipment reliability without jeopardizing personal and system protection activities. Maintaining the electrical transmission and distribution systems is a core infrastructure activity to meet demand needs and assure reliable and cost effective systems are in place to meet mission requirements. Without upgrade and/or repair, the condition of the system would degrade to the point of complete failure. Loss of electrical systems across the Hanford Site could cause substantial delays to the mission and impact safety requirements.

Downsizing the electrical system when existing substations are no longer cost effective to operate[17] will reduce energy losses with a corresponding: (1) decrease in maintenance and infrastructure activities; and (2) increase remaining substation capacity utilization.

A spare parts inventory is maintained to effect prompt repairs of the transmission and distribution system. However, due to inconsistencies (manufacturer, model, year) within large electrical component types throughout the Site and cost, it is not feasible to maintain a complete inventory of all transmission and distribution replacement equipment. When necessary, based on testing or requirements, kind-for-kind replacements (expense or capital funded) are requested to maintain safe facility configurations. Equipment in good condition which has not exceeded its useful life, which becomes available due to substation deactivations or facility shutdowns, will be reused in lieu of new purchases. See Table 7-3.

7.3.1 FY 1998. A communications recorder for the 251-W dispatch center and a watthour meter test system require replacement at an estimated cost of $60,000 and $25,000 respectively. Electrical transmission and distribution system capital upgrade requests not approved and will be resubmitted for FY 1999.

7.3.2 FY 1999. Capital upgrade requests for a communications recorder for the 251-W dispatch center and a watthour meter test system will be resubmitted. See section 7.3.1.

7.3.3 FY 2000. No electrical transmission and distribution system capital upgrade requests are forecast.

7.3.4 FY 2001. The 100-B, 100-D, and 100-K substations will be bypassed following completion of layup activities at an estimated cost of $4,500,000. Relocation of the central electrical dispatch station is forecast at an estimated cost of $500,000.

7.3.5 FY 2002. No electrical transmission and distribution system capital upgrade requests are forecast.

7.3.6 FY 2003. The 251-W substation 230 kV breakers and transformers will require retrofit or replacement at an estimated cost of $10,000,000.

7.3.7 FY 2004. The 100-KW substation 13.8 kV switchgear will require retrofit or replacement at an estimated cost of $2,500,000.

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[17]Up front oil disposal and equipment excessing costs must be included in the life cycle cost analysis.

TABLE 7-3

FY 1998 - FY 2007 Capital Project/Equipment Forecast

	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
Capital Project Forecasts and Funding Requirements										
251-W Communications Recorder		$60,000								
Watthour Meter Test System		$25,000								
Bypass 100B, D, K substations				$4,500,000						
Relocate Dispatch Center				$500,000						
251-W (A-8) 230 kV breakers/transformers						$10,000,000				
100-KW 13.8 kV Switchgear*							$2,500,000			
300 Area 13.8 kV switchgear								$2,600,000		
351-B Sprinkler System								$500,000		
100-KW 230 kV breakers/transformers									$10,000,000	
Totals	$0	$85,000	$0	$5,000,000	$0	$10,000,000	$2,500,000	$3,100,000	$10,000,000	$0

*Will utilize equipment as available from 100 B and D.

Cost figures are estimates only. Studies will be conducted to obtain project estimates prior to requesting funding.

	FY 1998	FY 1999	FY 2000	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	FY 2007
Capital Equipment Forecasts and Funding Requirements										
HD Truck w/65' boom/man bucket		$302,000								
HD truck w/42' boom/man bucket (estimated)			$250,000							
HD truck w/51' boom/man bucket (estimated)					$250,000					
Totals	$0	$302,000	$250,000	$0	$250,000	$0	$0	$0	$0	$0

Cost estimates obtained from Fleet Operations.

7.3.8 FY 2005. The 300 Area main 351 and 352-E substations 13.8 kV switchgear are expected to require replacement at an estimated cost of $2.6 million. Another estimated $500,000 will be required to purchase and install an automatic sprinkler protection system for the 351B substation pursuant to DOE Order 5480.7A.

7.3.9 FY 2006. The 100-KW substation 230 kV breakers and transformers will require retrofit or replacement at an estimated cost of $10,000,000.

7.3.10 FY 2007. No electrical transmission and distribution system capital upgrade requests are forecast.

7.4 Capital Equipment Forecasts and Funding Requirements

Electrical Utilities currently maintains an inventory of 53 vehicles, miscellaneous small engines, portable hoists, trailers, and other equipment required to meet transmission and distribution system and customer demands.[18] Most of the equipment is peculiar to Electrical Utilities maintenance, and none of equipment could be eliminated without impacting the life cycle of the system or impacting the health and safety of employees.

7.4.1 FY 1998. One heavy duty truck, equipped with a 65-foot telescoping boom and man bucket essential for power line maintenance, has exceeded both useful life (9 years/80,000 miles) and replacement standards identified in Code of Federal Regulations (CFR), Federal Property Management Regulations, Subchapter G, Subpart 101-25.4 and 101.38.9, "Replacement Standards." Capital equipment requests for FY 1998 were not approved and will be resubmitted for FY 1999.

7.4.2 FY 1999. One heavy duty truck, equipped with a 65-foot telescoping boom and man bucket (see section 7.4.1). Total estimated cost for both the truck and man bucket is $302,000.

7.4.3 FY 2000. One heavy duty truck, equipped with a 42-foot telescoping boom and man bucket essential for power line maintenance, will have exceeded both useful life (9 years/80,000 miles) and replacement standards identified in Code of Federal Regulations (CFR), Federal Property Management Regulations, Subchapter G, Subpart 101-25.4 and 101.38.9, "Replacement Standards." Total estimated cost for both the truck and man bucket is $250,000.

7.4.4 FY 2001. No capital equipment requests are forecast.

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[18]Not included in this forecast are sedans, pickups, and carryall trucks, which are replaced by the General Services Administration (GSA) at the end of useful life. Also not included are a mix of small miscellaneous small engines and non-motorized equipment, which, given normal maintenance, should have a useful life of several more years. The implements are generally run-to-failure and replaced as expense, not capital, items.

7.4.5 FY 2002. One heavy duty truck, equipped with a 51-foot telescoping boom and man bucket essential for power line maintenance, will have exceeded both useful life (9 years/80,000 miles) and replacement standards identified in Code of Federal Regulations (CFR), Federal Property Management Regulations, Subchapter G, Subpart 101-25.4 and 101.38.9, "Replacement Standards." Total estimated cost for both the truck and man bucket is $250,000.

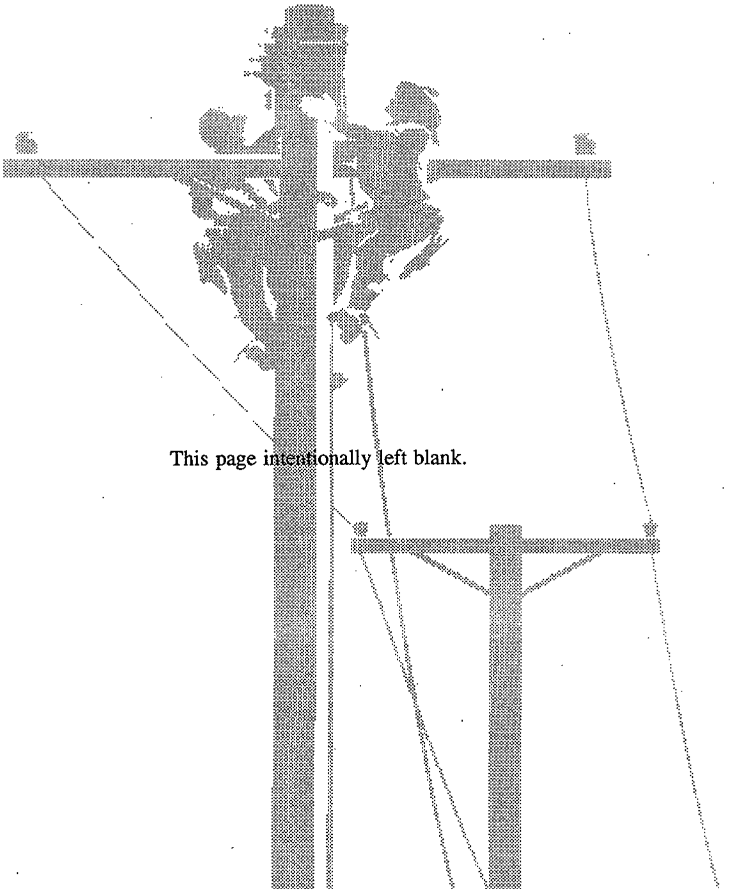
7.4.6 FY 2003. No capital equipment requests are forecast.

7.4.7 FY 2004. No capital equipment requests are forecast.

7.4.8 FY 2005. No capital equipment requests are forecast.

7.4.9 FY 2006. No capital equipment requests are forecast.

7.4.10 FY 2007. No capital equipment requests are forecast.



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APPENDIX A

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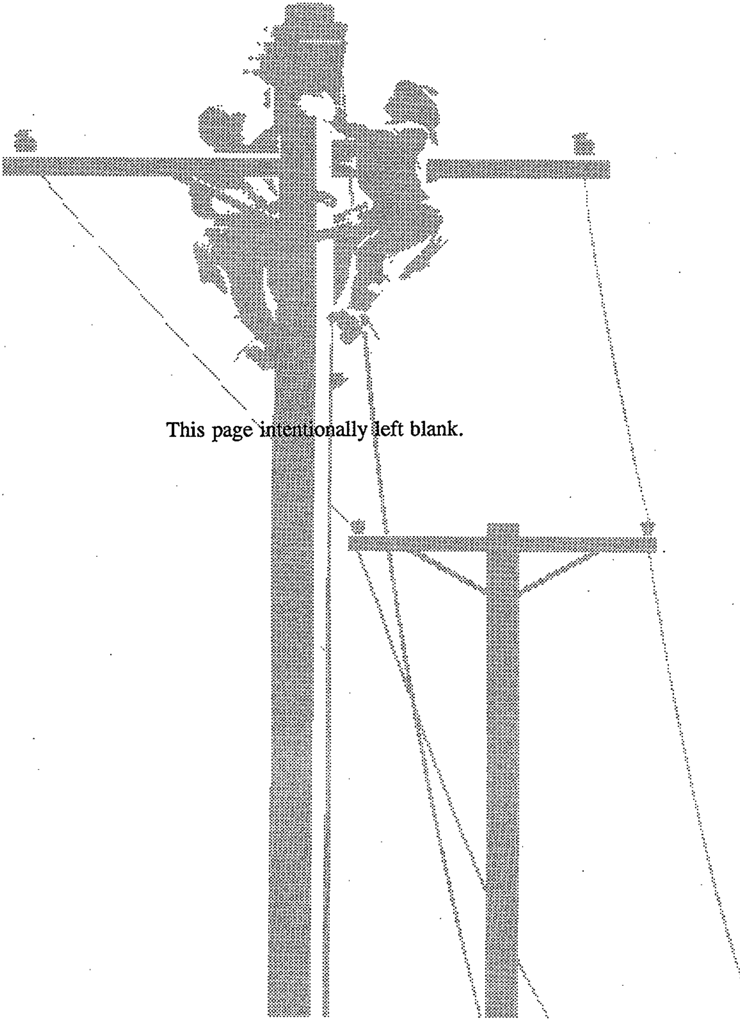
APPENDIX B

ELECTRICAL UTILITIES FY 1997 BUILDING BLOCKS

			Exempt	Non-exempt	Bargaining Unit	Totals
Section 4.2.1 Operations	Transmission	EU Funded FTE	2.4			2.4
		Direct Funded FTE				0.0
	Distribution	EU Funded FTE	6.4			6.4
		Direct Funded FTE	3.1			3.1
	Totals	EU Funded FTE	8.8			8.8
		Direct Funded FTE	3.1			3.1
		Total	11.9			11.9
Section 4.2.2 Administration	Distribution	EU Funded FTE	3.4	1.0	1.0	5.4
		Direct Funded FTE	0.1			0.1
		Total	3.5	1.0	1.0	5.5
Section 4.2.3 Maintenance and Management Support	Transmission	EU Funded FTE	1.4	0.6	4.0	6.0
		Direct Funded FTE				0.0
	Distribution	EU Funded FTE	3.4	1.4	8.2	12.9
		Direct Funded FTE	1.2		5.9	7.1
	Totals	EU Funded FTE	4.8	2.0	12.1	18.9
		Direct Funded FTE	1.2	0.0	5.9	7.1
		Total	6.0	2.0	18.0	26.0
Section 4.2.4 Support from Others	Operations	EU Funded FTE	1.1	0.0	0.3	1.4
	Maintenance	EU Funded FTE	0	0	0.4	0.4
	Administration	EU Funded FTE	0.2			0.2
	Totals	EU Funded FTE	1.3	0.0	0.7	2.0
Section 4.2 Workforce Organization	O&M	EU Funded FTE	18.3	3.0	13.8	35.1
		Direct Funded FTE	4.4	0.0	5.9	10.3



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APPENDIX C

ACTIVITY DESCRIPTIONS, START AND FINISH DATES FROM PROJECT HANFORD SUMMARY SCHEDULE
(Working Draft as of February 1997)

TANK WASTE REMEDIATION SYSTEMS

TANK WASTE CHARACTERIZATION	Start	Finish
M-44-00 Issue Tank Characterization Reports		09-30-99
Characterize Waste (all 177 tanks initial char)	10-01-96	09-29-00
TANK SAFETY ISSUE RESOLUTION	**Start**	**Finish**
M-40-00 Mitigate/Resolve Tank Safety Issues High Priority Watch List Tanks		09-28-01
Mitigate/Resolve Tank Safety Issues	10-01-96	09-28-01
TANK FARM OPERATIONS	**Start**	**Finish**
M-41-00 Complete Single Shell Tank Interim Stabilization		09-29-00
Interim Stabilize SST Farms/Surveillance & Maint	10-01-96	09-29-00
Deploy Cross-Site Transfer System	10-01-96	02-27-96
Continue Surveillance/Maint of SSTs	10-02-00	09-30-11
M-43-00 Complete Tank Farm Upgrades		06-30-05
Tank Farm Upgrades	10-01-96	06-30-05
Receive & Transfer Wastes/Oper DST Farms	10-01-96	09-30-11
RETRIEVAL	**Start**	**Finish**
106-C Sludge Removal	10-01-96	12-31-97
106-C Heel Removal/Cleanout (HTI)	07-01-99	09-29-00
106-C Heel Removal Tech/Deploy Systems (HTI)	10-01-96	07-01-99
SST Closure Demo (104-AX) (HTI)	10-01-96	09-29-00

M-45-00 Complete Closure of All Single Shell Tank Farms		09-30-24
SST Farm Closures	10-01-13	09-30-24
Post Closures Monitoring	10-01-24	Continue
DST Farm Closure	10-01-18	09-29-34
Deploy Initial SST Retrieval System (4 tanks)	10-01-96	12-31-03
Verify Retr Sys (4 tanks) & Retrieve SST Waste (30 tanks)	01-02-04	09-30-11
Deploy/Operate Initial DST Retrieval System	10-01-96	09-30-11
Demonstrate DST Retrieval Perf W-151	10-01-96	03-31-97
PROCESS WASTE	Start	Finish
Retrieve remaining SST Waste (113 tanks)	10-03-11	09-28-18
M-50-00 Comp Pretreatment Processing of Hanford Tank Waste		12-31-28
Retrieve DST Waste for Processing	10-03-11	09-29-28
Deploy Low Level Waste Immobilization Plant(s) Phase 2	10-01-04	09-30-11
M-60-00 Comp Vitrification of Hanford Low Level Tank Waste		12-31-24
LLW Immobilization	10-03-11	12-31-24
LLW Immobilization Facility Disposition	01-02-25	10-01-29
Deploy HLW Immobilization Plant(s) Phase 2	10-01-04	09-30-13
M-51-00 Complete Vitrification of Hanford HL Tank Waste		12-29-28
HLW Immobilization	10-01-13	09-29-28
HLW Immobilization Facility Disposition	10-02-28	09-30-33
LLW/HLW Pretreatment/Immobilization Phase 1	06-03-02	05-31-07
Deploy LLW/HLW Immobilization Phase 1 Plants	10-01-96	05-31-02
Continue Operations (optional)	06-01-07	05-31-11
Facility Disposition	06-11-11	05-30-14
IMMOBILIZED TANK WASTE STORAGE & DISPOSAL	Start	Finish
Prepare Facilities for LLW Storage & Disposal	10-01-96	09-30-20
LLW Storage & Disposal Operations	10-01-02	12-31-24
Close LLW Storage & Disposal Facilities	05-02-05	09-30-27
Post Closure Monitoring	01-02-25	Continue
Deploy HLW Phase I Interim Storage Facility (Mod to CSB)	10-01-96	09-30-02

Deploy HLW Phase 2 Interim Storage Facility Modules	10-01-08	09-30-24
Facility Disposition	10-01-42	09-30-43
Determine Cs/Sr Capsule Disposition (currently assumes overpack & store)	10-01-96	09-30-05
Ship HLW to Repository	10-01-35	09-30-39

WASTE MANAGEMENT

SOLID WASTE	Start	Finish
M-19-00 Complete Treatment and/or disposition of LLMW Specified Volumes		09-30-02
Direct disposal of LLMW	10-01-97	03-30-01
Waste Storage/Disposition Operations	10-01-96	continued
Thermal Treatment of Wastes	01-02-01	09-30-16
M-18-00 Complete WRAP 1 Construction/Initiate Operations		03-31-97
WRAP 1 Startup	10-01-96	03-31-97
WRAP 1 Operations	04-01-97	09-30-31
Deploy Phase 1 TRU Retrieval System	06-01-99	09-28-01
Phase 1 Retrieval	10-01-01	09-30-04
Deploy Caisson Retrieval System	10-01-02	09-30-05
Caisson Retrieval	10-03-05	09-30-09
Deploy Phase 2 Retrieval System	10-01-99	09-30-03
Phase 2 Retrieval	10-03-05	09-30-16
Ship Waste to Waste Isolation Pilot Project (WIPP)	10-01-98	09-30-31
M-32-00 Interim Status Dangerous Waste Tank System Hanford Federal		09-30-31
Leak Detection Upgrades	10-01-96	09-30-99
T-Plant Decontamination Service/RH-TRU Process	10-01-96	09-30-18
Canister Storage Bldg Complex Operations	10-01-01	09-30-39

LIQUID WASTE	Start	Finish
M-17-00B Complete Implementation of "BAT" for all Phase 2 Liquid Effluent Streams		10-31-97
200 Area Treated Effluent Disposal Facility Operation	10-01-96	09-30-33
200 Area Liquid Facility Enhancements	10-01-96	09-28-01
200 Area LETF Operation/242-A Evaporator Operation	10-01-96	09-30-35
300 Area Treated Effluent Disposal Facility Operation	10-01-96	09-30-26
300 Area 340 Facility Operation/Shutdown	10-01-96	03-29-02

SPENT NUCLEAR FUEL	Start	Finish
K-Basin Facility Upgrades	10-01-96	12-30-98
K-Basin Maintenance/Operations	10-01-96	09-28-01
Sludge Removal System Design, Installation & Startup	10-01-96	02-15-00
Sludge Removal Operations	03-02-98	11-30-00
Debris Removal Preparation/Operation	10-01-96	09-29-00
Water Treatment Operations	10-01-97	09-29-00
Water Treatment System Design, Installation & Startup	10-01-96	03-31-98
Acquire Multi-Canister Overpacks (MCOs)	10-01-96	09-30-99
Fuel Removal Design, Installation & Startup	10-01-96	03-31-98
Cold Vacuum Drying System Design, Installation & Startup	10-01-96	12-31-97
Cask Transport System Design, Installation & Startup	10-01-96	12-31-97
Fuel Removal Operations	01-02-98	12-30-99
Cold Vacuum Drying System Operation	01-02-98	12-30-99
Canister Storage Building Operation	01-02-98	06-30-09
Design/Construction & Startup CSB	10-01-96	12-31-97
Hot Conditioning System Operation	10-01-98	09-29-00
Preparation and Transfer Other Site Fuels to CSB	10-01-96	09-28-01

ANALYTICAL SERVICES	Start	Finish
222-S Laboratory Operation	10-01-96	09-30-25
Deploy Replacement HLW Lab	10-03-22	09-30-25
Continue HLW Lab Operations	10-01-25	Continued
LLW Lab Ops/WSCF & Commercial	10-01-96	Continued

FACILITY TRANSITION

PUREX	Start	Finish
M-80-00 Complete PUREX/UO3 Facility Transition Phase & Initiate S&M		07-31-98
Complete PUREX transition	10-01-96	07-31-97
300 AREA FUEL SUPPLY	**Start**	**Finish**
Complete 300 Area FSS Transition - Phase 2 Facilities	10-01-96	09-30-97
Complete 300 Area FSS Transition - Phase 3	10-01-96	09-30-98
Store and Ship Special Nuclear Materials (SNM)	10-01-96	09-30-98
Continue SNM Storage Outside 300 Area	10-01-98	09-30-05
PFP	**Start**	**Finish**
Complete Thermal Stabilization	10-01-96	05-03-02
Complete Misc Material Disposition	10-01-96	05-31-02
Complete Polycube Stabilization	10-01-96	09-30-99
Complete Solution Stabilization	10-01-96	06-24-98
M-83-02 Complete Identified Interim Actions (234-Z Ductwork Cleanout)		12-31-98
Complete Ductwork Cleanout	10-01-96	12-31-98
PFP Facilities Cleanup and Transition	10-01-96	09-26-05
SNM Vault Storage	10-01-96	Continued
B PLANT	**Start**	**Finish**
B Plant Canyon Ventilation Upgrade	10-01-96	09-09-98
Decouple B Plant From WESF	10-01-96	06-30-98
M-82-00 Complete B Plant Transition		09-30-99
B Plant Transition	10-01-96	09-30-98
WESF	**Start**	**Finish**
WESF Cleanup and Upgrades	10-01-96	09-30-98
Return Remaining Capsules to WESF	10-01-96	080-30-98
Cs/Sr Capsule Storage	10-01-96	10-03-11
Disposition Capsules	10-02-08	10-03-11
WESF Transition	10-04-11	10-02-13

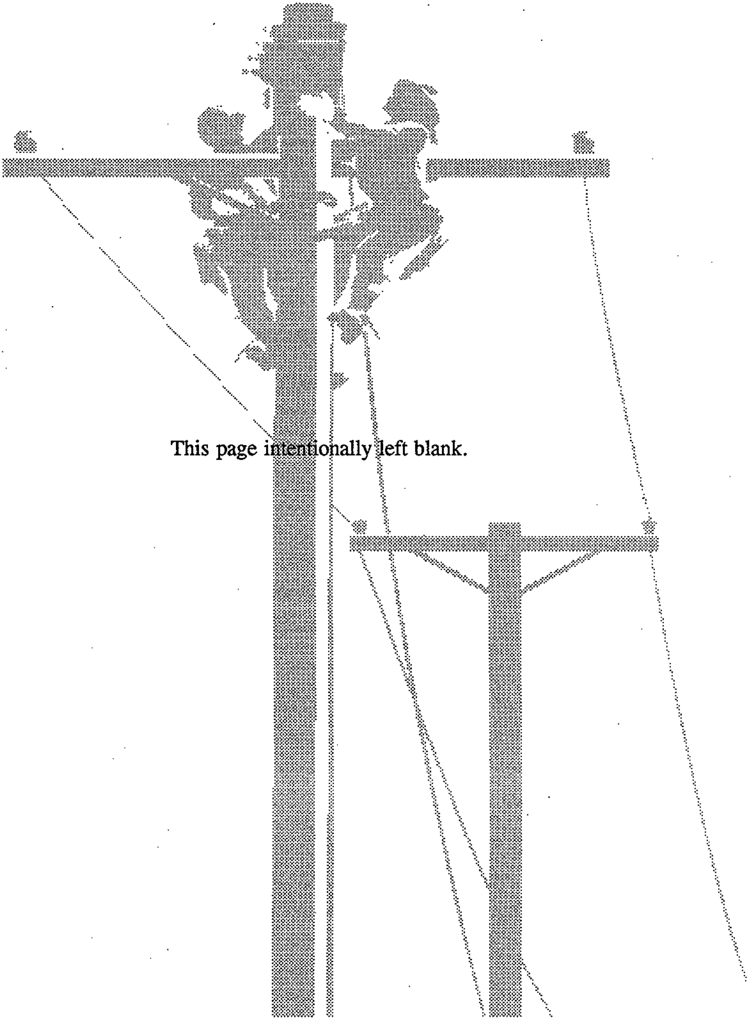
324/327 BUILDINGS	Start	Finish
Transition 324/327 Facilities	10-01-99	09-30-02
324/327 Surveillance, Maintenance and Operations	10-01-96	09-30-99
M-89-02 Complete Removal of 324 Bldg and Remove B-Cell MW and equipment		05-28-99
B-Cell Cleanout	10-01-96	08-20-99
K-BASINS	**Start**	**Finish**
K-Basins Transition	10-01-01	10-01-05
ACCELERATED DEACTIVATION	**Start**	**Finish**
Complete Remaining Deactivation	10-01-98	09-30-38
300 AREA REVITALIZATION	**Start**	**Finish**
Revitalize for use/deactivate 300 Area facilities	10-01-99	Continued
ADVANCE REACTOR TRANSITION	**Start**	**Finish**
Fuel Offload/IEM Cell Closure	10-01-96	04-24-00
Deactivate Auxiliary System	10-01-96	01-04-00
Note: FFTF in hot standby pending decision by end of 1998 to restart or proceed with deactivation.		
M-81-00 Complete FFTF Transition and Initiate S&M Phase		12-31-01
Complete FFTF Transition	01-05-00	03-30-01
Sodium Storage Facility Startup	10-01-96	01-31-97
Drain Sodium	02-03-97	02-28-00
Sodium Storage	02-03-97	02-28-00
Sodium Reaction	03-31-01	03-31-03
Sodium Reaction facility Design & Construction	10-01-98	03-31-01
Complete 309 Facilities Transition	10-01-96	09-30-98

ENVIRONMENTAL RESTORATION

	Start	Finish
N Reactor Deactivation	10-01-96	09-30-97
Reactor Dispositioning	10-01-24	09-29-34
Facility Surveillance and Maint/Dispositioning	10-01-96	Continued
100 Area Ancillaries Dispositioning/Reactor Interim Safe Storage	10-01-96	09-29-17
200 Area Ancillaries Dispositioning	10-03-16	09-30-24
Groundwater Remediation	10-01-96	09-30-10
M-16-00 Complete Remedial Actions for all non Tank Farm Operable Units		09-28-18
M-15-00 Complete the RI/FS (or RFI/CMS) for all Operable Units		12-31-08
M-13-00Q Submit 4 200 NPL RI/FS (RFT/CMS) Work Plans		12-29-06
Waste Site Remediation/ERDF Operations	10-01-96	09-29-34

SCIENCE AND TECHNOLOGY

	Start	Finish
WM and Operational Compliance	10-01-96	Continued



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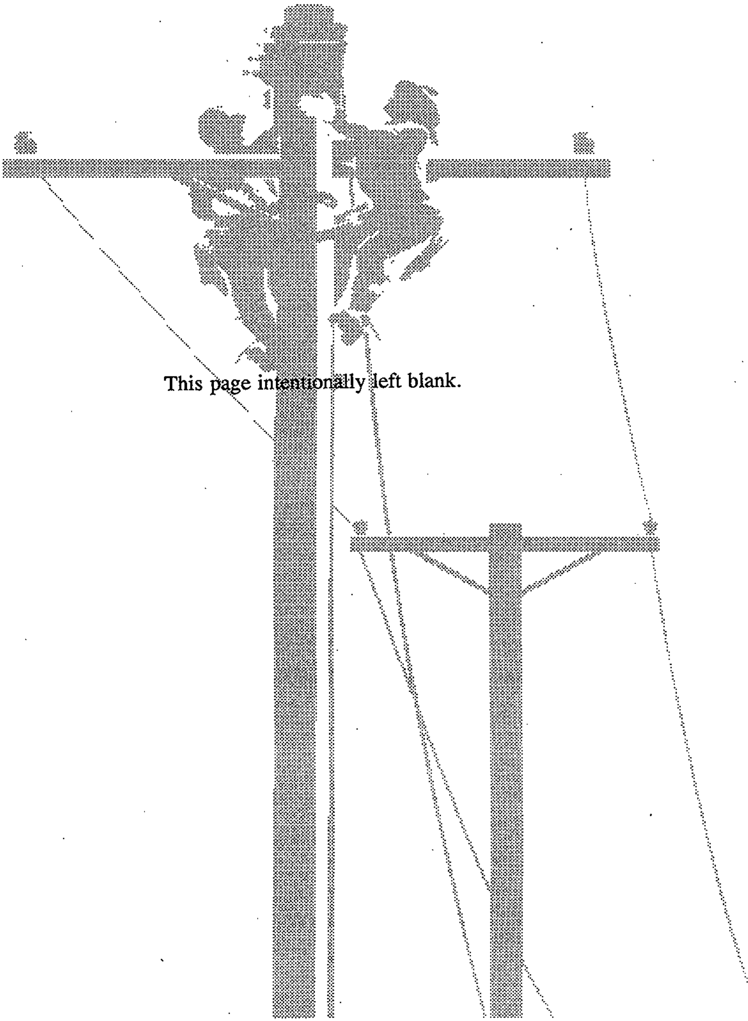

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