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Proposals for Monitoring the Performance of Electric Utilities

Ernst & Whinney

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Abstract

Recent World Bank studies have shown a declining trend in power sector performance in the developing countries and recommend giving greater emphasis to rehabilitation and maintenance, and to improving operational performance.

This report presents a system for improving electric utility efficiency through the identification and analysis of three sets of performance indicators covering generation, transmission and distribution, and commercial operations. The indicators measure physical inputs and outputs. The system is intended to supplement the more usual financial tests used to measure utility performance, which are not covered in this report.
Foreword

This manual was developed by the utility audit firm of Ernst & Whinney under contract with the World Bank. It is intended to serve as a guide to utility managers in developing countries to identify operations areas where efficiency gains can be made, and to design and prioritize programs to achieve these gains. A secondary objective is to identify and define a series of performance indicators which measure physical inputs and outputs, to supplement the financial performance measures which are widely used in the Bank and elsewhere.

Although typical performance data is included, derived from 27 utilities in the U.S. and elsewhere, it is not intended that this data be used to establish performance targets or benchmarks; rather, the management-improvement system developed in the manual depends heavily on trend analysis—that is, comparing performance intracompany rather than inter-company.
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CHAPTER I

INTRODUCTION AND EXECUTIVE OVERVIEW

BACKGROUND AND PURPOSE OF MANUAL

Electric power utilities all over the world face increasing pressures to achieve improvements that will move them toward the most cost effective level 1/ of operations. To do so, utilities must establish a means for regular identification of opportunities for improving cost effectiveness, develop targets, priorities and plans to capitalize on these opportunities, and monitor results as plans are implemented and targets achieved.

The purpose of this manual is to describe a management tool that utility managers and staff can use to identify and achieve cost effective improvements. This tool is called the Performance Indicator/Management Reporting System (PI/MRS).

The essence of all management is to influence the future.

OVERVIEW OF PI/MRS PROCESS

The PI/MRS is a critical element in a results-oriented management approach. Experience has shown that a results-oriented management approach helps ensure the cost-effective achievement of a utility's overall goals and objectives. Figure I-1 demonstrates how the PI/MRS fits into an overall results-oriented management approach.

The first steps in a results-oriented management approach include the defining of a corporate mission (often referred to as the overall mission) and the establishment of long-term corporate objectives that will lead to the accomplishment of the mission. These are often done as part of the strategic planning process. The utility then develops an organizational structure and defines reporting relationships that best contribute to achieving the mission and long-term corporate objectives. 2/ Annual operating objectives (at all

1/ Throughout this manual, the term "cost-effective level" will be used. This term is defined as the operating level of the utility that produces the greatest net benefits (benefits minus costs). Benefits can be actual monetary savings, efficiency improvements, improved capital plant life, social goodwill, or any other benefit that the utility believes is appropriate. Costs are similarly interpreted in broad terms, not simply as actual monetary costs.

2/ The organization and reporting relationships are noted by a dotted line in Figure I-1 because they are not directly part of the results-oriented approach. Without an effective organizational structure and reporting relationships, however, a utility will not be able to achieve its mission and objectives cost effectively.
FIGURE I-1

INTEGRATION OF PI/MRS PROCESS WITH RESULTS-ORIENTED MANAGEMENT APPROACH

- STRATEGIC PLAN
  - CORPORATE MISSION
    - LONG-TERM CORPORATE OBJECTIVES
      - ORGANIZATIONAL STRUCTURE & REPORTING RELATIONSHIPS
    - ANNUAL OPERATING OBJECTIVES
      - QUALITATIVE ASSESSMENT
        - IDENTITY PERFORMANCE INDICATORS & DATA BASE THAT ASSIST IN MEASURING THE ACHIEVEMENT OF THE OBJECTIVES
          - QUANTITATIVE ASSESSMENT
            - ANALYSIS OF PERFORMANCE INDICATORS & IDENTIFICATION OF COST SAVINGS & EFFICIENCY IMPROVEMENTS
              - PI/MRS PROCESS
                - DEVELOP OF ACTION PLANS & SETTING OF TARGETS (QUANTITATIVE GOALS) TO ACHIEVE COST SAVINGS & EFFICIENCY IMPROVEMENTS
                  - MONITORING & REVISITING OF ACTION PLANS THROUGH ANALYSIS OF REPORTING DOCUMENTS
                    - INTEGRATION OF PI/MRS PROCESS INTO THE HUMAN RESOURCE ASPECTS OF THE UTILITY TO ENSURE FULL ACHIEVEMENT OF PLANS

OVERALL RESULTS-ORIENTED MANAGEMENT APPROACH
levels of the utility) are also developed to assist in achieving long-term corporate objectives.

The PI/MRS process is an integral part of the successful achievement of these annual and long-term objectives in a cost effective manner. Both qualitative (i.e. management assessment, judgment and experience) and quantitative approaches are necessary to achieve and monitor a utility's goals and objectives effectively. The PI/MRS process is an important and useful quantitative approach because it identifies, coordinates and monitors cost-effective improvements in a structured manner that is easy for utility managers to use and update.

**IDENTIFICATION OF PERFORMANCE INDICATORS AND DATA BASE IN THE PI/MRS**

The cornerstone of the PI/MRS is its quantitative performance indicators, which assist in measuring—at appropriate management levels—whether the utility is achieving its objectives. The identification of appropriate performance indicators is critical. Appropriate performance indicators should be developed by asking the question, "What are the objectives (of the entire utility and the particular function) and what quantitative performance indicators can be used to assist in measuring the achievement of these objectives?" at all management levels in the utility. 1/ Once the appropriate list of quantitative performance indicators is identified, the utility must determine what data are necessary to compile the indicators and whether the data are readily available. If the data are not readily available, the utility decides whether the data collection effort would be cost effective and, if not, selects alternative performance indicators. A reporting system (with current and historical data) that ensures accurate and speedy reporting and analysis of the indicators is developed after the desired set of specific indicators and their associated data have been identified. Chapter II of this manual tells how to build the historical data base and the reporting system. Chapters III through V identify performance indicators for different management levels of the generation, transmission and distribution, and commercial activities, respectively, of utility operations. 2/

---

1/ Qualitative measures must also be considered in fully measuring whether a utility is meeting its objectives. These qualitative measures should be used with the quantitative measures discussed in this manual.

2/ The scope of this manual is limited to the generation, transmission, distribution, and commercial activities of a utility. A full scope PI/MRS would also include financial, planning, and construction activities.
USE OF THE PI/MRS PROCESS TO IDENTIFY, ACHIEVE AND MONITOR COST EFFECTIVE IMPROVEMENTS

The steps necessary to identify, achieve, and monitor cost effective improvements through the PI/MRS process are:

**Step 1:** Determine whether the utility's performance measures indicate that the utility is achieving its objectives and operating at the most cost-effective level.

**Step 2:** Based on Step 1, identify possible cost-effective improvements that will enable the utility to (1) achieve its objectives more fully and (2) move to a more cost-effective level of operations.

**Step 3:** For those areas where cost-effective improvements can be made, develop cost-beneficial action plans that will assist the utility in achieving the improvements. For each plan, identify (1) specific steps to accomplish the plan, (2) costs and benefits of the plan, and (3) targets and milestones that will indicate effective implementation of the plan.

**Step 4:** Monitor and revise the action plans (including the targets, costs and benefits, and milestones) to ensure that they are implemented as quickly as possible and remain cost effective. This step is facilitated by using PI/MRS reporting documents which are fully described in Chapter II.

**Step 5:** Integrate the process into (1) the planning and budgeting system, by using the performance targets to assist in setting budgets, and (2) the human resource aspects of the utility, by ensuring that personnel understand the process, that its purpose is clearly communicated, that appropriate training is provided, and that employees are motivated to ensure effective use of the process.

These steps are explained more fully in Chapter II, and case study examples are provided in Chapters III, IV, and V.

LIMITED SCOPE PI/MRS

For some utilities, particularly those with severe data collection obstacles or those that want to test the PI/MRS approach before adopting it fully, a "limited scope" PI/MRS that addresses a restricted number of performance indicators may be desirable. This approach focuses on the 20 to 25 critical (most important) performance indicators. Top management can use these indicators as a basis for identifying desirable investigations by departmental managers of potentially significant cost effective improvements. This approach, unlike the comprehensive PI/MRS approach, does not
examine potential cost effective improvements in all functional areas nor all management levels of the utility. Only the comprehensive PI/MRS is described in this manual, however, a limited scope approach is developed in a similar fashion.

BENEFITS OF THE PI/MRS

The benefits of the PI/MRS fall under five distinct areas:

- Resource utilization.
- Quality of service
- Management control of performance.
- Management of human resources.
- Plant design standards.

IMPROVED RESOURCE UTILIZATION

The most obvious benefit of an effective PI/MRS process is the continual, organized identification and implementation of improvement plans designed to utilize resources better. Experience has shown that the benefits to a utility from effectively using the PI/MRS can be significant. Examples illustrating benefits that have been or are currently being achieved using this approach include:

- Annual savings of $1 million (2% of total maintenance costs) for a utility that implemented improvements to generation maintenance. 1/
- Annual savings of $500,000 to $1 million (0.1% of total generation costs) for a utility that implemented performance monitoring systems for generation units.
- Annual savings of more than $1 million (3% of total distribution costs) for a utility that implemented better work-forecasting information in its distribution operations.
- Annual savings of $2 million to $6 million (2% to 5% of billing cycle revenue) for one utility and $9 million to $11 million (3% to 4% of billing cycle revenue) for another utility that implemented improvements reducing the accounts receivable lag.
- Annual savings of $3 million to $5 million (1% to 2% of billing cycle revenue) for one utility and $500,000 (0.5% of billing cycle revenue) for another utility that implemented improvements reducing the time between meter reading and sending bills to customers.

1/ In this manual, US dollars will be used as the currency.
The cumulative benefit of these types of annual savings can be significant in the long term, especially for a utility experiencing rapidly escalating costs.

The PI/MRS is also useful in evaluating the appropriate use of capital plant. For example, proper use of the PI/MRS will identify the need for and associated net benefits of retrofitting or upgrading plant.

QUALITY OF SERVICE IMPROVEMENT

Experience has shown that cost-effective improvements in the reliability and quality of service provided to customers often result from the application of a PI/MRS.

EFFECTIVE MANAGEMENT CONTROL OF PERFORMANCE

The PI/MRS process facilitates effective management control in several ways:

- It establishes a system for regular review of cost effectiveness that is structured to encourage managers to achieve cost effective improvements. This is accomplished through regular review of performance indicators and by incorporating the PI/MRS process into the planning and budgeting cycle.

- It helps produce useful management reporting information that allows each management level to make reasoned decisions and act as cost effectively as possible. The PI/MRS provides measures of accountability at each level, permitting accurate evaluations of past performance and the implementation of steps that improve future performance. This "hierarchy" of information enables each manager to deal with only the information necessary to do his job, and it emphasizes the need for upper management to focus more on strategic issues.

- It provides planning and replanning processes that focus on identifying cost effective improvement opportunities. The reporting process also tracks the progress of the action plans and allows for necessary revisions.

- It encourages managers to focus their efforts on making future improvements. The focus on future cost effective improvement actions is reinforced through the entire PI/MRS process. This focus differs from that of traditional accounting systems which record costs but do not relate them to the processes that generated to those costs.
EFFECTIVE MANAGEMENT OF HUMAN RESOURCES

The PI/MRS facilitates effective management of human resources by providing managers and staff with easily understood measures of their specific contributions to common corporate objectives. Although most people are motivated to excel, they often lack performance measurements against which they can evaluate their efforts and be evaluated by others. It is a well established fact that people are strongly motivated by any indication that their activities are of interest to others no matter whom. It is also clear that without effective participation by employees, the utility's objectives cannot be reached. The PI/MRS process provides the means both of demonstrating interest and a vehicle for participation.

PLANT DESIGN STANDARDS

Although it is not discussed at length in this manual, an indirect benefit of the PI/MRS is an improved understanding of the costs and benefits of different plant design standards. Thus, when plant standards are evaluated and designed, they should be considered carefully to ensure that the plant operates at the most cost effective level over its entire life. These standards should be reviewed from time to time to take account of changes in the relative values of materials and labor.

IMPORTANT CONSIDERATIONS IN THE USE OF PI/MRS

As with any management tool, the PI/MRS must be carefully used. Important considerations in this regard are discussed in the following paragraphs.

Both managers and staff must view the PI/MRS as nothing more than a tool that assists in identifying and achieving cost effective improvements. The motivation to implement change should come from the employees themselves perceiving the system as enhancing their ability to influence processes and use of resources towards improved performance.

The PI/MRS process must be used at each level only by appropriately qualified utility personnel. Senior managers must be responsible for initiating the PI/MRS and must ensure that middle and lower level management receive thorough instruction before each is entrusted with carrying out the process. It is equally important that all staff are aware of the system, are informed about its results and committed to its success by participation in the setting of objectives. Where organized labor exists, it is most important that its officials are fully briefed and, ideally, that they are persuaded to support the changes that affect labor. If this pattern is not followed, the benefits of the process are not likely to be fully achieved.

The PI/MRS is only one of several management tools that should be used to identify and achieve cost effective improvements. Any analysis of whether a utility has achieved its objectives must include qualitative assessment and judgment by management of the utility's performance.
The performance indicators need to focus on those actions that are controllable by utility management. Thus, great care must be taken to select appropriate indicators. Also, the trend analysis of performance indicators must consider changes in external variables (such as changes in customer load patterns) which might account for—or contribute to—changes in the performance indicators.

Too often, short-term cost-saving decisions are made that actually produce long-term costs that outweigh associated benefits. A comprehensive, detailed cost-benefit analysis process—one that considers all of the short and long-term costs and benefits—is essential to the PI/MRS process.

The PI/MRS does not take into account resource substitution across a utility's operating activities. For example, a utility may install a new data processing system that lowers one area's operating costs while increasing costs for another area. Unless the effects of such substitutions are understood, resulting performance indicators might be misinterpreted as showing increased productivity in operations and decreased productivity in data processing. Thus, a full understanding of the PI/MRS process is not sufficient by itself. Compilation of data must also be structured to provide information that can be evaluated in its proper context.

ORGANIZATION OF MANUAL

This manual is organized so that individual sections can be provided to those employees for whom the information will be most useful. Reprinting in looseleaf format may be desirable for this purpose. Those at lower management levels need not read the entire manual. Chapters I and II which provide a generic description of the PI/MRS process, should be read by all those who will apply the methods advocated. Chapter III, IV and V then deal with, respectively, generation operations, transmission and distribution operations, and commercial operations including customer services, supply management, human resources support, and accounting. With this division of chapters, operating managers can read the parts that apply directly to their specific area(s) of responsibility.

In the applications chapters, data from a hypothetical utility are used to demonstrate how the PI/MRS can be applied. These specific numbers are based on real utility operating experience. In practical use of the PI/MRS process, however, data for a utility would be based on analysts' assumptions and on actual data for the utility. To provide some dimension to the hypothetical utility, several general assumptions about its operations have been made:

* Annual revenue is $500 million.
* 3,000 large consumers account for $200 million in revenue and 3 million small consumers account for $300 million in revenue.
* Interest cost is 15%.
* The utility has five operating divisions.
The utility has three management levels—chief executive, general managers, and managers.

Specific assumptions for each of the three applications areas (generation, transmission and distribution, and commercial) are made in the appropriate chapters.

In the applications chapters, actual performance indicator figures are derived from a survey by Ernst & Whinney of 27 utilities in the United States and other countries. This data base provides (1) meaningful numbers that can be compared with the hypothetical utility's numbers and (2) useful information for utilities that implement the PI/MRS process.
CHAPTER II
GENERIC DESCRIPTION OF THE PI/MRS PROCESS

INTRODUCTION

This chapter—which is intended to be used in conjunction with each of the three "applications" chapters that follow—is designed to provide a detailed generic description of the PI/MRS process. This process consists of six major elements:

* Identifying useful staffing and operational performance indicators.
* Developing the performance indicator data base and reporting requirements.
* Identifying possible cost effective improvements and developing action plans to achieve them.
* Developing reporting documents to (1) monitor the cost-effective improvement plans and (2) provide management with information essential for managing the utility's operations.
* Integrating the PI/MRS process with the planning and budgeting cycle to provide incentive for full achievement of cost economies and efficiency improvements.
* Integrating the PI/MRS process into the human resource aspects of the utility.

Each of these elements is discussed below in generic terms. In Chapters III through V, each element is discussed in specific terms of the "applications" presented in those chapters.

IDENTIFYING USEFUL STAFFING AND OPERATIONAL PERFORMANCE INDICATORS

The basis of the PI/MRS is the quantitative performance indicators that assist in measuring--at appropriate management levels--the achievement of the utility's objectives. 1/ The identification of useful performance indicators is tied to the utility's overall objectives which, in turn, are translated into specific objectives for the generation, transmission and

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1/ As noted in Chapter I, one must also consider qualitative measures (i.e. management assessment and judgment) when determining whether a utility is meeting its objectives.
distribution, and commercial areas of the utility. The specific objectives (discussed in the applications chapters) are then used to identify a menu of indicators that can assist in achieving the objectives at three levels--manager, general manager, and chief executive.

Performance Indicators at the chief executive level are termed critical indicators, because of their importance to the PI/MRS process. These critical indicators are presented in Exhibit II-1.

Because the objectives and performance indicators in the applications chapters have been developed for a generic utility, the menu of indicators presented here should be considered only as a guide in developing the performance indicators for a specific utility's needs. Although utilities share the same types of objectives, their priorities will differ according to specific circumstances that will change both the hierarchy of the performance indicators and the actual performance indicators to be analyzed.

**DEVELOPING THE PERFORMANCE INDICATOR DATA BASE AND REPORTING REQUIREMENTS**

The PI/MRS data base consists of both historical and current data for performance indicators. Both components are critical. Historical data permit review of past performance (especially trends over time), while the latest data provide information on the recent operations.

The latest data can be used effectively, only if they are made available for management review shortly after they are gathered. This requires a collection process that delivers fresh data to a central point. Appropriate data bases can be assembled by using the following steps:

- Identifying the data needed to compute the selected performance indicators.
- Determining what data are available.
- Determining the cost effectiveness of collecting data not available now.
- Determining a preliminary set of useful indicators.
- Reviewing the preliminary set of useful indicators and determining whether additional indicators should be considered.
- Determining the final set of useful indicators and designing the collection process (either mechanized or manual) to develop a data base that can be collected, analyzed to give indicators and forwarded with little delay to meet reporting requirements.
- Field testing the procedures to ensure that the data base serves its purpose as intended on a regular basis.
- Organizing data base information for analysis.
Appendix II provides a detailed discussion of each step. Specific data needed to calculate the various indicators for each area of application are identified in the applications chapters that follow.

IDENTIFYING POSSIBLE COST-EFFECTIVE IMPROVEMENTS AND DEVELOPING ACTION PLANS TO ACHIEVE THEM

This is the most important element if the PI/MRS process is to yield improvements. Data from the utility and from other utilities can be used to identify desired performance levels for each of the utility's performance indicators. 1/ A potential opportunity for cost effective improvement is indicated when the utility's performance indicator data show that it is not operating at the desired performance level in a particular area. An analysis can then be performed to determine the feasibility and benefits of having the utility move toward the desired performance level and achieve the potential cost effective improvements.

If the analysis indicates that the utility should attempt to achieve the desired performance level, management should develop an action plan that specifies (1) the steps to be taken; (2) the schedule, targets, and milestones for taking each step; and (3) the costs and benefits of each step and of the overall action in each case. Targets should be expressed as performance indicators to the greatest extent possible. This allows the utility more easily to monitor changes over time and determine the effectiveness of the plans, so that the plans can be adjusted to achieve the desired performance level better.

The following paragraphs provide a detailed generic discussion of the steps needed to produce cost effective action plans. These steps are:

- Identifying desired performance levels and comparing them with the utility's actual performance level--to identify potential cost-effective, improvement opportunities.
- Determining feasibility and cost benefits of achieving the desired performance level.
- Developing the action plan.

IDENTIFYING DESIRED PERFORMANCE LEVELS AND COMPARING THEM WITH THE UTILITY'S ACTUAL PERFORMANCE LEVEL TO IDENTIFY POTENTIAL COST-EFFECTIVE, IMPROVEMENT OPPORTUNITIES

An effective method for determining whether a potential for improvement exists is to develop a desired performance level for each

1/ A desired performance level is that level believed to be the most cost effective. Detailed analysis is required to ascertain whether the level is in fact the most cost effective.
A performance indicator that is measured against the utility's actual performance. Differences revealed by this comparison may indicate the utility is not operating at the most cost-effective or efficient level possible. A substantial degree of management judgment must be applied in setting the desired performance level and in determining whether there is a difference between this level and the utility's actual performance level.

The desired performance level developed by the utility is simply a benchmark to use in the PI/MRS process. The utility will quite possibly find that it is not cost-effective to attain this level. Additionally, detailed investigation may indicate that the initial desired performance level should be adjusted.

The substeps for performing this are:

- Examining aggregate company statistics and aggregate performance indicators to obtain an overview that will assist in identifying desired performance levels and potential cost effective improvements.
- Using various quantitative analysis techniques to collect information on potential desired target levels for specific performance indicators.
- Using management analysis to (1) determine desired performance levels for specific performance indicators and (2) compare the desired performance levels to the utility's actual performance levels to identify potential cost effective improvements.

**Aggregate Analysis.** The starting point in the aggregate analysis is to build an overall cost matrix of the utility's operations for the past several years. 1/ This cost matrix will indicate major expenditures and will reveal major shifts in the relative size of the cost centers. Table II-1 shows the hypothetical cost proportions of a utility with the three main operating functions identified in the three applications chapters. The percentages for the operations-related budget are typical for a utility with little hydro capacity: 60% for fuel, 15% for generation (not including fuel), 9% for transmission and distribution, and 16% for commercial operations (see Figure II-1). 2/ By showing relative weights of cost centers, it is easier to identify areas of potential cost-effective improvement in a utility. The rate base related cost inputs are also presented to show the utility's entire cost.

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1/ Since aggregate analysis is used in analyzing overall utility operations, it is not discussed in the applications chapters, which deal with specific activities.

2/ These percentage figures are only estimates and will vary significantly from utility to utility.
Table II-1

SAMPLE OF COST MATRIX FOR HYPOTHETICAL UTILITY
($'000)

<table>
<thead>
<tr>
<th>Operations related</th>
<th>Generation</th>
<th>Transmission &amp; distribution</th>
<th>Commercial&lt;sup&gt;a/&lt;/sup&gt;</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Personnel wages &amp; benefits</td>
<td>20,000</td>
<td>15,000</td>
<td>22,500</td>
<td>57,500</td>
</tr>
<tr>
<td>Fuel</td>
<td>228,000</td>
<td>--</td>
<td>--</td>
<td>228,000</td>
</tr>
<tr>
<td>Supplies and services &lt;sup&gt;b/&lt;/sup&gt;</td>
<td>37,000</td>
<td>19,200</td>
<td>38,300</td>
<td>94,500</td>
</tr>
<tr>
<td></td>
<td>285,000</td>
<td>34,000</td>
<td>60,800</td>
<td>380,000</td>
</tr>
<tr>
<td>Rate base related &lt;sup&gt;c/&lt;/sup&gt;</td>
<td>50,000</td>
<td>60,000</td>
<td>10,000</td>
<td>120,000</td>
</tr>
<tr>
<td>Total</td>
<td>335,000</td>
<td>94,200</td>
<td>70,800</td>
<td>500,000</td>
</tr>
</tbody>
</table>

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<sup>a/</sup> Includes customer services.
<sup>b/</sup> Includes contractor services.
<sup>c/</sup> Includes such items as depreciation, amortization, taxes and income.

The overall cost table can be examined on the basis of kWh to determine any unusual changes. If possible, the cost/kWh should first be adjusted to eliminate the effects of inflation.

FIGURE II-1

60% fuel
16% commercial operations
9% transmission and distribution
15% generation
Quantitative Analysis Techniques. Following examination of aggregate analysis information, the utility must apply quantitative data analysis techniques to specific performance indicators, thereby identifying potential desired performance levels, which may in turn indicate possible cost effective improvements.

Several types of quantitative data analysis techniques are available to assist in this process. These techniques are either intracompany (comparing the utility to itself) or comparative (comparing the utility to other utilities). Most of these techniques yield information on trends, which can serve as useful signals for developing improvement opportunities. Some of the more powerful data analysis techniques are:

- **Intracompany Comparable Work Units** - Utilities often contain work units that perform similar types of work under similar operating environments. This occurs when similar work is performed in several areas of a company (for example, work performed at power stations or in a decentralized utility that might have a billing and collection group in several of its regional operating divisions). When this is the case, the performance in these work units can be examined and compared to identify the potential for cost-effective, improvement opportunities.

  The hypothetical utility, used as an example in this manual, is assumed to have five regional operating divisions. Thus, a convenient work unit analysis is to compare performance of the five divisions. Based on this analysis, the division with the best performance can serve to identify opportunities for improvement in some or all of the other four divisions.

- **Intracompany Management and Efficiency Studies** - Within a utility, management and efficiency studies can be conducted to determine the reduction of time, effort, or resources that could be made under ideal conditions. Often this analysis consists of a review of a manufacturer's design criteria to determine if the design criteria are also applicable for the utility under ideal conditions. Such studies are very useful because they provide a frame of reference to determine desired performance levels.

- **Analysis of Intracompany Performance Indicators Over Time** - Examining a utility's performance over time is often useful for identifying potential cost-effective, improvement opportunities. This is especially true if the performance indicator is based on some type of physical component (such as customers/staff) that should either stay constant or improve over time. Graphic presentations are very useful for showing these trends over time. (Specific examples are shown in the applications chapters.)

- **Comparative Performance Indicator Analysis** - Comparing one utility's performance with that of another is an analysis
technique that must be used cautiously. This technique is often used incorrectly and, consequently, is quite controversial. It can be useful, however, if the comparison is used only to identify possible desired performance levels (and corresponding cost-effective improvement opportunities) that should be investigated more thoroughly. The important aspects of this technique are:

- Only the performance measures of similar systems or similar types of systems can be used for comparison.

- Utilities should be compared on an absolute basis (e.g., for one year) or over time (e.g., changes from 1979 to 1982). Each measure has advantages and disadvantages; thus, comparisons that use both bases are recommended.

- Performance measures that have a monetary value (i.e. \( \$/\text{kWh} \)) should be compared with caution recognizing that utilities in different countries are affected by inflation, exchange rates and other dissimilar factors.

Management Analysis. Utility managers must exercise their judgment (based on experience and the utility's own operating characteristics) in using the various quantitative techniques to identify a desired performance target level. Managers can then determine any difference between the desired performance level and actual performance, thereby indicating a potential cost-effective improvement opportunity.

DETERMINING FEASIBILITY AND COST BENEFITS OF ACHIEVING THE DESIRED PERFORMANCE LEVEL AND ESTIMATED COST-EFFECTIVE IMPROVEMENTS

Once a desired performance level is shown to be different from recent experience, alternatives for achieving performance level improvements are identified. This is a critical step, requiring rather extensive analysis to determine if improvements can be implemented in a cost-effective manner. Where the analysis in the previous step provides a rough estimate of the desired performance level, analysis in this step identifies the specific opportunity for improvement. Thus, it is best to evaluate the costs and benefits for different performance levels, because the desired performance level indicated initially may not be the most cost-effective level of operation for the utility. When this is the case, the level identified as the most cost-effective becomes the desired performance level. If, however, analysis shows that the present operating level is the most cost-effective, the analysis should be stopped.

An important consideration in examining the feasibility and cost/benefits of improving performance by attaining different performance levels is determining the phases and priorities that will ensure the quickest possible achievement of savings. The following approach is recommended:
Phase I - Examine performance levels that achieve cost-effective improvements that use no new technology or new systems. Experience shows that immediate savings can often be achieved by reorganizing work flows, increasing labor productivity, and improving management processes. This phase produces immediate cost savings with little capital outlay.

Phase II - Consider the introduction of new technology and new systems that can increase the savings achieved in Phase I, and gradually move toward the most effective level of operations.

This approach will usually result in gradual performance-level improvement that eventually attains the desired performance level, but also achieves more immediate, interim improvements.

While it is beyond the scope of this manual to present detailed cost benefit analysis of the different improvement analyses, utility analysts should employ such an analysis. This helps ensure that the analysis of alternatives fully considers such factors as phasing in and out of benefits and costs, transportation costs, import taxes, net present value, internal rate of return, cost of borrowed money, and alternative investment options.

DEVELOPING THE ACTION PLAN

After opportunities for improvement have been clearly identified and priorities have been established, a complete action plan should be developed. The complete action plan will:

- Identify the specific steps that will achieve improvement.
- Identify the schedule, targets, and milestones for each of the steps and for the overall action plan. Ideally, the targets should be based on the utility's performance indicators, which should show gradual improvement of the performance indicators as the plans are implemented.
- Identify the effects on other systems that may be triggered by this action and include their costs and/or benefits in the analysis.
- Identify costs and benefits for each of the steps and for the overall action plan.
- Identify a specific individual manager to be the sponsor of the plan (including the normal people responsible and the group involved in its execution). This is essential for motivation and commitment.

The plan should be developed for manager-level review, because the manager is responsible for ensuring that the action plan is effectively implemented. The specific steps, however, must be implemented at the level where the change
should take place. To ensure this, those individuals responsible for effecting the change must agree that the steps are reasonable and achievable.

For each step in the action plan, sub-action plans may be called for. The applications chapters do not identify sub-action plans. The process for developing these plans, however, is the same as for the major steps in the action plans.

Case study examples presented in this manual follow a general format for the action plan. This is only one of several ways to develop the action plans. Any approach that lays out the general framework is acceptable, as long as it is practical for the user and is understood by management.

The action plan must be simple and understandable; otherwise, its benefits will not be achieved. The action plan's degree of sophistication should be tailored to the utility and to the problems it faces.

DEVELOPING REPORTING DOCUMENTS TO (1) MONITOR THE COST-EFFECTIVE IMPROVEMENT PLANS AND (2) PROVIDE MANAGEMENT WITH INFORMATION ESSENTIAL FOR MANAGING THE UTILITY'S OPERATIONS

Effective reporting documents must be produced that enable the utility

* to monitor the cost-effective improvement action plans, and
* to allow for revising the action plans so that they maintain their effectiveness; that is, that the benefits exceed by appropriate margins the costs of adopting the action plans.

Reporting documents should also be produced that facilitate regular review of the performance indicator data. This review should identify new areas of improvement and the need for renewed effort if gains are not maintained.

The two basic types of PI/MRS reporting documents are the Performance Indicator Reporting Document and the Action Plan Reporting Document. These should be produced on a regular short-term (usually monthly) basis to provide frequent management updates and on a longer-term (usually annual) basis to reflect progress toward annual targets. The reports should also be less detailed at higher management levels, so that each manager receives only the information necessary for review and decision making at his level.

Performance Indicator Reporting Document. This document is a management control document that reports information on all performance indicators for the current year. It forms the basis for ongoing review of the indicators and their associated targets. A utility should devise the

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1/ For some areas of the utility where the costs are significant and changes are occurring on almost a continuous basis, such documents might be useful when produced more frequently than on a monthly basis.
Performance Indicator Reporting Document to meet its particular needs. Exhibit II-2 provides an example of such a reporting document—it reflects the important aspects that are part of any utility-specific document. These aspects are:

* Current Reporting Information - This compares the current operating level to the target defined in the action plans. The current reporting information also identifies acceptable deviations from targets, actual deviations, exception reports, and the net gain or loss in costs and benefits resulting from the deviations. This ensures both management control and a focus on cost effectiveness. For many indicators, targets differing from the existing level may not be set, because the operating level may be perceived to be at the most cost-effective level. These indicators are also shown to facilitate their continued review, ensuring that they are in fact at the most cost-effective level.

* Year-End Reporting Information - This information is similar to the current reporting information, except that only year-end information is presented. 1/

Action Plan Reporting Document. This document tracks the progress of the action plans. Exhibit II-3 provides an example of an Action Plan Reporting Document that includes the important aspects which should be part of any utility's specific document. These aspects are:

* Description of Action Plan - A brief summary for reference purposes.

* Initial Estimates - A list for comparing subsequent data.

* Update of Current Status - This shows current performance in relation to planned performance and acceptable deviations. Any indicated need for exception reports is also noted. If the current difference exceeds acceptable deviation, an exception report must be produced.

* Revised Long-Term Estimate - Based on the current status of the action plan, it may be necessary to revise the long-term estimates in the action plan. This is an important planning step because it recognizes that changes do occur during implementation. Rather than dwell on historical problems that may have developed in the initial stages of implementation, new

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1/ Many utilities find that reporting historical information on a graph is very useful. The graph could plot the monthly figures as well as the twelve month rolling average. Again, a utility should devise the document for its particular needs.
targets and revised action plans should be developed. The need for an exception report is also identified.

- Action Plan Priorities and Presentation for Management - The Action Plan Reporting Document is organized so that managers understand what areas require improvements. Action plan priorities—established by net benefits—should be included on the reporting document so that managers can concentrate their efforts on plans offering greatest potential improvements. Action plan #1 would therefore be the plan that promises the greatest returns relative to costs of gaining them (Rate of Return).

INTEGRATING THE PI/MRS PROCESS WITH THE PLANNING AND BUDGETING CYCLE TO PROVIDE INCENTIVE FOR FULL ACHIEVEMENT OF COST-EFFECTIVE IMPROVEMENTS

The PI/MRS fits logically into the annual planning and budgeting cycles. A suggested sequence for doing this is:

- To review all performance indicators during the planning and budgeting cycle to identify desired performance levels. The analysis can be simple or detailed. The key factor, however, is to look at every performance indicator in the planning and budgeting process to identify possible cost economies and efficiency improvements.

- To develop action plans (provided the review during the planning and budgeting cycle demonstrates that improvement is possible and justified), that will include targets and estimated costs and benefits for the upcoming budget year. These targets and estimated costs and benefits should then be integrated into the planning and budgeting process and should also be added to reporting documents so that they become specific budget items that management can monitor.

By ensuring that all of the performance indicators are reviewed at least in the planning and budgeting process, a utility can emphasize the need for improvement at a critical time in the year. The action plans developed in the planning and budgeting process should generally follow the PI/MRS process outlined previously. If time constraints preclude a full analysis, however, the action plan should be termed an initial action plan, with the understanding that a formalized action plan will be developed at a specified later date.

The cost and benefit estimates should be incorporated into the budget. This lends full corporate authority and makes employees accountable for their responses. The process can also help utility personnel to develop

1/ In addition to concentrating on these improvement efforts, managers would, of course, be responsible for normal day-to-day activities and should be constantly alert to additional improvement possibilities.
realistic budgets based on actual expectations rather than on mere extrapolations of the previous year's experience.

Targets, specific steps, and net benefits established for the action plans should be reported on the documents described in the previous sections. As managers gain experience working with the action plans, replanning can be incorporated, permitting appropriate revisions to the action plans. These revisions should be included as updates on both reporting documents. 1/ Also, any cost-benefit revisions should be made part of the budget reporting system to ensure that the utility has up-to-date financial information available.

Although we have stressed integration of the PI/MRS process with the planning and budgeting cycle, continuing analysis of the performance indicators should be performed and should be communicated to those concerned with them. This will ensure that improvements are identified throughout the year.

INTEGRATING THE PI/MRS PROCESS INTO THE HUMAN RESOURCE ASPECTS OF THE UTILITY

Employees throughout the utility will be responsible for implementing the action plans derived from the PI/MRS process. These employees must therefore receive information and be consulted in its interpretation. This is especially true for non-management personnel.

The human resource aspects of the PI/MRS process are:

- Employee understanding of PI/MRS process
- A participatory management approach
- Performance evaluation
- Rewards
- Clear communication from upper management
- Training designed to support the action plans

Employee Understanding of PI/MRS Process. Any management process, whether new or existing, must be understood by those involved in its execution and must be perceived to be a benefit to them. If employees are represented by organized labor, union officers must be fully educated in the PI/MRS process. Employees will make an effort to ensure maximum benefits of the process only when they fully understand it. Furthermore, PI/MRS objectives must be described clearly so that both upper and lower management are familiar with its objectives. One way to encourage understanding of the system is to

1/ Although targets and estimates are revised, the manager's progress towards the original target should be monitored to enable management to evaluate a manager's planning performance more effectively.
conduct training courses (open to management and non-management employees) in the use of the process.

**Participatory Management Approach.** The PI/MRS is structured as a top-down management approach, under which senior management (1) sets corporate and operating objectives and (2) works with middle management to identify performance indicators that measure these objectives. The identification of cost-effective improvements, as well as identification of performance indicator targets, however, works most effectively when the process is initiated by lower management or non-management levels and works its way up (within certain limitations) in a bottom-up approach. The participation of all affected personnel in devising the action plans is highly recommended because this more effectively motivates employees to do a good job when they own the process and are committed to it. For example, lower-level employees identify improvements and set targets. They then pass these to the next higher level of supervision or management for approval or revision. Experience shows that the improvement targets prompted by employees in a participatory process will often be higher and better defined (and more achievable) than when supervisors and upper management dictate the targets. This manual does not attempt to repeat the exhaustive and documented research on the benefits of a participatory management approach, but simply points out the potential advantages of the approach in achieving full benefits of the PI/MRS process.

**Performance Evaluation.** Performance evaluations are used to reinforce proper use of the PI/MRS process. Management and non-management performance evaluations are linked to achieving performance targets over which the individual has control. The links must be established carefully and precisely, so that employees do not feel that their performance evaluation is based only on figures accumulated. If done correctly, such links help keep personal biases from entering into the evaluation process. Performance evaluations linked to appropriate performance indicators and targets will help employees understand that achieving targets will result in more favorable evaluations, encouraging work that promotes the overall objectives of the utility.

**Rewards.** It is important for employees to receive recognition when they have achieved personal objectives measured in the performance evaluations. The form of the recognition must be based on the utility's particular social culture and business environment and depend on the nature and magnitude of the utility's benefit from employee performance.

**Clear Communication from Upper Management.** Upper management must ensure that all employees fully understand the importance of cost economy by clearly and consistently reminding employees of the value of cost economy. Further, upper management must communicate overall objectives to employees and point out that these objectives are fostered through the PI/MRS process.

**Training Designed to Support the Action Plans.** Initial employee training in the PI/MRS process should be followed by periodic reviews to reinforce initial training. Based on these reviews, supplementary training should be given as necessary.
CRITICAL INDICATORS FOR GENERATION, TRANSMISSION AND DISTRIBUTION, AND COMMERCIAL OPERATIONS

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1. System equivalent forced outage rate</td>
<td>1. Number of T&amp;D circuit trip-outs by voltage level per 100 circuit km, and number of transformer failures per 100 transformers on system (by class)</td>
<td>1. Billing lag</td>
</tr>
<tr>
<td>2. System percentage reserve at peak</td>
<td>2. Total unserved energy (MWh) caused by total T&amp;D failures/total energy generated</td>
<td>2. Energy theft</td>
</tr>
<tr>
<td>4. System output factor</td>
<td>4. Total full-time equivalent T&amp;D staffing years/total energy generated</td>
<td>4. Bad debt/total revenues</td>
</tr>
<tr>
<td>5. System annual average heat rate</td>
<td>5. System output factor</td>
<td>5. Inventory turnover</td>
</tr>
<tr>
<td>6. System percentage difference between actual net dependable capability and design net dependable capability</td>
<td>6. Dispatch performance</td>
<td></td>
</tr>
<tr>
<td>7. Net interchange value/total revenues</td>
<td>7. Number of occurrences in which limited transmission outlets constrained economical generation</td>
<td></td>
</tr>
<tr>
<td>8. System fuel cost/thermal kWh generated</td>
<td>8. Net interchange which limited transmission outlets constrained economical generation</td>
<td></td>
</tr>
<tr>
<td>9. Total system cost of energy delivered/kWh sold</td>
<td>9. Total full-time equivalent generation staffing years/system MW</td>
<td></td>
</tr>
<tr>
<td>10. Total system cost of energy delivered/kWh sold</td>
<td>10. Total full-time equivalent generation staffing years/system MW</td>
<td></td>
</tr>
<tr>
<td>11. Total full-time equivalent generation staffing years/system MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
PERFORMANCE INDICATOR REPORTING DOCUMENT

Date: ______________________
Department: ______________________

<table>
<thead>
<tr>
<th>Performance indicator #1</th>
<th>Performance indicator #2</th>
<th>Performance indicator #3 etc.</th>
</tr>
</thead>
</table>

I. Current reporting information

Current operating level
Current target
Acceptable deviation
Actual deviation
Exception report needed
Gain (loss) in net benefits for period

II. Year end reporting information

Originally planned target
Acceptable deviation
Revised targets
Exception report needed
Gain (loss) in net benefits for period
## ACTION PLAN REPORTING DOCUMENT

<table>
<thead>
<tr>
<th>Date:</th>
<th>Department:</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Action plan #1</th>
<th>Action plan #2</th>
<th>Action plan #3, etc.</th>
</tr>
</thead>
</table>

### I. Description of action plan

### II. Initial estimates

<table>
<thead>
<tr>
<th>Targets</th>
<th>Annual net benefits</th>
</tr>
</thead>
</table>

### III. Update of current status

<table>
<thead>
<tr>
<th>Target</th>
<th>Current planned</th>
<th>Acceptable deviation</th>
<th>Current actual</th>
<th>Current difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated net benefits</td>
<td>Current planned</td>
<td>Current actual</td>
<td>Current difference</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Exception report needed</th>
<th></th>
</tr>
</thead>
</table>

### IV. Revised long-term estimate

<table>
<thead>
<tr>
<th>Target</th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual net benefits</td>
<td>Long-term originally planned</td>
<td>Acceptable deviation</td>
<td>Long-term now expected</td>
</tr>
<tr>
<td></td>
<td>Long-term difference</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Revised actual plan necessary</td>
<td>Yes/No</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Exception report needed</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

This appendix describes the steps identified in Chapter II for building the Performance Indicator Data Base.

IDENTIFYING THE DATA NEEDED TO COMPUTE THE SELECTED PERFORMANCE INDICATORS

Once specific performance indicators have been identified, data needed to compute the indicators must be identified. If the indicators are drawn from the menu of performance indicators presented in the applications chapters (III through V), it is necessary only to refer to those chapters to identify data needed to compute the selected performance indicators. If the indicators are drawn from other sources, specific analyses should be performed to identify the data.

Determining Whether Data Are Available. The next step is to review existing records and reporting systems to determine if the data identified in the previous step are available. This step should provide an item-by-item analysis of data availability.

Determining the Cost Effectiveness of Collecting Data Not Currently Available. In all likelihood, not all the needed data will be available. The cost to collect unavailable data should be determined and be compared with the benefits of having the data.

Determining a Preliminary Set of Useful Indicators. The previous steps will yield a preliminary set of useful indicators.

Reviewing the Preliminary Set of Useful Indicators and Determining Whether Additional Indicators Should Be Considered. The preliminary set of useful indicators should be reviewed to determine if it is sufficient for the utility's needs. If the list is not sufficient, requisite additional indicators should be added and treated as before.

Determining the Final Set of Useful Indicators and Designing the Collection Process (Either Mechanized or Manual) To Develop a Data Base of Indicators That Can Be Analyzed and Can Be Collected and Forwarded with Little Delay to Meet Reporting Requirements. The previous step establishes a useful set of indicators. A system must be designed for this set of indicators that (1) contains the historical performance indicator data and produces a live data base by continually adding the most recent data for use in later analysis and (2) generates the current performance indicator data and

---

1/ The data base, because it will be used for analysis, should be as complete as possible. It should be updated in the same manner as the reporting documents. The data base is more fully discussed in the final step of this appendix.
forwards it to a central collection point, while the data are fresh. At the central collection point the data are tied into the requirements of the reporting documents identified in Chapter II. This process can be mechanized or manual, but proper design of the system is critical to ensure that the reported information is fresh, accurate, and usable for management purposes. The resources required to complete this step may limit the utility's ability to implement a comprehensive, utility-wise PI/MRS. In this event, a limited scope PI/MRS can first be installed.

Field Testing the Procedures To Ensure That the Data Base Serves Its Purpose As Intended on a Regular Basis. This step is undertaken after the system is fully designed.

Organizing Data Base Information for Analysis. As noted in Chapter II, the historical data bases are used in an analysis that identifies potential cost effective improvements. To facilitate this analysis, data should be organized to permit effective review. Since the data will, in some cases, be compared with other utility data, data should also be grouped appropriately and statistical information should be provided so that external changes affecting the performance indicator can be monitored. Examples of the types of schedules, groupings, and statistical data needed for a typical data base are provided in the international data base of worldwide utilities compiled by Ernst & Whinney and presented in each of the subsequent chapters.
CHAPTER III
APPLICATION TO GENERATION ACTIVITIES
OF THE PI/MRS PROCESS

INTRODUCTION

This chapter discusses how the PI/MRS process is applied to the generation activities of an electric utility and provides examples—using a hypothetical utility—to illustrate this application. 1/

Generation activities include all of the operating and maintenance (O&M) functions, power plant dispatching, and fuel supply. Energy sources considered include steam plants (coal, gas, and oil), diesel, combustion turbines (gas and oil), and hydro. 2/ It is assumed that each of the power plants, the dispatching function, and the fuel supply function is headed by a manager in the hypothetical utility and that these managers report to the generation general manager. The generation general manager reports to the chief executive, who is the utility's chief executive officer.

Power plant operation is the responsibility of the power plant manager who is typically responsible for a single power plant that includes several units of various types. A plant manager may head several plants, however, when these facilities are relatively old or small. Duties within each plant are usually divided into those dealing with operations and with maintenance, a manager of each area reporting to the power plant manager.

Dispatching of the generation units—the second responsibility area within the generation function—involves unit commitment, unit loading, and interchange opportunities. This is usually headed by a system operations manager.

Fuel supply—the third responsibility area within the generation function—includes transportation, fuel inventory, procurement, monitoring, and other related areas. This area is usually headed by a fuel supply manager. 3/

1/ Although this chapter can stand alone, generation personnel may want to read the other two applications chapters (IV and V) of this manual to understand how the PI/MRS process is applied to other major functions of a utility.

2/ As noted in Chapter II, this manual will not discuss the planning activities related to these areas. Nor does this chapter discuss the function of transmission and distribution of power to the customer load.

3/ To permit greater control, many utilities ensure a separation of fuel supply and operations by having the fuel supply manager report to a position other than the generation general manager. The discussion in this manual, however, assumes that the fuel supply manager does report to the generation general manager.
This chapter is particularly important because fuel costs often account for 50% to 70% of a utility's total annual operating costs, while generation operating and maintenance activities and system operation functions often account for 12.5% to 17.5% of the utility's annual operating costs (i.e. 25% to 35% of utility's non-fuel operating budget). 1/ These costs must therefore be tightly controlled to help ensure the utility's overall cost effectiveness.

Performance indicators assist in measuring the extent to which the objectives of generation activities have been achieved. This manual assumes that the overall objective of generation activities is to "perform the generation functions in a way that enables the utility to provide safe and reliable electricity at minimum cost". On an operating level, the following objectives support this overall aim.

**Generation O&M**

* Provide sufficient generation to meet load.
* Provide reliable power and energy.
* Provide cost-effective power.

**System Operations**

* Provide cost-effective use of system capability.

**Fuel Supply**

* Provide reliable supply of fuel.
* Provide appropriate fuel quality to meet plant fuel specifications and environmental quality constraints.
* Provide fuel at cost-effective price.

The remainder of this chapter is divided into six sections that correspond to the six elements of the PI/MRS process described in Chapter II:

1/ Table II-1 on page 14 illustrates these figures.
Identifying useful staffing and operational performance indicators.

Developing the performance indicator data base and reporting requirements.

Identifying possible cost-effective improvement tasks and developing action plans to achieve them.

Developing reporting documents to (1) monitor the cost-effective improvement plans and (2) provide management with information essential for managing the utility's operations.

Integrating the PI/MRS process with the planning and budgeting cycle to provide incentive for full achievement of cost-effective improvements.

Integrating the PI/MRS process into the human resource aspects of the utility.

IDENTIFYING USEFUL STAFFING AND OPERATIONAL PERFORMANCE INDICATORS FOR GENERATION ACTIVITIES

Manager-level Performance Indicators. Annexes III-1, III-2, and III-3 present appropriate indicators that can be used at the manager level to evaluate generation O&M, dispatching, and fuel supply activities. These indicators are applicable for all types of generation equipment and the related fuel sources.

Exhibits III-1, III-2, and III-3 provide the following information about each of these indicators and are to be found immediately following the annexes:

- How the performance indicator assists in measuring the achievement of objectives.

- Why the performance indicator is important. This includes a discussion of what the performance indicator measures, how the performance measures are calculated, and the level to which the performance indicator should be addressed.

Appendix III-A provides additional discussion of each of these three exhibits.

To ensure that the utility's overall objectives are achieved, performance indicators should be identified for all levels of the utility.

Chief Executive Performance Indicators. The chief executive is primarily concerned with generation activities that have a major cost impact on the utility. Because fuel can account for 50% to 60% of the utility's
budget and the cost of producing power--exclusive of fuel--is often 12.5% to 17.5% of total utility expenses, this area demands attention of the chief executive. Such attention is encouraged through use of the performance indicators identified in Annex III-4. Because these indicators are so important, they are termed critical performance indicators. These indicators are a subset of the generation general manager's indicators.

**Generation General Manager Performance Indicators.** To measure the overall effectiveness of generation activities, the generation general manager needs a comprehensive set of performance indicators such as:

- Station and system information about each of the performance measures concerning generation O&M activities tracked by the individual plant managers.
- The same information as the systems operation manager, because these indicators reflect important system-wide considerations.
- A subset of the fuel supply manager's indicators that track the most critical measures.
- Some overall measures not reflected in any of the individual manager's indicators.
- Finally, information on any major changes and variances in any of his managers' performance areas. These changes, discussed in a later section, are usually reported in an exception report.

The generation general manager's indicators are listed in Annex III-5.

**DEVELOPING THE PERFORMANCE INDICATOR DATA BASE AND REPORTING REQUIREMENTS**

The generic discussion in Chapter II is applied to generation activities in Exhibits III-1, III-2, and III-3--which detail the type of data needed to compute the generation function's performance indicators.

**IDENTIFYING POSSIBLE COST-EFFECTIVE IMPROVEMENTS AND DEVELOPING ACTION PLANS TO ACHIEVE THEM**

The case studies presented in Appendix III-C illustrate how this element is applied to the generation function.  

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1/ The case studies are intended only to demonstrate the PI/MRS process--they do not present the detailed, comprehensive analysis that would be part of a utility's actual PI/MRS activities.
indicators—system heat rate, dispatch performance, and net value of interchange, 1/—have been chosen to show how the three steps involved in this element would be performed. Dispatch performance and net value of interchange are presented in a single case study because they are so closely related.

The case studies assume various figures and operating conditions for the hypothetical utility to demonstrate more effectively how the PI/MRS process can be used to identify and achieve cost economies. The assumptions (as well as the analysis of the figures in the PI/MRS process) are based on experience with several power utilities.

In order to permit the method of analysis that uses comparative figures from other utilities, Appendix III-D presents the results of Ernst & Whinney's survey of U.S. and international utilities. This survey identified the following generation performance indicators: annual heat rate, availability factor, equivalent availability factor, forced outage rate, output factor, generation employees per MW of system capacity, and percentage reserve. To reflect the actual operating experience of utilities in the comparative figures used in the case studies, figures obtained from actual utility performance are used. As noted in Chapter II, however, comparative performance indicators must be used with care; so the Chapter II discussion of comparative indicators should be read carefully before proceeding with the case study examples.

DEVELOPING REPORTING DOCUMENTS TO

(1) MONITOR THE COST-ECONOMY AND EFFICIENCY-IMPROVEMENT PLANS AND
(2) PROVIDE MANAGEMENT WITH INFORMATION ESSENTIAL FOR MANAGING
UTILITY OPERATIONS

To show how this element is applied to generation activities, the heat rate case study for Unit C in Appendix III-C will be used as an example. The case study is presented by month to show how reporting documents are developed.

Month One, Year One. At this time the hypothetical utility is preparing annual plans and budgets. During the previous year, the utility identified an opportunity for improving Unit C's heat rate, and proceeded to conduct Phase I and the first step of Phase II of the action plan discussed in the case study in Appendix III-C. Installation of the cyclonic separator has begun, and the utility has established the following budget targets:

* Improve heat rate by 38 kcal/kWh (2,597 to 2,559) by installing the cyclonic separator.

1/ Appendix III-B provides additional information (but not case studies) to assist in applying the PI/MRS process to the other critical generation performance indicators.
Realize initial costs of $75,000 and annual net benefits of $110,000, starting in year two.

This information is incorporated into the annual budget (initial cost of $75,000).

Month Two, Year One. Heat rate improvement is not expected during year one because cyclonic separator installation requires a full year. The unit's heat rate would be monitored, however, to ensure that the measurement does not worsen (see Exhibit III-4).

The utility's project management system should track cyclonic separator installation. The Performance Indicator Reporting Document can also be used, however, to provide installation progress reports for the generation general manager. Project management status is boxed in dotted lines (in Exhibit III-4) to emphasize that this information is an added part of the reporting document. The status indicates that the project will be completed on time.

Remaining Months of Year One. Cyclonic separator installation is completed in Month 12, Year One. Thus, the first month in which new, current data would be produced for the action plan reporting document would be Month Two, Year Two.

Month Two, Year Two. Exhibit III-5 shows the Action Plan Reporting Document for this period. A description of the figures follow:

- Update of Current Status - The current operating level is 2,572 kcal/kWh. A 25 kcal/kWh improvement has been achieved during month one. The current target, however, is 2,559 kcal/kWh and the established acceptable deviation is 6 kcal/kWh. The actual deviation of 13 kcal/kWh therefore triggers an exception report. The loss in net benefits for the period (1/12 of a year) is estimated to be 13 kcal/kWh, or $3,000 (13/38 x 1/12 x $110,000).

- Revised Long-Term Estimate - Although the target for month 2 is not achieved, the hypothetical utility's analysts believe that the action plan should be changed so that the company still meets its monthly target. This requires an exception report. An annual loss of $3,000 is still incurred for month 2.

This information should be included in a report that incorporates information from all action plans produced by the managers reporting to the generation general manager.
INTEGRATING THE PI/MRS PROCESS WITH THE PLANNING AND BUDGETING CYCLE TO PROVIDE INCENTIVE FOR FULL ACHIEVEMENT OF COST EFFECTIVE IMPROVEMENTS

The generic discussion in Chapter II and the case study of reporting documents provide the necessary information to apply this element to generation operations. Important aspects of this element are:

- The PI/MRS process can make the planning and budgeting cycle a useful exercise for promoting cost economies and efficiency improvements.
- All performance indicators should be reviewed in the planning and budgeting cycle.
- Annual cost revisions noted on the performance indicator reporting document should be used in preparing the annual budget.
- Continuing reviews should be undertaken to focus on future cost savings.

INTEGRATING THE PI/MRS PROCESS INTO THE HUMAN RESOURCE ASPECTS OF THE UTILITY

The generic discussion of this element in Chapter II is sufficient for applying this element to generation activities.
### MENU OF GENERATION O&M PERFORMANCE INDICATORS
FOR USE AT PLANT MANAGER LEVEL

#### Operations

**Objective:** Provide Sufficient Generation to Meet Load

1. MWh lost due to operator-caused outage *
2. Output at each monthly peak *
3. Spinning reserves at each monthly peak
4. Available capacity at each monthly peak
5. Unavailable capacity at each monthly peak

#### Maintenance

**Objective:** Provide Reliable Service

8. Equivalent availability *
9. Percentage difference between actual net dependable capacity and design net dependable capability *
10. Capacity factor *
11. Output factor *
12. Equivalent forced outage rate *
13. Planned outage rate *
14. Actual maintenance man-hours *
15. Actual maintenance man-hours **
16. MWh lost due to specific major components 1/ *
17. Estimated man-hours of maintenance backlog **

** By unit
** By plant

---

1/ Typical major generation components: turbine (also control valves), generator/exciter, boiler tubes (leaks, slagging, soot blowing, washing), water treatment (makeup, deaeration, heating), cooling water (condenser, valves, screens), fly ash collection (cyclones, precipitators), bottom ash collection (wet bottom, clinker grinders, piping), ash disposal, fuel handling (stacking, reclaiming, transporting, pulverizing), fuel burning, air handling (induced and forced draft fans, air preheating).
<table>
<thead>
<tr>
<th>Operations</th>
<th>Maintenance</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Objective:</strong> Provide Cost-Effective Power</td>
<td><strong>Expected life of specified components</strong></td>
</tr>
<tr>
<td>18. Average heat rate *</td>
<td>22. Age of major components replaced in six years *</td>
</tr>
<tr>
<td>19. Hydro unit throughput factor *</td>
<td>23. Maintenance utilization % (actual hours vs. estimated hours)**</td>
</tr>
<tr>
<td>20. FTEs 1/ (by category) generation</td>
<td>24. Generation maintenance staff numbers / **</td>
</tr>
<tr>
<td>operation staffing years ** MW</td>
<td>MW installed</td>
</tr>
<tr>
<td>21. Total operations cost ** MWh generated</td>
<td>25. Total maintenance cost ** MWh generated</td>
</tr>
<tr>
<td>26. Change in average heat rate since last major overhaul *</td>
<td></td>
</tr>
</tbody>
</table>

* By unit
** By plant

1/ Full-time equivalent employees categorized by the following categories, if possible: supervisory, skilled operations, skilled maintenance, administrative, fuel handling, and unskilled.
### MENU OF SYSTEM OPERATIONS PERFORMANCE INDICATORS FOR USE AT MANAGER LEVEL

**Objective:** Cost effective use of system capability

<table>
<thead>
<tr>
<th>Unit</th>
<th>1. Dispatch Performance Ratio 2/</th>
<th>2. Interchange Purchase Cost</th>
<th>Equivalent Internal Generation Cost</th>
<th>3. Equivalent Internal Generation Cost</th>
<th>Interchange Sales Cost</th>
<th>4. Interchange Purchases (MWh) * 100</th>
<th>Total MWh Generated</th>
<th>5. Interchange Sales (MWh) * 100</th>
<th>Total MWh Generated</th>
</tr>
</thead>
<tbody>
<tr>
<td>#</td>
<td></td>
<td>#</td>
<td></td>
<td>#</td>
<td></td>
<td>$</td>
<td></td>
<td>$</td>
<td></td>
</tr>
</tbody>
</table>

---

1/ This menu provides indicators for interchange performance. Although interchange does not currently play a major role in many countries, interchange with major industries, between utilities and across international borders may eventually become more important as costs continue to rise.

2/ This indicator is calculated by dividing the fuel costs associated with the current dispatching operations by the fuel costs that would be incurred under the most cost-effective dispatching operation.
### MENU OF FUEL SUPPLY PERFORMANCE INDICATORS FOR USE AT MANAGER LEVEL

**Objective:** Provide reliable source of fuel 1/

<table>
<thead>
<tr>
<th></th>
<th></th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>System unserved energy (MWh) caused by shortages of fuel supply</td>
<td>100 % MWh generated for the system</td>
</tr>
<tr>
<td>2.</td>
<td>MWh of restricted plant operations (full and partial) caused by lack of fuel</td>
<td>100 % 8,760 MW capacity of plant</td>
</tr>
<tr>
<td>3.</td>
<td>Annual short-term vs. long-term fuel under contract</td>
<td>%</td>
</tr>
<tr>
<td>4.</td>
<td>Annual amount of shortfalls and overages</td>
<td>100 % Total fuel delivered (by vendor) under long-term contracts</td>
</tr>
</tbody>
</table>

**Objective:** Provide fuel of appropriate quality to meet plant fuel specifications and environmental quality constraints

<table>
<thead>
<tr>
<th></th>
<th></th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.</td>
<td>MWh restricted plant operations (full and partial) caused by non-conformance with environmental quality constraints</td>
<td>100 % 8,760 MW capacity of plant</td>
</tr>
<tr>
<td>6.</td>
<td>MWh restricted plant operations (full and partial) caused by non-conformance with plant fuel specifications</td>
<td>100 % 8,760 MW capacity of plant</td>
</tr>
<tr>
<td>7.</td>
<td>Amount of fuel not conforming to contractual requirements</td>
<td>% Total fuel delivered 2/</td>
</tr>
<tr>
<td>8.</td>
<td>Amount of oil required for flame stabilization in solid fuel plants</td>
<td>kg/MWh MWh generated</td>
</tr>
</tbody>
</table>

1/ All indicators should be by fuel type and plant, if possible.

2/ This should be done for all important quality contractual specifications such as sulfur, ash, etc.
Objective: Provide fuel at cost-effective price

9. Transportation costs . 100
   Total delivered fuel cost

10. Demurrage costs . 100
    Total delivered fuel cost

11. Total cost of delivered fuel
    kWh generated
    $/kWh

12. Fuel costs . 100
    Total utility revenues

13. Minimum and maximum plant inventory level (in each month) during the year converted to days of burn at full output
    days

14. Annual average plant inventory level converted to days of burn at full output
    days

15. Actual turnover of fuel inventory
    $ (Value)

16. Average cost of fuel in inventory . 100
    Annual fuel costs
    $

17. Price of spot fuel/Price of long-term fuel
    $

18. Incremental costs of additional fuel procured to meet shortfalls . 100
    Total fuel costs
    $

1/ All indicators should be by fuel type and plant, if possible.

2/ This should be done for all important quality contractual specifications such as sulfur, ash, etc.
Objective: Ensure that the utility is achieving its overall goals and objectives by providing guidance in those generation areas having major impact on utility

1. System equivalent forced outage rate.  
2. System percentage reserve at peak.  
3. System equivalent availability.  
4. System output factor.  
5. System annual average heat rate.  
6. System percentage difference between actual net dependable capability and design net dependable capability.  
8. Net interchange value/total revenues.  
10. Total system cost of energy delivered/kWh sold in system.  
11. Total full-time equivalent generation staffing years/system MW.  
12. Aggregate indicators for entire utility that include the generation function.

Objective: Overall management control of utility

1. Listing of all major changes and variances in any of the generation general manager performance measures.  

---

1/ The chief executive will also receive aggregate information on staffing years per customer, overall O&M cost per kWh, and other aggregate indicators.

2/ Including measurement against certain targets, discussed later in this chapter.
GENERATION GENERAL MANAGER
PERFORMANCE INDICATORS 1/

Objective: Generation O&M
1. Summary by plant and by system of all individual power plant manager performance indicators.

Objective: System operations
1. Same indicators as for system operating manager.

Objective: Fuel supply
1. System unserved energy (MWh) caused by shortage of fuel per MWh generated for the system.
2. MWh of restricted operations (full and partial) caused by lack of fuel.
   \[ \frac{100}{8,760 \times \text{MW capacity of plant}} \]
3. Total delivered fuel cost per kWh generated.
4. Actual average turnover of fuel inventory in period of measurement.
5. Fuel cost/total utility revenues in period of measurement.

Management control of all generation activities
1. Unserved energy (MWh) caused by shortages of generating capacity.
2. Generation total non-fuel costs per kWh sold.
3. Generation cost of energy produced per kWh sold.
4. Value of interchange per kWh sold: distinguish for net purchase and net sales.
5. Total cost of energy delivered per kWh sold.
6. Listing of all major changes and variances in any of the performance measures monitored by managers in the generation function. 2/

---

1/ By plant and system, where applicable.
2/ Including measurement against certain targets, discussed later in this chapter.
GENERATION O&M PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide sufficient generation to meet load

Operations Performance Indicators

III.1.1. MWh lost due to operator caused outage * 100

MWh generated *

This indicator shows the percentage energy lost due to operator error—one of the causes of both full and partial outages. This error usually results from inexperience or lack of knowledge. Recording operator-caused unit outages or reductions by MWh, provides one measure for evaluating operator effectiveness. It also serves to target training requirements. The source of data for this indicator is an outage-cause analysis log. The cause of each unit trip or deration should be entered. This log should be kept by the senior shift operator and reviewed by the plant manager. Only those outages caused by operator error should be used as part of this indicator. The performance measure is calculated by adding all MWh of operator-caused outage. This is reported by month and year-to-date.

III.1.2. Output (MW) __________________________________________

Name-plate rating at each monthly peak (MW) *

This indicator shows how well each unit performed when it was needed. Its usefulness is limited if the entire capability of the unit is not needed to meet the monthly peak load. By tracking each monthly peak instead of the single annual peak, the indicator is more precise. The unit output at each monthly system load peak hour should be divided by the unit's name-plate rating. The resulting indicator shows how well the unit performed. The source of this data is the system dispatch log, which will contain data on monthly peaks as well as unit output.

III.1.3. Spinning reserves (MW) * 100

System peak load at each monthly peak

This indicator provides a measure of system security. It should be assembled by system. Spinning reserves are reserves synchronized with the system and can be used to respond quickly to load increases. Sufficient spinning reserves should at least be available to cover the loss of the target unit or tie line import flow. By observing spinning reserves on a monthly basis, additional points are recorded. The system dispatch logs will have hourly peak and spinning reserve data.

III.1.4. Available capacity * 100

System peak load at each monthly peak

This indicator shows the total available capacity percentage related to the load monthly peak. Available capacity is generation capacity that was either on line or unloaded or was off line but available for start-up. While there are logical reasons for unavailable capacity—such as planned outages—monthly system peak loads must be met. System dispatch logs should contain available generation capacity data.

* By unit
** By plant
111.1.5. Unavailable capacity (MW) . 100

System peak load at each monthly peak (MW)

This provides a monthly measure of unavailable capacity amounts as a percentage of total system load. This should fluctuate widely. Unavailable capacity is generation capability that is off due to a forced or planned outage, and is therefore not available to meet load. During lower load periods, when maintenance is scheduled, the percentage can be quite high. The source of this data is also the system dispatch logs.

**Maintenance Performance Indicators**

111.1.6. Equivalent forced outage rate at monthly peak *

\[
\text{By unit} \quad \frac{\sum (\text{Unit rating MW} \cdot \text{Outage hours})}{\text{Installed capacity (MW)} \cdot \text{Hours in period}} \cdot 100
\]

This indicator includes both full and partial forced outages, which makes it a good indicator of the unit's inability to operate at the point in the month when the unit is most needed. While some forced outages are the result of operator error (as discussed in a previous indicator), many such outages are the result of insufficient maintenance. A consistently high forced outage rate should be examined to discover specific causes, with additional maintenance applied in problem areas. The source of this data is the system dispatch logs. All MWh of forced outage occurring during the monthly peak should be added. This total is then divided by the total installed system generating capacity multiplied by the period (hours) to yield the equivalent forced outage rate.

111.1.7. MW Capability lost due to specific major components at time of peak . 100

Planned output at time of peak (MW)

This indicator identifies the specific causes of lost capability due to component outages. The major components considered here are listed in Table III-1. Each of these components can contribute to lost capability, so each should be tracked separately as well as in combination. The capacity lost due to these components at peak should be compared to forecast system peak load so that the maintenance planners will know which portion of maintenance problems are caused by major components and, of these, which individual components were the highest contributors. Plant machinery history and operator logs are the source of the component outage information.

* By unit
** By plant
III.1.8. Equivalent availability *

\[ \text{Equivalent availability} = \frac{\text{MWh Generated by unit in period}}{\text{MW Rating of unit} \times \text{Hours in period}} \times 100 \]

This indicator measures the availability of each unit after partial and full outages (both planned and forced) have been allocated. This indicator is also useful to determine whether sufficient capacity is available in the total system. Acceptable values for equivalent availability are in the 70% to 80% range, depending on the requirements of the system output factor. The system dispatch logs contain the data that provides an hourly capacity available from each generating unit. Each unit is calculated separately on a monthly and year-to-date basis by adding up all the available MWh and comparing this total as a ratio with the total power capacity of the specific unit times the number of hours in the period.

III.1.9. Percentage difference between actual net dependable capability and design net dependable capability *

\[ \text{Percentage difference} = \left( \frac{1}{x} \sum \left( \frac{\text{Unit load capability (MW) recorded hourly in period}}{\text{Design site rating (MW) of unit} \times \text{Hours in period}} \right) \right) \times 100 \]

This indicator provides a unit-by-unit measure of how well a unit is operating as compared with its design capability. The reasons for any shortcomings cannot be attributed solely to operations, but also must acknowledge deficiencies and maintenance problems. Variations can often be attributed to the way the unit is operated. Thus, the operator might be responsible for a unit not performing as well this month as last, provided there are no new maintenance problems. The data for this calculation are available in the plant operating logs. Net dependable capability should be recorded hourly, with these hourly MW amounts totaled for each month. This sum should be divided by the number of hours in the month. The resulting average hourly net dependable capacity should be divided by design net dependable capacity to express the difference as a ratio.

III.1.10. Output factor *

\[ \text{Output factor} = \frac{\text{MWh Generated by unit in period}}{\text{Site rating of unit (MW) \times Hours in period connected to system}} \times 100 \]

This indicator measures the extent to which each unit's capability is used. It serves as a guide to the relative value of each unit in meeting the system peak loads. The output factor should be highest for the most efficient and economical units and lowest for less economical units. Data for this calculation are available in the system operation logs. This calculation is based on the total unit MWh output in a period divided by the product of maximum dependable capability times the number of generation unit service hours in the period.

* By unit
** By plant
III.1.11. **Capacity factor**

\[
\text{Capacity factor}^* = \frac{\text{MWh Generated by unit during the period}}{\text{Site rating of unit (MW)} \times \text{Hours in period}} \times 100
\]

This indicator is often used as a substitute for the output factor discussed above. Capacity factor of a unit indicates the MWh output during a year, without considering service time. Thus, capacity factor does not allow any built-in allowance for planned or forced outages, and, therefore, provides a true description of how productive each unit was during the year. Capacity factors of units can be compared directly to determine where improvement potential lies. If the capacity factor of a unit approaches the limit of available output, then little improvement can be achieved. The same data is used for this indicator as for output factor above, except that total hours in the period are substituted for service hours.

**Maintenance Performance Indicators**

III.1.12. **Equivalent forced outage rate**

\[
\text{Equivalent forced outage rate}^* = \frac{\sum (\text{MW load reduction of unit caused by forced outage recorded hourly in period})}{\text{Site rating of unit (MW)} \times \text{Hours in period}} \times 100
\]

This shows the total forced outage component by unit, including both full and partial outages. As such, it is the best single indicator of maintenance effectiveness. A high equivalent forced outage rate in an efficient, economical unit should be corrected by allocating additional maintenance resources. This data is available in both the plant and operating logs and the system dispatch logs. All forced outage MW should be totaled by hour for each period (usually a month). This total should be divided by the product of total unit capability times the number of hours in the period.

III.1.13. **Planned outage rate**

\[
\text{Planned outage rate}^* = \frac{\sum (\text{MW load reduction of unit caused by planned outage recorded hourly in period})}{\text{Site rating of unit (MW)} \times \text{Hours in period}} \times 100
\]

This indicator measures the amount of planned outage by unit and is used to compare with the equivalent forced outage. The total unit equivalent availability should be in the 70% to 80% range; of the 20% to 30% unavailability 12% to 16% should be planned. The objective is to drive down the forced percentage by applying planned maintenance. Planned maintenance is less expensive than unplanned maintenance because it can be scheduled at the utility’s convenience and more can be accomplished with a lower displaced energy cost. This data is available in the plant operating logs and in the system dispatch logs. This indicator is calculated by adding all MW of planned outage (either full or partial) in each hour of the period. This total is divided by the product of total unit capability times the number of hours in the period.

* By unit
** By plant
III.1.14  Actual maintenance man-hours
Actual net dependable capability (MW) **

This indicator shows on a plant basis the number of maintenance man-hours required to maintain one megawatt of capacity. Plans can readily be compared to show relative maintenance effectiveness. Of course, plant age and fuel type must also be considered. This data is available in each plant by totaling all the maintenance man-hours from maintenance time reports for the period. The actual net dependable capability as derived for III.1.9 is used to calculate the indicator.

III.1.15.  Actual maintenance man-hours
MWh generated **

This provides the same sort of data as the previous indicator except that MWh of output is the basis for comparison. By using MWh, relative plant load is recognized. A plant with a high output factor will clearly have higher maintenance man-hours/MW of capacity than a similar plant with a low output factor. As such, it is a more valuable indicator of maintenance effectiveness than the previous indicator if used singularly, but the use of both indicators is valuable. Calculation of this indicator is quite similar to that for the preceding one except that total MWh of plant output during the period is divided into the total maintenance man-hours.

III.1.16.  MWh lost due to specific major components *
MWh generated *

This indicator provides another measure for indicating which components are the primary contributors to losing MWh of output. This uses the partial and full outage occurrences that can be attributed to major components and weighs them according to MWh of output by unit. Plant machinery history or plant operating logs are the source for the MWh lost due to each specific identified component during the period. The MWh loss attributable to each component is then divided by the total unit MWh output in that period. In the case of components common to more than one unit, such as the cooling water system, the total MWh output from all common units is used.

III.1.17.  Estimated man-hours of maintenance backlog
Average amount of work completed in one week **

This indicator shows the average weeks of work remaining for each plant, which can be readily compared with other plants. Depending on the relative size of the backlog, maintenance resources should be reallocated. This indicator requires a maintenance work-order system that uses man-hour estimates for each pending work item. The pending items should be categorized by type (regular maintenance that can be done any time or outage maintenance that requires either a full or partial outage for access to the component). For this indicator, the sum of the two types is used. The sum is compared to the recent average amount (man-hours) of maintenance work completed per week over, for example, three months at the plant.

* By unit
** By plant
Objective: Provide cost-effective power

Operations Performance Indicators

III.1.18. Average heat rate *

\[ \text{Average heat rate} = \frac{\text{Quantity of fuel used} \times \text{Net calorific value per unit quantity (kcal)}}{\text{MWh generated by unit} - \text{Station service (MWh) attributable to unit}} \]

This indicator measures the amount of energy (in kilocalories) needed to produce one net kWh (gross kWh minus station service). This should be calculated at least annually and preferably monthly for each unit. The greatest difficulty, particularly in coal-fired plants, is the accurate allocation of fuel to each unit. Care must be taken to calibrate fuel flow scales and meters so that the unit heat rates will be valid. This indicator is one of the most important, because it provides information about the efficiency of converting heat to kWh, which is the basic function of a power plant. The source of the required data is the plant operating logs. These logs provide figures on total fuel burned during the period, which is multiplied by average heat content in the fuel to produce total kcal burned. Heat content is obtained through periodic testing, usually once each shift. Total kcal burned is divided by net MWh output.

III.1.19. Hydro unit throughput factor *

\[ \text{Hydro unit throughput factor} = \left( \frac{\text{Actual unit full load capability at available head (MW)}}{\text{Design unit full load capability at same available head (MW)}} \right) \times 100 \]

Defined as the percentage actual MW output to MW design output. When the final design of a hydroelectric generation unit is determined, operating guide curves for MW output at various reservoir levels are established. These curves show the MW amount of output that should be realized at each reservoir level. Design outputs that are not being achieved may indicate that water wheel blades, runner vanes, or control gates are worn through erosion or cavitation. Thus, this indicator should be used as an indicator of hydro unit health and should provide a basis for targeting repair activity.

III.1.20. Full-time equivalent generation operation staff numbers

\[ \text{Net dependable capability (MW)} \]

This indicator measures the operation staffing levels of each plant normalized by MW. If possible the man-years should be accumulated for the following categories: supervisory, skilled operations, skilled maintenance, administrative, fuel handling and unskilled. These should be accumulated annually and compared to MW of net dependable capacity. Thus the manpower levels by position type of various plants can be compared to derive relative efficiencies. Older plants often require more manpower because their design includes more dispersed operating positions. Data on man-hours by category is available from the plant time sheets. The Full-Time Equivalent staff numbers figure is calculated by adding the staff hours of all employed in the category during the period and dividing by the full-time hours of the period. Each staff numbers category is detailed and divided by net dependable plant capability to produce this indicator.

* By unit
** By plant
111.1.21  Routine operations cost

\[ \text{MWh generated} \]

This indicator which measures the operations costs normalized by MWh, should be adjusted for inflation to identify real cost trends over time. All plant operating costs for a period should be added. These costs would exclude fuel, special maintenance and parts, but would include operating labor and expendable operating supplies such as hydrazine and chlorine. This total is divided by the total MWh produced at the plant—providing a plant output basis for comparing operating costs. Newer, larger plants would be expected to have lower operating costs on a per MWh basis. The periodic budget reporting system provides the needed data.

Maintenance Performance Indicators

111.1.22.  Age of major components replaced since the last major overhaul

\[ \text{Expected life of specific components} \]

This indicator measures how well major components have withstood wear. The six-year basis reflects the average elapsed time between major overhauls. Any major components replaced during each cycle should be measured against expected life. If the component exceeded its expected life, appropriate maintenance should be documented; if the component failed too soon, that too should be recorded. This information should be included in the machinery history records for the unit. The data required originates in the plant maintenance work order system.

111.1.23.  Maintenance utilization

\[ \frac{\text{Actual maintenance man-hours}}{\text{Planned maintenance man-hours}} \times 100 \]

This indicator requires a maintenance work order system that estimates time required for jobs as they are received. Actual hours worked are recorded as jobs are completed. Over time, with weekly or monthly reporting, the total estimated maintenance hours can be compared with actual hours spent to yield a utilization percentage. This percentage can be either over or under 100, depending on whether the basis for the estimated hours is liberal or conservative. The maintenance utilization percentage should be used as a tool for measuring overall effectiveness, as an individual performance indicator. The data required originates in the plant maintenance work order system. Actual maintenance hours are divided by total estimated maintenance man-hours for the period.

* By unit
** By plant
111.1.24. Generation maintenance staff numbers

MW installed **

This indicator measures the maintenance staffing years normalized by MW. These staff numbers should be classified using the same categories as operation staffing, which was discussed earlier. These maintenance staff numbers should be the equivalent full-time values and compared with the MW of installed plant capability. Again, older plant and coal-fired plant will require more maintenance. This data is available in the plant maintenance work orders. The total maintenance man-hours worked at the plant is divided by the working hours in the period to convert it to equivalent full time staff numbers and is divided by total MW installed at the plant.

111.1.25. Total maintenance cost

MWh generated **

This indicator, which measures the maintenance costs normalized by MWh, should be adjusted for inflation to identify real cost trends over time. Total annual maintenance costs should be assembled for each plant. These costs include all maintenance labor and maintenance parts used for equipment replacement or repairs, but exclude capital additions. Expendable items such as welding rods should also be included. Any contract maintenance should be added. The annual budget reporting system includes total plant maintenance costs.

* By unit
** By plant
SYSTEM OPERATION PERFORMANCE INDICATORS AND THEIR USE

Objective: Cost-effective use of system capability

Operations Performance Indicators

III.2.1. Dispatch performance

This indicator is a ratio expressing total fuel costs incurred by comparing present dispatching methods with the total fuel cost that could be achieved using the most cost-effective dispatching procedures available. The indicator measures efficiency of the dispatch function. This ratio will obviously be affected by the sophistication of the current dispatch system and the degree to which it can be improved. The potential percent improvement available from enhancement of each type of dispatch procedure, is estimated in the section on system operation. If a system was being dispatched using manual loading tables, the ratio could be 1.3 or higher. If automatic generation control were installed, the ratio could be as low as 1.15. These numbers will vary significantly depending on the sophistication of the utility. The change in the ratio should be tracked as improvements are introduced. Source data are available in system dispatch records.

III.2.2. Interchange purchase cost

\[
\frac{\text{Interchange purchase cost}}{\text{Internal generation cost}}
\]

This indicator shows the cost relationship between interchange purchases and internal generation costs. If possible, the internal generation costs should be those costs which would have been incurred if the load had been met by internal generation and not by purchased power. It measures the benefit received from the utility's energy purchases. Unless the power was purchased for emergency replacement, the interchange purchase cost per MWh should be less than for native generation. The cost of interchange purchases is available from the interchange accounting records maintained by system dispatch. Internal generation costs are available in the budget report data.

III.2.3. Internal generation cost

\[
\frac{\text{Internal generation cost}}{\text{Interchange sales cost}}
\]

This indicator shows the cost relation between different internal generation and interchange sales. If possible, the internal generation costs should be those costs which are incurred to produce the incremental interchange power sales. It measures the relative benefit received from the utility's energy sales. Interchange sales should produce more revenue per megawatt than the internal generation cost. If not, the interchange sales transaction should probably not have been made. The revenue produced by interchange sales is available from interchange accounting records.
111.2.4. **Interchange purchase (MWh) . 100**

This indicator shows the proportion of interchange purchases to total native generation. It measures the degree to which interchange purchases were used. This ratio should be tracked over time to determine whether more economical purchases are being made. The total MWh of interchange purchases and total MWh generated in the native system are available from system dispatch records.

111.2.5. **Interchange sales (MWh) . 100**

This indicator is similar to the preceding one. It measures the degree to which energy sales were made. The total MWh of interchange sales and total MWh generated are available from system dispatch records.
FUEL SUPPLY PERFORMANCE INDICATORS AND THEIR USE 1/

Objective: Provide reliable sources of fuel

Performance Indicators

111.3.1. **System unserved energy (MWh) caused by shortages of fuel supply**. 100 MWh generated for the system

This indicates the overall ability of the fuel supply function to provide a reliable source of fuel for operation. The source for data on system unserved energy is the system dispatch logs which show the MWh of intentionally shed load, as well as the MWh resulting from under frequency operation.

111.3.2. **MWh of restricted plant operations (full and partial) caused by lack of fuel**. 100 8,760. MW capacity of plant

This measure further refines the measurement of overall reliability by identifying restricted plant operations caused by fuel shortages. These restrictions, in all likelihood, create the need to run more expensive units elsewhere. The source of the MWh of restricted plant operations is the station operating logs. One should determine those hours during which a specific unit was not available due to lack of fuel to fire the unit. This figure should be multiplied by the unit capability and the product should be multiplied by the average capacity factor in all other hours. Derations as a result of insufficient fuel situations should also be accounted for.

111.3.3. **Annual short-term fuel quantity**. 100 Quantity of long-term fuel under contract

This indicator provides a measure of fuel supply stability. A utility with exclusively long-term contracts normally has a more stable supply than a utility with short-term contracts. The source for the short-term and long-term fuel under contract is the utility's accounting or fuel procurement records.

111.3.4. **Annual amount of shortfalls and overages**. 100 Total fuel delivered (by vendor) under long-term contracts

This indicator provides a measure of the reliability of the utility's long-term vendors. Unreliable vendors can lead to additional costs if higher-cost fuel must be procured to compensate for shortfalls or if higher carrying costs of inventory are caused by delivery of too much fuel. The source for the amount of shortfalls and overages is the fuel procurement records.

1/ All indicators should be by fuel type and plant, if possible.
Objective: Provide fuel of appropriate quality to meet plant fuel specifications and environmental quality constraints

111.3.5. \( \text{MWh restricted plant operations (full and partial) caused by non-conformance to environmental quality constraints} \times 100 \) \( \frac{\text{capacity of plant}}{8,760} \)

This indicator provides a measure of how well delivered fuel conforms to environmental quality constraints. The source for this information would be system operating logs at the central dispatch office.

111.3.6. \( \text{MWh restricted plant operations (full and partial) caused by non-conformance to plant fuel specifications} \times 100 \) \( \frac{\text{capacity of plant}}{8,760} \)

This indicator provides a measure of the conformance of delivered fuel to plant fuel specifications. The source of this information would be similar to the previous indicator.

111.3.7. \( \text{Amount of fuel not conforming to contractual requirements} \times 100 \) \( \frac{\text{Total fuel delivered}}{\text{Total fuel delivered}} \)

This indicator identifies the amount of fuel not conforming to contractual requirements. This should be derived for all contractual specifications in which quality is considered, such as those dealing with sulfur, ash, etc. Depending on the severity of the non-conformance, use of poor-quality fuel can lead to restricted plant operations. The source for data concerning fuel not conforming to contractual requirements is the fuel sampling results at each plant.

111.3.8. \( \text{Amount of oil required for flame stabilization in solid fuel plants} \times 100 \) \( \frac{\text{MWh generated}}{\text{MWh generated}} \)

Oil is used for flame stabilization in solid fuel units when the quality of the fuel is poor. Thus, this indicator provides a good overall measure of fuel quality. The source for data on oil is the plant fuel logs.

Objective: Provide fuel at cost effective price

Performance Indicators

111.3.9. \( \text{Fuel Transportation costs} \times 100 \) \( \frac{\text{Total delivered fuel cost}}{\text{Total delivered fuel cost}} \)

Transportation costs should be monitored closely to identify potential cost savings. This indicator tracks transportation cost changes. The source for the transportation costs is the vendor's bill; the source data on total delivered fuel cost is account records.
111.3.10. Demurrage cost charges  = 100
Total delivered fuel cost

Demurrage costs are incurred when the fuel cannot be unloaded in accordance with contractual time requirements. This indicator provides a measure of this cost and, therefore, permits evaluation of plant scheduling and unloading practices. The source for the demurrage charges is the transporter's bills.

111.3.11. Total cost of delivered fuel
kWh generated

This is an important indicator because fuel costs often represent more than 50% of total generation costs. Small changes in this indicator can reflect large changes in costs. The source of data for this information is the system operating logs and accounting records. This indicator should be adjusted for inflation to identify real cost trends.

111.3.12. Fuel costs  = 100
Total utility revenues

This indicator provides information similar to the above indicator, but on a ratio—rather than a $/kWh—basis. The source of data is in the system operating logs and accounting records.

111.3.13. Minimum and maximum plant inventory level (by month) during the year converted to days of burn at full output

A utility's carrying costs for fuel can be significant and inventory levels should be monitored. The level of fuel inventory should be based on a cost/benefit analysis of these carrying charges versus the probability and corresponding cost of running out of fuel. This indicator assists in this evaluation. The source for the inventory levels is plant inventory logs. Days of burn at full output would be computed using the plant's historical operating records.

111.3.14. Annual average plant inventory level converted to days of burn at full output

This indicator provides an overall measure of the fuel inventory management function. This figure should be evaluated in the same manner as the materials management function. The source of data for the inventory levels is in the plant inventory logs.

111.3.15. Actual turnover of fuel inventory

\[ \text{Actual turnover of fuel inventory} = \frac{\text{Average quantity fuel in plant stock} \times \text{Fuel unit cost}}{\text{Total fuel cost}} \]

This indicator provides the same information as the above indicator, but is expressed in turnover rather than days burn. The source of data for the inventory levels is in the plant inventory logs.
III.3.16. **Average cost of fuel in inventory** \( \frac{100}{\text{Annual fuel costs}} \)

This indicator provides information on the relative cost of inventory to total fuel costs and will provide similar information as the turnover figures. The source of data for the cost of fuel in inventory is in inventory records.

III.3.17. \( \frac{\text{Price of spot fuel}}{\text{Price of long-term fuel}} \)

A fuel procurement manager works to balance a reliable source of fuel with his minimum cost objective. If spot coal is cheap versus long-term coal, then tradeoffs should be made in evaluating reliability criteria. The source of data for the price of fuel is in accounting records.

III.3.18. \( \frac{\text{Incremental costs of additional fuel procured to meet shortfalls}}{\text{Total fuel costs}} \cdot 100 \)

This indicator provides specific information on the cost to the utility of replacing shortfall long-term contracts with other fuel sources. The source data for the price of fuel is in accounting records. This is a difficult (but very useful) figure to obtain because purchases necessitated by specific shortfalls would have to be tracked.
PERFORMANCE INDICATOR REPORTING DOCUMENT
FOR HEAT RATE OF UNIT C

Date: Month Two, Year One
Department: Generation General Manager

<table>
<thead>
<tr>
<th>Unit C heat rate</th>
<th>Performance indicator #2, #3, etc.</th>
</tr>
</thead>
</table>

I. Current reporting information
- Current operating level 2,597 kcal/kWh
- Current target 2,597 kcal/kWh
- Acceptable deviation 0 kcal/kWh
- Actual deviation 0 kcal/kWh
- Exception report needed No
- Gain (loss) in net benefits for period 0 kcal/kWh

II. Year-end reporting information
- Originally planned target 2,597 kcal/kWh
- Acceptable deviation 0 kcal/kWh
- Revised targets 2,597 kcal/kWh
- Exception report needed No
- Gain (Loss) in net benefits for period 0 kcal/kWh

III. Project management status
- Description of project Installation of cyclonic separator
- Planned completion Month 12, Year One
- Acceptable deviation 15 Days
- Expected completion Month 12, Year One
- Difference 0
- Exception report needed No
ACTION PLAN REPORTING DOCUMENT
FOR HEAT RATE OF UNIT C

<table>
<thead>
<tr>
<th>Date:</th>
<th>Month Two, Year Two</th>
</tr>
</thead>
<tbody>
<tr>
<td>Department:</td>
<td>Generation General Manager</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Action plan #1</th>
<th>Action plan #2</th>
<th>Action plan #3</th>
</tr>
</thead>
</table>

I. Description of action plan
   Improve heat rate with installation of cyclonic separator

II. Initial estimates
   - Targets: 2,559 kcal/kWh
   - Annual net benefits: $110,000

III. Update of current status
   - Target
     --Current planned: 2,559 kcal/kWh
     --Acceptable deviation: 6 kcal/kWh
     --Current actual: 2,572 kcal/kWh
     --Current difference: 13 kcal/kWh
   - Estimated net benefits
     --Current planned: $110,000
     --Current actual: $107,000
     --Current difference: ($3,000)
   - Exception report needed: Yes

IV. Revised long-term estimate
   - Target
     --Long-term originally planned: 2,559 kcal/kWh
     --Long-term now expected and acceptable deviation: 2,559 kcal/kWh
     --Long-term difference: 0
   - Annual net benefits
     --Long-term originally planned: $110,000
     --Long-term now expected: $107,000
     --Long-term difference: ($3,000)
   - Revised action plan necessary: No
   - Exception report needed: No
DISCUSSION OF GENERATION PERFORMANCE INDICATORS

This appendix provides additional information on generation function activities of an electric utility—including generation operation, generation maintenance, system operation, and fuel supply. Related objectives and performance indicators are summarized in Exhibits III-1, III-2, and III-3 (Chapter III).

Generation Operation. The primary function of generation operation is to produce power from the native system generation units when that power is needed to meet system load requirements. Part of this obligation involves supplying adequate power at all times. This is usually accomplished by maintaining spinning reserve at levels sufficient to equal the output of the largest single generation unit. This provides the capability to replace this loss quickly if any unit is tripped out.

Operations is also obligated to produce power at or near the design capability of the generating units' output. Failure at this task can indicate that operators are unwilling or unable to work diligently and continuously for maximum output.

Operations must also avoid mistakes of procedure and judgment that can lead to unit damage or inefficiency. Operators must continuously monitor unit efficiency, indicated by heat-rate data showing the kWh yield relationship to kcal input. The shorter the interval between performance and monitoring data, the earlier the operator can make adjustments that produce more efficient and more cost-effective results.

A final operations performance category is operating costs, the most significant of which is operator labor (fuel costs are evaluated in heat-rate performance). The prime determinant of operator labor costs is the number of operator positions that must be filled during each shift. If an additional operator or supervisory position is required for each shift, five permanent employees must be hired to fill the 21 shifts that the generating unit operates during each week. (Assumes three eight-hour shifts daily and rest days.)

Generation Maintenance. The top priority of generation maintenance is to keep the generation units in condition to produce power when required. This requires regular maintenance—an activity that can be measured with the equivalent forced outage indicators and with the backlog indicator, which can be tracked accurately with a work order system.

Effective maintenance also requires sufficient manpower which is indicated by the average weeks of work remaining, and it requires efficient application of maintenance labor, which is measured by utilization

1/ Experience shows, for example, that steam units tend to operate more efficiently at the 0.9 full-load level and diesels at the 0.8 full-load level.
indicators. Maintenance resources must also be allocated to those repair activities that most urgently require attention. Resource information to accomplish this is gathered by reviewing MWh loss related to specific major components.

Finally, maintenance must be cost effective. Too much maintenance increases maintenance costs without improving component reliability or efficiency. Total maintenance cost/MWh can show if overall levels of maintenance are excessive but pinpointing where maintenance should be reduced requires analysis of machinery history.

Machinery history, including maintenance, should be recorded separately for each generating unit. With these records, maintenance trends and patterns can be established for each component, which in turn provide the basis for determining maintenance requirements. These requirements should specify inspection/repair frequency, such as every year or every other year. Preventive maintenance requirements should also be stated, with notations on frequency of oiling, greasing, and cleaning activity.

System Operation. System operation is designed to dispatch the available native generation units efficiently, so that load requirements can be handled reliably. System operation must therefore be effective in:

* committing units,
* loading units,
* scheduling maintenance, and
* transacting interchange sales and purchases.

The dispatch performance ratio indicator measures the effectiveness of these activities. This indicator compares fuel costs under current dispatching operations with fuel costs under the estimated most cost-effective dispatching operation. The procedure for doing this is described in the case study in this chapter.

Native system generation can be supplemented by interchange purchases. Conversely, native generation might be required to support interchange sales. Either way, interchanges must be carefully monitored to ascertain that they are in the best economic interest of the utility.

Fuel Supply. The fuel supply function is critical because fuel costs often represent more than 50% of a utility's total costs. The primary objective in fuel supply is providing a reliable source of fuel. Aggregate measures of success in meeting this objective are the system energy unserved indicator and the indicator showing number of MWh of restricted plant operations caused by lack of fuel. Fuel supply stability can be measured by
comparing purchases of short-term fuel and purchases of long-term fuel. More long-term fuel indicates a more stable supply of fuel. Vendor performance can be evaluated by tracking the amount of shortfall and/or overage by vendor.

Fuel supply is also responsible for appropriate quality fuel, which can be monitored in the number of MWh of restricted plant operation caused by failure to conform with environmental and/or plant fuel specifications. Another measure is the amount of fuel not conforming to contractual requirements. Coal quality is indicated by the amount of oil needed for flame stabilization.

Another major area of concern for the fuel supply function is providing fuel at cost-effective prices. Information on the specific and relative cost of fuel is available by examining the sub-components of the fuel cost (transportation and demurrage), the total cost of fuel delivered, and fuel costs as a percentage of revenues. The cost of fuel is affected by inventory, which entails carrying charges. Several measures of inventory are useful, including minimum and maximum inventory levels related to periods of burn, number of days burn in average inventory, inventory turnover, and the cost of fuel inventory as a percentage of the utility's total annual fuel costs. Other indicators useful for evaluating the cost effectiveness of the fuel supply function are spot fuel prices compared to long-term fuel prices and the incremental costs of additional fuel procured to meet shortfall.
USE OF OTHER CRITICAL GENERATION PERFORMANCE INDICATORS TO IDENTIFY POTENTIAL COST-EFFECTIVE IMPROVEMENTS USING THE PI/MRS PROCESS

This appendix discusses performance indicators that are not discussed in case studies.

**Equivalent Availability Factor.** Utilities worldwide have difficulty keeping the equivalent availability factor at acceptably high levels. Generation capability losses, whether a result of scheduled or forced outage, entails equipment that is not available to meet system load requirements. This can significantly increase utility costs.

Monitoring availability—particularly for the most efficient and cost effective units—is an important activity. The higher the equivalent availability for these units, the more they can operate. If the most cost-effective units run more, the average cost of power declines.

For the hypothetical electric system, an availability increase for units A, B, and C (see Appendix III-C) would lead to the greatest cost reduction. If the equivalent availability of only one of these three machines were increased by 5%, the annual fuel savings would total about $1.5 million.

**Forced Outage Rate.** The most effective way to raise a unit's availability is to lower its forced outage rate. If unit B's forced outage rate were lowered by 5%, availability would increase by 5%. This would allow the output factor to rise by about 4%, saving fuel by displacing power from less fuel-efficient units.

Forced outage should contribute less to unavailability than planned outage. If unit A had an equivalent availability of 75%, then the 25% total unavailability should be composed of about 15% scheduled outage and 10% forced outage. Scheduled outages are preferable because they can be planned for low power cost periods and appropriate supplies and mechanical repair craftsmen can be available.

**Output Factor.** Output factor for thermal generation units is important because it clearly demonstrates the value of each unit to the utility system. The higher the output factor, the more the unit was used during the time it was available. Thus, units with high output factors are prime targets for maintenance attention, so that availability can be increased and these valuable units can contribute even more heavily to generation.

This is not the objective, however, with energy-limited generation sources such as hydroelectric units. Hydro units are usually the most valuable in the system, because of their low energy cost and ability to provide spinning reserves. Hydro units often have low output factors of necessity, due to restrictions in pond storage, evaluation fluctuation, and seasonal inflow. Annual output factors for thermal generation units seldom exceed 80%—a higher figure would indicate that the unit was running near maximum capacity whenever it was in service. A common high output factor is
60 to 80%, depending on the period of time considered and the utility load fluctuations.

**Percentage Reserve.** While percentage reserve targets are primarily planning objectives, they can be applied to operations. This is particularly true for spinning reserves, which provide quick load pick up following loss of either native generation units or tie lines carrying interchange purchases. Thus, the spinning reserves should be at least equal to the largest unit or tie-line inflow.

If on-line units are not capable of responding adequately to avoid frequency drop, then additional units should be kept partially unloaded for spinning reserve support. Hydro units are particularly valuable for their capability of providing extremely fast response.

**System Percentage Difference Between Design Net Dependable Capability and Actual Net Dependable Capability.** All utilities must make the fullest possible use of their investments in generating capacity. New units are planned to operate at the design level for net dependable capability. The design output level, priced on a kW basis, is also a criterion for deciding which new units should be acquired. With new plant capacity costing $800 to $2,000/kW, reaching design levels is particularly important.

When actual net dependable capability does not reach the design level, the utility is not receiving full value for its capital outlay. Design shortcomings can be the reason for the shortcoming, in which case the equipment manufacturer should be urged to make corrections. Operation and maintenance obstacles can also cause design level shortfalls, in which case the causes should be addressed and alternative actions identified and considered.

**Fuel Costs Per kWh Generated.** When segregated by the size and type of unit, this measure can indicate important trends in the critical area of fuel costs. An increase in this indicator signals that a closer investigation of the utility's operations is warranted.

**Total Cost of Energy Delivered Per kWh Sold for the System.** This indicator is important because it provides the bottom-line cost measure for the utility. A gradual rise in this figure may be caused by increasing price levels, but a rapid increase indicates the need for a detailed investigation to determine the cause.

**Total Full-Time Equivalent Generation Employees Per System MW.** Generation labor required to produce power is an important contributor to generation costs. In general, hydro generation requires the fewest employees per megawatt of capacity, followed by diesel, gas, oil, and coal in ascending order.

Utilities that employ predominantly hydro or gas generation typically have 0.1 to 0.2 employees per MW, while utilities that are predominantly oil- and gas-fired, show ratios of 0.3 to 0.5. Only utilities
with similar fuel mixes should be compared. Comparisons should also be made separately for operating and maintenance employees.

Comparisons should also consider varying overtime policies. A company that traditionally permits 20% overtime to be worked and manages overtime effectively, will require fewer employees than a company that permits only 10% overtime. For valid comparisons, data should incorporate contract maintenance employees (or their equivalent).

Aggregate Indicators. In general, aggregate indicators--such as total staffing years per customer and overall O&M cost per kWh--are not useful for identifying cost effective improvements in a utility. They can be useful, however, for identifying areas that warrant further investigation--much as aggregate statistics analysis is used for the same purpose (see Chapter II). Such indicators should be compared with year-earlier measurements. The cause of any year-to-year changes, if it can be determined, should be carefully documented for future reference.

Major Changes in Indicators. If major changes in generation indicators are recorded, areas that need further attention can be identified easily. Such changes should be noted on reporting documents.
Recall that the three steps of this PI/MRS element are:

- Identifying desired performance levels and comparing them with the utility's actual performance level to identify potential cost-economy and efficiency-improvement opportunities.
- Determining feasibility and cost benefits of achieving the desired performance level.
- Developing an action plan,

Each of these steps will be discussed in the case studies of system heat rate and dispatch performance and value of interchange.

SYSTEM HEAT RATE CASE STUDY

Background. Average system heat rate can be defined as the number of kilocalories necessary to produce one kWh. \(^1\) System heat rate in effect measures unit efficiency. This case study addresses improvements in the heat rates of individual units and not in the overall system heat rate. This is because overall system heat rate can be affected by other variables--such as changes in availability--which are not addressed in this case study.

For the hypothetical utility, unit sizes, fuel types, and heat rates are assumed to be as follows:

---

\(^1\) Heat rate changes between minimum and maximum output for each unit--a relationship that can be plotted as a heat rate curve. This case study, however, will only address average heat rate.
<table>
<thead>
<tr>
<th>Unit</th>
<th>Size</th>
<th>Description</th>
<th>Actual heat rate kcal/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>200 MW</td>
<td>Coal fired (20 years old)</td>
<td>2,622</td>
</tr>
<tr>
<td>B</td>
<td>250 MW</td>
<td>Coal fired (10 years old)</td>
<td>2,572</td>
</tr>
<tr>
<td>C</td>
<td>250 MW</td>
<td>Coal fired (9 years old)</td>
<td>2,597</td>
</tr>
<tr>
<td>D</td>
<td>100 MW</td>
<td>#6 Oil fired (15 years old)</td>
<td>2,723</td>
</tr>
<tr>
<td>E</td>
<td>150 MW</td>
<td>#6 Oil fired (12 years old)</td>
<td>2,673</td>
</tr>
<tr>
<td>F</td>
<td>150 MW</td>
<td>#6 Oil fired (10 years old)</td>
<td>2,648</td>
</tr>
<tr>
<td>G</td>
<td>200 MW</td>
<td>Gas fired (8 years old)</td>
<td>2,622</td>
</tr>
<tr>
<td>H</td>
<td>15 MW</td>
<td>Diesels (30 years old)</td>
<td>4,413 1/</td>
</tr>
<tr>
<td>I</td>
<td>20 MW</td>
<td>Diesels (26 years old)</td>
<td>4,539</td>
</tr>
<tr>
<td>J</td>
<td>20 MW</td>
<td>Diesels (24 years old)</td>
<td>4,488</td>
</tr>
<tr>
<td>K</td>
<td>20 MW</td>
<td>Diesels (22 years old)</td>
<td>4,337</td>
</tr>
<tr>
<td>L</td>
<td>25 MW</td>
<td>Diesels (23 years old)</td>
<td>4,388</td>
</tr>
<tr>
<td>M</td>
<td>30 MW</td>
<td>Oil combustion turbines (13 years old)</td>
<td>4,917</td>
</tr>
<tr>
<td>N</td>
<td>30 MW</td>
<td>Oil combustion turbines (11 years old)</td>
<td>4,539</td>
</tr>
<tr>
<td>O</td>
<td>40 MW</td>
<td>Oil combustion turbines (9 years old)</td>
<td>4,615</td>
</tr>
<tr>
<td></td>
<td>1,500 MW</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1/ In addition to the 1,500 MW listed above, the hypothetical utility also has 500 MW of hydro (2-25 MW, 5-40 MW, 5-50 MW).

2/ Diesel heat rates are unusually high (compared to steam), reflecting low plant factors and inefficient operation.

Various plant managers are assumed to be responsible for the heat rates of individual units. The annual savings that can result from a plant's heat rate improvements are significant. Assuming, for example, that a plant can improve its heat rate by 3% annually, a 300 MW coal unit that consumes approximately $20,000,000 of fuel annually can provide annual fuel savings of $600,000. One utility's actual management review identified a potential 3% improvement for a 525 MW unit—offering annual net savings (benefits minus costs) of $800,000. Other management reviews have identified similar savings. Because unit age and use cause a gradually decreasing heat rate, this area is especially productive in offering potential cost savings.
Identifying Desired Performance Levels and Comparing to Utility's Actual Performance Level, to Identify Potential Cost-Effective Improvement Opportunities. Using the analysis techniques described in Chapter II, the following quantitative information is available. 1/

- **Intracompany Work Units**—Because the age and size of units vary widely, general comparisons of the heat rate of units within the system are not particularly useful. The technique is useful, however, for comparing units that are very similar (same size, installed at about the same time, major components supplied by the same manufacturer, and overhauled approximately at the same time). For the hypothetical utility, the units assumed to be comparable (using these criteria) are units B and C and units E and F.

- **Intracompany Management and Efficiency Studies**—The most effective management and efficiency standard for heat rate is the manufacturer's design heat rate.

- **Intracompany Performance Indicator Analysis Over Time**—This is measured by considering the unit's heat rate change since its most recent overhaul. For this type of comparison it is useful to show the heat rate graphically for the last several years. This provides the manager with information that is easy to review. Table IIIC-1 depicts the heat rate for Unit C over the past six years. The graph shows that the heat rate before the last overhaul was 2,633 and the heat rate immediately after the overhaul was 2,522. This graph shows the gradual increase in the heat rate (or decrease in efficiency) of Unit C.

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1/ For both case studies, specific numbers will be assumed to provide the information necessary for understanding the PI/MRS process. In using the PI/MRS process, however, a utility would determine this type information.
TABLE III-C-1

GRAPHICAL PRESENTATION OF UNIT C'S
CHANGE IN HEAT RATE OVER LAST SIX YEARS

<table>
<thead>
<tr>
<th>Year One</th>
<th>Year Two</th>
<th>Year Three</th>
<th>Year Four</th>
<th>Year Five</th>
<th>Year Six</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Rate (kcal/kWh)</td>
<td>2,700</td>
<td>2,633 kcal/kWh</td>
<td>2,600</td>
<td>2,597 kcal/kWh</td>
<td>2,522 kcal/kWh</td>
</tr>
</tbody>
</table>

Time

(last overhaul)
### TABLE III-C-2

**STATISTICAL INFORMATION AND DESIRED PERFORMANCE LEVELS FOR UNIT HEAT RATES**

<table>
<thead>
<tr>
<th>Unit</th>
<th>Current heat rate (kcal/ kWh)</th>
<th>Annual output heat rate (%)</th>
<th>Design heat rate (kcal/ kWh)</th>
<th>Years since/after major overhaul</th>
<th>Heat rate after last overhaul (kcal/ kWh)</th>
<th>Desired heat rate to desired performance level (kcal/ kWh)</th>
<th>Difference from actual heat rate after last overhaul (%)</th>
<th>Difference from heat rate after last overhaul (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>2,622</td>
<td>63</td>
<td>2,522</td>
<td>4/2</td>
<td>2,559</td>
<td>2,547</td>
<td>3.0</td>
<td>0.5</td>
</tr>
<tr>
<td>B</td>
<td>2,572</td>
<td>65</td>
<td>2,471</td>
<td>4/2</td>
<td>2,496</td>
<td>2,496</td>
<td>2.9</td>
<td>0</td>
</tr>
<tr>
<td>C</td>
<td>2,597</td>
<td>64</td>
<td>2,471</td>
<td>3/3</td>
<td>2,522</td>
<td>2,496</td>
<td>4.0</td>
<td>1.0</td>
</tr>
<tr>
<td>D</td>
<td>2,723</td>
<td>40</td>
<td>2,547</td>
<td>5/1</td>
<td>2,673</td>
<td>2,622</td>
<td>3.8</td>
<td>1.9</td>
</tr>
<tr>
<td>E</td>
<td>2,673</td>
<td>42</td>
<td>2,572</td>
<td>2/4</td>
<td>2,673</td>
<td>2,648</td>
<td>3.0</td>
<td>1.0</td>
</tr>
<tr>
<td>F</td>
<td>2,648</td>
<td>43</td>
<td>2,572</td>
<td>1/5</td>
<td>2,635</td>
<td>2,622</td>
<td>1.0</td>
<td>0.5</td>
</tr>
<tr>
<td>G</td>
<td>2,622</td>
<td>54</td>
<td>2,597</td>
<td>1/5</td>
<td>2,597</td>
<td>2,597</td>
<td>1.0</td>
<td>0</td>
</tr>
<tr>
<td>H</td>
<td>4,413</td>
<td>8</td>
<td>3,909</td>
<td>3/3</td>
<td>4,287</td>
<td>4,236</td>
<td>4.2</td>
<td>1.2</td>
</tr>
<tr>
<td>I</td>
<td>4,539</td>
<td>6</td>
<td>4,035</td>
<td>3/3</td>
<td>4,438</td>
<td>4,438</td>
<td>2.3</td>
<td>0</td>
</tr>
<tr>
<td>J</td>
<td>4,488</td>
<td>9</td>
<td>4,035</td>
<td>4/2</td>
<td>4,362</td>
<td>4,337</td>
<td>3.5</td>
<td>0.6</td>
</tr>
<tr>
<td>K</td>
<td>4,337</td>
<td>11</td>
<td>4,035</td>
<td>1/5</td>
<td>4,287</td>
<td>4,287</td>
<td>1.2</td>
<td>0</td>
</tr>
<tr>
<td>L</td>
<td>4,388</td>
<td>10</td>
<td>4,035</td>
<td>2/4</td>
<td>4,337</td>
<td>4,337</td>
<td>1.2</td>
<td>0</td>
</tr>
<tr>
<td>M</td>
<td>4,917</td>
<td>5</td>
<td>4,539</td>
<td>5/1</td>
<td>4,791</td>
<td>4,690</td>
<td>4.8</td>
<td>2.2</td>
</tr>
<tr>
<td>N</td>
<td>4,539</td>
<td>7</td>
<td>4,413</td>
<td>3/3</td>
<td>4,488</td>
<td>4,488</td>
<td>1.1</td>
<td>0</td>
</tr>
<tr>
<td>O</td>
<td>4,615</td>
<td>6</td>
<td>4,413</td>
<td>4/2</td>
<td>4,564</td>
<td>4,539</td>
<td>1.7</td>
<td>0.6</td>
</tr>
</tbody>
</table>

Comparable Performance Indicator Analysis Over Time—This comparison is useful if the size, age, manufacturer by major component, and the last overhaul of units of various utilities are known. The survey of comparable utilities does not provide this kind of detail; thus, this data base is not directly useful. The survey can be used, however, to establish ranges of average heat rates for units of comparable size and age. Such ranges can compensate for the fact that specific overhaul and manufacturer information is not available.

This information can be used to identify desired performance levels and potential improvement opportunities by devising a table that examines the
range of comparable heat rates from the comparable utility survey data, the unit's design heat rate, output factor, the unit's actual heat rate, and the heat rate after the last overhaul. Based on the age and other operating characteristics of the unit, a desired performance level can be established. 

Table III-C-2 presents this information for the various units (see Appendix III-D for the comparable survey data), as well as the percentage deviations from the desired performance level of the actual heat rate and the heat rate after the last overhaul.

The desired performance level heat rate is the level considered most cost effective for the unit. A comparable figure is the heat rate immediately after the most recent overhaul. The heat rate after the last overhaul may be equal to the desired performance level (indicating that the overhaul practices are probably adequate), or higher (indicating that changes in overhaul practices could be beneficial). The change from the desired performance level to the current heat rate identifies the potential for cost-effective improvements. Not all improvement opportunities entail major overhauls, so the desired performance level should serve only as a benchmark for potential opportunities. For example, it may be more cost effective to make small improvements rather than to perform a major overhaul, even though the major overhaul will produce the desired performance level.

This case study will examine only one unit in detail to identify specific improvement opportunities. In actual practice, a utility would select the top three to five candidates for a more detailed analysis and would likely initiate several concurrent improvement programs if warranted by the cost benefit analysis and available resources.

Identifying the unit with the most improvement potential, not only requires looking at the unit showing the greatest gap between desired performance level heat rate and actual heat rate, but also factoring in the change in the heat rate since the last overhaul and when the next major overhaul is planned. Our hypothetical utility is assumed to have all units on a six-year overhaul schedule. Thus, a unit that has not been overhauled for five years may not be the best candidate for improvement, because the unit will be overhauled in the following year. The unit with the greatest total improvement potential is often a unit with less of a performance gap but more years to the next overhaul.

Unit C is selected as the unit with the greatest potential for improvement because it appears to have the highest potential payback by achieving the desired heat rate performance level. This unit, which was

1/ As noted in Chapter II, desired performance levels are largely based on management judgment and should be used as benchmarks in the PI/MRS process. The utility may well find that it is not cost beneficial to try to attain this level. A detailed investigation may also indicate that a level even better than the original target can be attained.
overhauled three years ago, has a design heat rate of 2,471. After its last
overhaul, the unit had a heat rate of 2,522. The desired performance level
(after overhaul) is estimated to be 2,496. This represents a difference of 1%
between the heat rate after the last overhaul and the desired performance
level. The unit's current heat rate of 2,597 represents a 5.1% degradation
from the design heat rate and a 4.0% degradation from the desired performance
level. Based on a detailed cost-benefit analysis (not shown in the manual),
these characteristics are judged to indicate that Unit C has the highest
potential payback.

Determining Feasibility and Cost Benefits of Achieving the Desired
Performance Level and Estimated Cost Effective Improvements. If the 101 kcal/
kJWh heat rate improvement from the current heat rate (2,597) to the desired
performance level (2,496) can be realized, then, if one assumes a MWh value of
$5.46, 1/ the improvements will yield annual savings of more than $300,000. 2/

The approach used to determine if some or all of these savings can
be achieved--outlined in Chapter II--is to identify specific steps (in prelim-
inary action plans) that can be taken to move toward the desired performance
level and then to determine if those steps are cost effective. Improvement
opportunities applicable to all units in the system, may be uncovered in the
analysis of Unit C. If these improvements are cost effective they should be
implemented immediately.

One of the first steps in ascertaining which improvements could
produce lowered heat rates is pinpointing where unit efficiency is being
lost. Two data sources are valuable for making this determination.

   The first source is plant operating records that show which major
   components have caused reduced plant output. These plant output restrictions
   can be related to heat rate by determining the impact of the failed component
   on plant efficiency.

   Most plants develop rather specific and predictable operating
   problems. During its nine years of operation, Unit C has been plagued with
   chronic electrostatic precipitator clogging. This clogging results from
   excessive fly ash in the hot gas path (more ash than the precipitator can

1/ The $5.46 per MWh is representative of the incremental value of an
additional MWh of output, based on an efficiency utility's generation
costs. This value is used throughout this report, but it should be
adjusted by an individual utility to reflect its replacement power costs.

2/ To calculate the estimated benefits, multiply the percentage improvement
(4%) by the unit capability (250 MW), then multiply this product by hours
in a year (8,760) times the assumed capacity factor of 65% to yield MWh
improvement, then multiply the MWh by the $5.46, yielding $310,000
savings (4% x 250 MW x 8,760 x 0.65 x $5.46 = $310,000).
collect unless all of its cells are operating). The precipitator was designed to collect 99.5% of all fly ash from the exit gases of the unit while operating at its 250-MW full load. This performance level was to have been achieved with only 12 of the total 16 cells in service. The excess fly ash is also blocking some of the air preheater baskets, so that the primary air entering the furnace is not sufficiently prewarmed. The primary air must instead be heated by burning pulverized coal, which further reduces unit efficiency. The temperature increase inside the air preheater is designed to be 121°C, but in fact is averaging only 79°C.

The second data source is maintenance records showing the major components that require the most attention. Unit C's air preheater has required frequent washing to remove accumulated fly ash, requiring the unit be off line. Maintenance records also show a higher than normal failure rate for the negative grids and positive electrodes within the precipitator cells. The cells must be isolated to replace failed parts, causing reduced collecting efficiency and increased heat rate. Such conclusions can be drawn only if both operating and maintenance records are organized and accessible. Otherwise, information is available only from what employees are able to remember.

With the problems causing lost efficiencies identified, the next step is to assess which remedies might be cost effective. Given the set of problems with Unit C, the following three general approaches should be considered:

- Capital improvements.
- Operating procedure modifications.
- Increased maintenance.

(1) Capital Improvements. A cyclonic separator can be placed in the gas path to capture some (about 10%) of the fly ash before it reaches the precipitator. The separator, including ash disposal lines, would cost about $75,000 to fabricate and install. Following fabrication, the separator could be installed during a planned two-week annual boiler inspection/repair. Fabricating and installing the cyclonic separator would require one year.

The addition of more precipitator cells, each costing about $50,000, is another capital alternative. Because at least four additional cells would be needed, the minimum cost would be $200,000. Labor required to install each cell would cost some $10,000. Additionally, a four-week outage would be required, adding two weeks to the scheduled boiler outage. The one-time outage is assumed to cost $84,000 in replacement energy.

An engineering analysis shows that 38 kcal/kWh can be regained through each of these capital improvements—a total annual value of more than $110,000.
(2) Operating Procedure Modifications. If the unit's normal operating capacity were reduced by 10% to 225 MW, the present precipitator configuration should operate satisfactorily. This 25 MW reduction would have to be replaced with higher cost generation (entailing additional costs of about $200,000 per year). This assumes a $1 per MWh cost differential between the operating cost of Unit C and its replacements.

Another operating option would be closer surveillance of the precipitator by the auxiliary operator. When ash buildup is detected, the generation unit loading could be reduced so that the mechanical rappers could clear the accumulated fly ash. This option would not require a continuous deration, so its costs would be less than the $200,000 associated with a permanent deration. Total annual costs would likely be approximately $110,000--$100,000 for deration and $10,000 for additional operating labor.

For each of these options, it is assumed that about 38 kcal/kWh can be regained, for annual savings of $110,000.

(3) Increased Maintenance. The entire unit could be taken out of service over a weekend (or similar period when the system load is down) to clear the precipitator, wash the air heater, and repair any faulty precipitator grids or electrodes. The cost of this option would vary with the number of required outages, but a single weekend outage would cost about $12,000 in energy cost differential plus about $2,000 in labor and materials. If an outage were required each month (a quite conservative estimate), the annual cost would be $168,000. This option also assumes that 38 kcal/kWh could be regained, for annual savings of $110,000.

Other power plant problems are often dealt with more effectively through maintenance than through capital modifications. As an example, Unit C should be considered for major overhaul more frequently than every six years. Seldom is it appropriate for every unit to conform to the same overhaul frequency, because units have differing economic values and maintenance needs. Thus, it is important to determine the appropriate cycle based on economic considerations and not merely based on adherence to a convenient timetable.

In considering the range of options, priority should be given to achieving immediate cost-effective improvements, with subsequent attention to identifying opportunities for long-range cost savings by using more advanced technology at additional cost. Once the range of options for increasing the unit's efficiency has been identified, a matrix should be developed that shows
all costs and benefits of the approaches. Table III-C-3 shows such a matrix and indicates that only two of the alternatives are cost beneficial. 1/

Utilities will have different priorities and available resources for making cost-beneficial changes.

Developing an Action Plan. An action plan is intended to formalize the specific steps (with targets and intermediate progress goals) that will achieve the cost savings. A formal process establishes a plan that can be used as a guide for implementing the improvement action and monitoring its progress. Sub-action plans, based on this action plan, should be developed for use below the manager level to ensure that subordinates are fully aware of steps required to implement the overall action plan.

This action plan includes the following phases:

* Re-evaluating the initial cost-benefit analysis.
* Developing specific recommendations and implementation for unit with highest priority.
* Developing recommendations applicable to the overall system.
* Evaluating other units for improvement and selecting the next unit to be improved.

The first two phases of this action plan are described in detail below. 2/

---

1/ The cost-benefit analysis has been kept fairly simple. In practice, however, such an analysis can be complicated by many factors--such as the phasing in and out of benefits and costs, transportation costs, import taxes, capital budgeting considerations, net present value, and more detailed analysis techniques. Although this manual does not discuss these techniques, utility analysts should be fully knowledgeable of the intricacies of conducting cost/benefit analyses.

2/ Phases III and IV should start up as a utility gains experience with the in-depth unit analysis in Phase II, to develop a system-wide program for improvement.
<table>
<thead>
<tr>
<th></th>
<th>Initial cost</th>
<th>Annual operating cost</th>
<th>Benefits</th>
<th>Cost/benefit analysis</th>
<th>Net present value for 5-year period b/</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Equipment cost</td>
<td>Labor cost</td>
<td>Replace a/</td>
<td>Capital</td>
<td>Labor</td>
</tr>
<tr>
<td><strong>A. Capital improvements</strong></td>
<td></td>
<td></td>
<td>energy cost</td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Add cyclonic separator</td>
<td>62</td>
<td>13</td>
<td>0</td>
<td>75</td>
<td>-</td>
</tr>
<tr>
<td>* Add precipitator cells</td>
<td>200</td>
<td>40</td>
<td>84</td>
<td>324</td>
<td>-</td>
</tr>
<tr>
<td><strong>B. Operating procedure modifications</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Reduce load</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td>* Provide continuous surveillance</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
<tr>
<td><strong>C. Increased maintenance</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>* Wkd. outage to clear precipitator and wash the air heater</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>0</td>
<td>-</td>
</tr>
</tbody>
</table>

a/ This is a one-time energy cost incurred during equipment installation.

b/ This figure shows the total present worth of net benefits for a five-year period computed at 15% discount rate.
Phase I: Review initial feasibility and cost-benefit analysis indicating that Unit C is highest priority unit.

(1) Time Frame. Three months.

(2) Target/Milestones. A final action plan with proposed costs and benefits to be formulated by end of the three months.

(3) Costs. $15,000 (three man-months of engineering analysis time). 1/

(4) Benefits. Confirmation of the priority listing indicating which generation plants and units can realize greatest average heat rate performance improvements and where remedial action is most beneficial.

Phase II: Step 1--Identify and set priorities for specific remedial recommendations to increase average unit heat rate of Unit C. Each candidate improvement should be related to a specific heat rate target improvement.

(1) Time Frame. Six months.

(2) Target/Milestones. A hierarchical listing of unit modifications and resulting heat rate improvements, with elapsed time considered.

(3) Costs. $10,000 (two months of engineering analysis time) plus $10,000 (two man-months of assistance by plant experienced generation engineering personnel).

(4) Benefits. A list of actions--showing costs and benefits--that will significantly improve average heat rates for Unit C.

Phase II: Step 2--Develop and carry out an implementation strategy that concentrates first on completing the simplest projects offering the greatest cost-benefit returns. The first project would therefore be installation of the cyclonic separator.

(1) Time Frame. Installation should be completed in one year.

(2) Target/Milestones. Cost savings should be realized in the first year following installation.

(3) Costs. $75,000 for initial installation.

(4) Benefits. Annual benefits of $110,000 beginning in year two.

1/ Engineering analyst time is assumed to cost $5,000 a month. Note these and all other costs are based on fully loaded (wages plus benefits) compensation of typical U.S. utilities employers.
A Summary Action Plan is presented in Table III-C-4, which can be used for upper management review and overall monitoring.

**TABLE III-C-4**

**SUMMARY OF HEAT RATE ACTION PLAN**

**Overview of Action Plan**

This action plan is designed to identify specific opportunities for improving the heat rate of the system's units and act on these opportunities.

**Implement Steps**

- **Phase I**—Review initial feasibility and cost-benefit analysis and any additional issues, revising approach as necessary.
- **Phase II**—Develop specific remedial recommendations to increase average unit heat rate for highest priority unit. For Unit C, the first action should be cyclonic separator installation.
- **Phase III**—Develop recommendations applicable to the entire system.
- **Phase IV**—Evaluate potential improvements in other units and select next candidate.

**Costs of Action Plans**

- **Phase I** — $35,000 (engineering analysis time).
- **Phase II** — $75,000 for cyclonic separator installation. There would be no operational costs.
- **Phase III** — Still undetermined.
- **Phase IV** — Still undetermined.

**Net Benefits of Action Plan**

Implementing the cyclonic separator plan yields a net present value of $234,000 over five years, using a 15% discount factor.
DISPATCH PERFORMANCE AND VALUE OF INTERCHANGE CASE STUDY

Background. This case study addresses the important objective of achieving cost-effective operations by efficiently using the utility's generation resources. It addresses the dispatch operations function and focuses on short-term decisions that must be made by the dispatcher. The value of interchange has been made part of the case study because it represents one of the decisions made regularly by the dispatcher.

This case study discusses ways of evaluating dispatch performance and achieving improved operating results. The ultimate target is to improve dispatch economics and move toward a desired performance level. The desired level is, the dispatch level that is most cost effective.

The dispatching area is seldom targeted as an important area for cost savings. This is because dispatching improvements are difficult to quantify and because management generally lack understanding of the potential for system operations improvements. Experience has shown, however, that significant improvements can be made in the dispatching area. For example, an actual management review identified dispatching-operations improvements offering potential in net savings of several million dollars annually. Other management reviews have similarly shown that the dispatching area offers high potential for cost-effective improvements.

Identifying Desired Performance Levels and Comparing them to the Utility's Actual Performance Level, to Identify Potential Cost-Effective, Improvement Opportunities. The major analysis technique used in this area is a management and efficiency study that attempts to determine the most efficient way to dispatch the utility's units.

The first step in this process is evaluating the following four basic areas to determine if the utility is dispatching at the most efficient level:

- Generation unit commitment procedures.
- Generation control procedures.
- Interchange. 1/

These four areas most often offer the following types of opportunities for dispatch performance improvement:

1/ Most countries do not currently have extensive interchange power capabilities or transactions. Interchange is included in this area, however, because it represents a significant cost-effective improvement potential.
Maintenance Scheduling—By scheduling the most valuable units to be out of service for maintenance during periods when load is down and cost of power is lowest, the average cost of power can be reduced.

Generation Unit Commitment—Typical opportunities involve improving the utility's procedures for committing and loading its native generating equipment. As utility loads change on a seasonal, weekly, or daily cycle, the utility must start (commit) or stop (decommit) generation units. Achieving an optimum commit-schedule, usually for one week at a time, minimizes extra costs caused by not having the appropriate units on line.

Generation Control Procedures—Efficient unit loading is achieved by using units that are already on line to achieve the most economical output that meets system demand. Where the system size justifies the investment in control equipment, efficient loading can be achieved through an automated closed-loop control system, which sends signals to each controlled unit every few seconds. These signals initiate an increase or decrease of unit load so that system demand can be met economically. There are other (less effective) systems, however, that also serve this purpose.

Interchange—Sales to other utilities at a price higher than the cost to generate the power provides additional revenue. This revenue can then be used to reduce the cost of delivered power. Purchases from other utilities or from industrial cogenerators within the native system can also serve to reduce the delivered cost per kWh. Purchases made at less than incremental cost of producing native generation provide a net savings.

The estimated potential improvement opportunities in these four basic areas should be quantified by using present operating conditions as a base. The cost of system operation for any given period—such as an hour, week, month, or year—can be approximated by calculating the actual generation unit loading and associated fuel consumption. Fuel consumption can be derived from the average heat rate. Summing each individual unit's fuel costs yields total system costs.

For each potential improvement, such as an improved unit commitment, the cost of current procedures can be compared with costs of the improved procedures. This quantifies the value of undertaking each improvement. For example, each unit loading during each hour of the week examined, should be multiplied by that unit's heat rate and fuel cost. This exercise should be performed for existing conditions and potential improved conditions, so that relative fuel costs can be determined and a cost-benefit value of this action can be determined.
The purpose of the exercise is to look for improvements continually that will yield a more cost-effective, dispatching operation. This calculation can be completed manually, or by using computer models—which simplify the process and permit consideration of specific constraints and their effects. These models can be run on many microcomputers.

Whichever calculation procedure is adopted, it is vital to quantify system operating costs for current operations and for alternative improvements. The computer model permits easier projection of the cost-effective dispatching level (desired performance level), because these models devise optimum system operation within dictated constraints. Manual calculation usually requires permutations of possible alternatives so that a feasible desired performance level can be identified.

By comparing the utility's current dispatching operations to the most cost-effective dispatching level (desired performance level), a dispatch performance percentage can be established and the utility will have identified cost-effective actions that help it move toward the desired performance level. Capital requirements and other constraints, however, may prohibit achieving the desired performance level immediately. Further, additional experience with this approach may show that the desired performance level should be adjusted.

The key in this step is to arrive at a preliminary estimate of the most cost-effective dispatch performance level to determine whether potential improvement possibilities exist. For the next element, a more detailed analysis should be performed. Experience has shown that dispatching operations offers several opportunities for immediate improvement.

For the hypothetical utility, the preliminary analysis identified an assumed dispatch performance ratio of 1.2. That is, current dispatching operations incur fuel costs that are 20% higher than those projected by the estimate of the most cost-effective dispatching operations. This points to significant opportunities for improvement.

Determining Feasibility and Cost Benefits of Achieving the Desired Performance Level and Estimated Cost-Effective Improvements. The following paragraphs describe certain specific methods that permit more detailed analyses to identify specific improvement opportunities for the hypothetical utility. For purposes of this discussion, the utility is assumed to have a 60% annual output (load) factor, a 1,500 MW peak demand, and an average fuel cost per kWh of $0.546. Annual fuel costs therefore total $43 million. Given the 1.2 dispatch performance ratio, the utility can potentially realize annual savings of $7.2 million, or 16% of fuel costs.

- Maintenance Scheduling—The effectiveness of current maintenance scheduling procedures should be established first, to determine the benefit potential. The initial step is to calculate a value for each unit in each month of the year. Monthly data is preferred because seasonal load changes will be
considered. The value for each unit is established in the simulation by first dispatching the system with the unit and then without. The difference between these two yields the value for that unit.

This dispatching method should be the one usually used to match load and generation—whether a loading table based on fuel costs or an automated control system. With either, results should be consistent.

Next, the succeeding year's maintenance schedule as planned should be superimposed, with calculations showing both unit values and average cost of energy delivered. The most efficient and valuable units should have overhauls scheduled when energy costs are lowest. During the next cheapest periods, the next most efficient units should be scheduled.

If overhauls have not been scheduled as efficiently as possible, this analysis will show that lowest power cost periods are not being effectively exploited. With the utility's 60% output factor a significant opportunity to adjust the scheduled maintenance appropriately is quite likely to be indicated. Depending on unit sizes and heat rate differences, the maintenance schedule savings can easily reach 1% of annual energy costs, or $430,000.

Generation Unit Commitment Procedures—Many utilities continue to use a fixed loading table, which lists the commitment order for all units. This tends to ignore important variables, such as load levels to be met, changes in load over time, minimum generation unit up and down times, unit response rates, start-up costs, and cycling capability. These variables often change the commitment order, so that no fixed-unit approach is always best.

The value of an optimal unit commitment program—which produces the best unit commitment for up to 168 hours—is in the range of 2% to 4% of total generation costs or, for the hypothetical utility, $860,000 to $1,720,000 annually. The 2% to 4% figure is based on experience with utilities that have installed automated energy control systems. For other utilities, this figure could be 6% to 10%.

The best approach to unit commitment is an automated one that initiates a new commitment run at least once daily and more often if loads or other conditions change unexpectedly. Such programs are available for $50,000 to $100,000 and run on many microcomputers.
The commitment of hydroelectric units presents some unique considerations that should be addressed before the commitment of fossil-fueled generating units is completed. Because the incremental cost of generation at existing hydro stations is relatively low, these stations should be used to offset (displace) the highest-cost generation that would otherwise run. 1/ In the hypothetical utility system, these highest-cost units are the diesel and combustion turbine units.

Before generation units are committed, a target amount of hydro generation should be established. If the hydro facility includes no reservoir storage capability, then the hydro energy must be taken evenly throughout the 168 hours of the week. The most efficient use of hydro energy, however, is for peak shaving. To the extent possible, all hydro generation should be applied first during peak hours.

The result of allocating hydro in specific hours will be to reduce total fuel costs to the maximum extent possible. Agricultural or recreational objectives that require water discharge must, of course, be met. Also seasonal flood and spill conditions must be considered.

- **Generation Control Procedures**—If automated closed-loop generation control capability is not in place for all major generation units, then the utility might wish to determine the costs and benefits of providing such control. Automatic generation control systems provide a raise or lower signal to each controlled generator every few seconds. This yields most efficient use of on-line generation.

Automatic generation control systems for a utility the size of the hypothetical utility cost $1.5 million to $2.5 million when all communications, computer, and remote terminal equipment is included. Such systems, however, offer fuel savings of up to 5% annually ($2.1 million) versus manual loading techniques.

- **Interchange Power**—Both the current level of interchange sales and purchases and the potential for sales and purchases should be examined. If a spread of 10 mills (¢1) per kWh can be achieved between interchange purchase cost and the cost to generate internally a 100 MW purchase for one week, a savings of $168,000 can be achieved.

A 10-mill difference between purchase cost and generation cost is not extraordinary—it can often be much greater. This is

1/ Subject to the efficient use of the available water.
particularly true if combustion turbine energy is being displaced or hydro energy is being purchased. The same economics work for sales to other utilities. If the utility can achieve revenues in excess of generation cost, savings can be realized.

Interchange transactions require available transmission capacity to link the buying and selling companies. Transmission that is constructed to ensure reliability can often be used for interchange. If the interchange is financially advantageous, additional transmission can be constructed solely on the basis of interchange savings.

To evaluate the various cost-saving options adequately, a cost-benefit analysis matrix similar to the one discussed for the heat rates is useful.

**Developing an Action Plan.** Action plans presented in this case study address only the generic elements for identified areas of improvement. More specific action plans based on these generic elements should be developed. Before any of these generic action plans is initiated, however, an initial feasibility study should be conducted, focusing on estimating the dispatch performance percentage and estimated potential cost savings. The study would be cursory (one man-month, costing $2,500), designed to identify potential cost savings and substantiate the need for more detailed (and more costly) studies in the four generic areas.

* Maintenance Scheduling

**Step 1:** Perform initial feasibility and cost-benefit analysis to confirm initial estimates.

1. **Time Frame.** Three months.

2. **Target/Milestones.** A final action plan with proposed maintenance schedule changes that shows the value of each generation unit and value of energy for each time frame.

3. **Costs.** Six man-months of engineering analyst time—approximately $30,000. 1/

4. **Benefits.** Quantified unit values that can be used to improve maintenance scheduling and to serve as a guide to appropriate allocation of maintenance resources.

---

1/ Engineering analyst time is assumed to cost $5,000 monthly.
Step 2: Develop and implement specific maintenance scheduling strategies that will result in lower energy costs.

(1) Time Frame. Maintenance is usually scheduled annually; so, the new scheduling methodology should be in place before the next maintenance scheduling cycle.

(2) Target/Milestones. Implementing the new scheduling methodology based on the unit valuation technique.

(3) Costs. The calculation and implementation should not take over one man-month of engineering analyst time—approximately $5,000.

(4) Benefits. Will depend on whether any previous attempt was made to optimize maintenance scheduling. Conservative estimate projects annual savings of 1/2 of 1% of the total energy cost, or $215,000.

* Unit Commitment Procedures

Step 1: Perform initial feasibility and cost-benefit analysis.

(1) Time Frame. One month. Examining present unit commitment procedures and determining if an automated approach would be superior is a straightforward process.

(2) Target/Milestones. The first target is to document current unit commitment procedures. The next target is to determine improvements that an automated approach can provide when considering multiple variables for each hour of the study. Also, a review should be made to determine the availability, cost, and computer requirements for unit commitment programs.

(3) Costs. Not more than two man-months of engineering analyst time—approximately $10,000.

(4) Benefits. Documenting current procedures and determining likely benefits.

Step 2: Select and implement an improved unit commitment methodology.

(1) Time Frame. Selection should take about six months and complete implementation another six months.
(2) Target/Milestones. The selection of the unit commitment package is the first milestone. The second milestone is implementation. Care must be exercised to adopt an approach that is not too arduous for employees who will be using the package to make hour-by-hour unit commitment decisions. These people are likely to be dispatch or operations support personnel who are not particularly comfortable with data entry and program execution. The support of these employees is essential for the program to achieve projected benefits.

(3) Costs. Software should cost between $50,000 and $100,000; hardware (micro-computer systems) should cost no more than $10,000.

(4) Benefits. A unit commitment program, which is run once each day (more often if conditions change), can yield savings of between 2% and 4% of the total cost of generation or, for the hypothetical utility, $860,000 to $1,720,000 annually. Also, the availability of a unit commitment tool that accurately simulates system dispatch can be readily used to produce generation unit values required by the improved maintenance scheduling routine.

* Generation Control Procedures

Step 1: Perform initial feasibility and cost-benefit analysis.

(1) Time Frame. The documentation of current generation control procedures should be completed in two months. The specification of what additional control capability is worthwhile should take another four months.

(2) Target/Milestones. The first milestone is documenting present procedures. The second milestone is specifying and evaluating improved generation control procedures. The third milestone is recommending an improved generation control capability that focuses on total project costs and benefits.

(3) Costs. The specification and feasibility study would likely involve both utility personnel and an outside control-system consultant. This study should be completed in less than 20 man-months of engineering analyst time, or $100,000.
(4) Benefits. Quantified generation control approaches and their prospective values when applied to the utility's operating environment.

**Step 2:** Select and implement an improved generation unit control procedure.

(1) Time Frame. Selection should take about six months, but implementation of even a basic "off-the-shelf" system will require at least another year and a half.

(2) Target/Milestones. The first milestone is selecting an approach. The second is selecting a vendor to supply the system, and providing a specific statement of work for the vendor. The process is completed with system implementation and field testing.

(3) Costs. An automatic generation control system for a utility the size of the hypothetical utility costs between $1.5 to $2.5 million when all communications, computer, and remote terminal equipment is included.

(4) Benefits. Benefits from automatic generation control can range from a 1% to 5% savings (of total fuel cost). A 5% saving would yield a benefit of more than $2 million annually. Automated systems would have additional value to electric operations after they have been justified by generation control savings. These basic applications areas include load monitoring, switch control, and feeder loading and flow indications.

*Interchange Power*

**Step 1:** Perform initial feasibility and cost-benefit analysis.

(1) Time Frame. Two months.

(2) Target/Milestones. An action plan that identifies any existing interchange power activities and determines the capability of existing tie-lines to transfer power. The capability analysis must consider electric system reliability and operating contingencies, as well as the basic economics that can support interchange transactions. If the economic analysis precludes large year-round exchanges, then smaller, seasonal load valley-fill and peak-shaving opportunities should be explored. Load-flow studies should be run for verification.
(3) Costs. Approximately two months of an engineering analyst's time and two months of an electrical engineer's time, or approximately $20,000 plus computer time for load-flow analysis.

(4) Benefits. Identification of interchange power capability and opportunities.

Step 2: Develop specific interchange power recommendations to either purchase power to offset higher native generation costs or to sell power to produce additional revenue.

(1) Time Frame. To examine existing tie-lines and neighboring utilities to determine interchange possibilities will require about three months. To identify and study the need for new transmission facilities to support future interchange will require about six months.

(2) Target/Milestones. A listing of current interchange opportunities, with corresponding constraints and projected economic benefits. A second listing should be made of those interchange activities that could be completed if additional transmission were constructed. Each item on the second list should show proposed transmission construction costs and associated potential benefits.

(3) Costs. Costs to initiate an interchange power contract should be less than 10 man-months of engineering analyst time, or $50,000. Multiple contracts with different utilities would possibly double this cost. New transmission construction could cost anywhere from $100,000 to several million dollars, depending upon scale.

The Summary Action Plan is presented in Table III-C-5.
TABLE III-C-5

SUMMARY OF ACTION PLAN FOR DISPATCH PERFORMANCE
AND VALUE OF INTERCHANGE

Overview of Action Plan

This action plan identifies opportunities for more cost-effective dispatching of generating plant.

Implementation Steps

The first step in implementing the plan would be to conduct a short study (1/2 man-month, or $2,500) to determine the dispatch performance percentage and identify the potential cost savings from improvements. If savings are cost beneficial, then each of the four basic improvement areas (maintenance scheduling, unit commitment procedures, generation control procedures, and interchange), would be investigated by doing the following:

- Performing initial feasibility and cost-benefit analysis.
- Developing and implementing specific strategies that will result in lower energy costs.

Cost and Benefits of Action Plan

The cost of the action plan will vary depending on which options the utility pursues. For the hypothetical utility, the benefits of the action plan could possibly yield savings of $7.3 million annually (16% of fuel costs) if the utility is able to move toward the most cost-effective dispatch level.
SURVEY RESULTS COMPILING COMPARATIVE GENERATION PERFORMANCE
INDICATORS FROM SELECTED UTILITIES AROUND THE WORLD 1/

Definitions of Graphs/Tables

To ensure proper interpretation of these values, they are defined as follows:

* **Minimum Value** - The lowest data point on the frequency distribution.

* **Maximum Value** - The highest data point on the frequency distribution.

* **Mean Value** (\( \bar{x} \)) - The average—computed as the summation of data observations divided by the total number of observations.

* **Standard Deviation** (\( S_d \)) - A measure of the data variation around the mean value computed as:

\[
S_d = \sqrt{\text{Var } x}
\]

\[
\text{Var } x = \frac{\sum (x_i - \bar{x})^2}{n}
\]

1. **Average Annual Unit Heat Rate**

Heat Rate = A measure of generating unit thermal efficiency, generally expressed as kcal per kWh. It is computed by dividing the total kcal content of the fuel burned (or of heat released from a nuclear reactor) by the resulting kWh net generation (i.e. gross kWh minus station service).

2. **Equivalent Availability Factor and Availability Factor by Unit**

A. **Availability Factor** = \( \frac{\text{Available hours}}{\text{Period hours}} \) \times 100 (%)

Available Hours = Hours that a piece of equipment was available for service (service hours + reserve shutdown)

Period hours = Hours in period (e.g. 8,760 in one year)

1/ See Chapter II for a discussion of survey methodology.
B. Equivalent Availability Factor =

\[
\text{Equivalent Forced and Scheduled Partial Outage Hours} = \left( \text{Avail. - Equivalent forced and scheduled partial outage hours} \right) \cdot \frac{100}{\text{Period hours}}
\]

Equivalent Forced and Scheduled Partial Outage Hours - The sum of hours during partial load reduction adjusted to reflect equivalent hours of maximum load outage hours.

\[
\text{(Derated capacity in MW in terms of forced or scheduled capacity)} \cdot \text{(hours derating applies)} \cdot \frac{100}{\text{Full site rating in MW's}}
\]

3. Forced Outage Rate by Unit - The forced outage rate categorizes and summarizes equipment failures and their corresponding outage periods. It characterizes the inability of a unit to operate when required for service. Scheduled outages are excluded when computing this index. It is equal to:

\[
\frac{\text{Forced outage hours}}{\text{Service hours} + \text{Forced outage hours}} \cdot 100\%\]

NOTE: Although equivalent forced outage rate is more useful, it is not a commonly used indicator.

4. Output Factor by Unit - The output factor represents the average operating load of a unit while actually synchronized to the system during a specified period. Operating losses due to load following, economic dispatch, deratings, and start-up/shutdowns and ramping requirements affect the factor. It is equal to:

\[
\frac{\text{Total gross generation (MWh)}}{\text{Service hours} \cdot \text{Maximum dependable capacity (MW)}} \cdot 100\%
\]

Maximum Dependable Capacity - The long-term rating of the unit based on normal operating conditions, sometimes taking account of the effects of ambient temperature and altitude.

---

1/ Ramping is defined as the process of acceptable and progressive machine load acceptance without risk of excessive mechanical deformation and stress.
5. **Percentage Reserve (Spinning and Cold Reserve)** - Reserves are measured as a percentage of peak load. There are various classifications for operating reserves, defined below.

   A. **Spinning Reserve** - Unused capability of units that are synchronized with the system, which can be used to respond quickly to load increases.

   B. **Fast-Start Reserves** - Unused capability that, while not synchronized with the system, can be synchronized within 5 to 10 minutes if needed (usually combustion turbines and diesels).

   C. **Hot-Start Reserves** (Hot Standby) - Thermal capability that is not synchronized with the system but that is at or near operating temperature (dry-steam conditions exist within the boiler).

   D. **Cold Reserves** (Cold Standby) - Thermal capability in an ambient temperature state that is available for start-up (i.e. not on maintenance or cold storage) and can be synchronized within normal cold-start time required.

6. **Generation Employees/MW Installed Plant by Plant Type**

   A. **Generation** - Includes operations and maintenance staffing at the power station. Total generation employees is the summation of:

      - **Management**: Salaried employees in a supervisory/management function at power station.

      - **Skilled**: Degreed engineers, degreed non-engineers, non-degreed hourly employees performing jobs at the power station requiring skilled training.

      - **Support**: Secretarial and other support staff at power station.

      - **Unskilled**: Hourly employees at power station performing jobs requiring no skilled training.
The following figures are attached:

* Figure III-D-1: U.S. Operating Performance Indicators (Annual Heat Rate)
* Figure III-D-2: U.S. Operating Performance Indicators (Availability Factor [%])
* Figure III-D-3: U.S. Operating Performance Indicators (Equivalent Availability Factor [%])
* Figure III-D-4: U.S. Operating Performance Indicators (Forced Outage Rate [%])
* Figure III-D-5: U.S. Operating Performance Indicators (Output Factor [%])
* Figure III-D-6: U.S. Generic Performance Indicator (Generation Employees per MW of System Capacity)
* Figure III-D-7: U.S. Generic Performance Indicator (Percentage Reserve)
* Figure III-D-8: International Operating Performance Indicators (Annual Heat Rate)
* Figure III-D-9: International Operating Performance Indicators (Availability Factor)
* Figure III-D-10: International Operating Performance Indicators (Equivalent Availability Factor)
* Figure III-D-11: International Operating Performance Indicators (Forced Outage Rate)
* Figure III-D-12: International Operating Performance Indicators (Output Rate)
* Figure III-D-13: International Generic Performance Indicator (Generation Employees per MW of System Capacity)
* Figure III-D-14: International Generic Performance Indicator (Percentage Reserve).
### U.S. Operating Performance Indicators

**INDICATOR:** Annual Heat Rate (kcal/kWh)

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<th>Fuel</th>
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<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
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<td>752</td>
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<tr>
<td>Nuclear</td>
<td></td>
<td>2,562</td>
<td>2,959</td>
<td>2,758</td>
<td>139</td>
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</tbody>
</table>
# 6 OIL UNITS
51 - 100 MW
ANNUAL HEAT RATE

# 6 OIL UNITS
101 - 200 MW
ANNUAL HEAT RATE

# 6 OIL UNITS
51 - 100 MW
DATA DISTRIBUTION

# 6 OIL UNITS
101 - 200 MW
DATA DISTRIBUTION

# 2 OIL UNITS
ANNUAL HEAT RATE

# 2 OIL UNITS
ANNUAL HEAT RATE
DATA DISTRIBUTION
U.S. Operating Performance Indicators

**INDICATOR:** Availability Factor (%)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1 - 100</td>
<td>77</td>
<td>99</td>
<td>89</td>
<td>5</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>20</td>
<td>100</td>
<td>83</td>
<td>13</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>36</td>
<td>100</td>
<td>77</td>
<td>15</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 50</td>
<td>53</td>
<td>100</td>
<td>86</td>
<td>15</td>
</tr>
<tr>
<td></td>
<td>51 - 100</td>
<td>57</td>
<td>100</td>
<td>91</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>57</td>
<td>99</td>
<td>80</td>
<td>13</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>53</td>
<td>100</td>
<td>86</td>
<td>10</td>
</tr>
<tr>
<td>#2 Oil</td>
<td>1 - 100</td>
<td>89</td>
<td>100</td>
<td>94</td>
<td>4</td>
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<tr>
<td>Hydro</td>
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<td>86</td>
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<td>96</td>
<td>4</td>
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<tr>
<td>Gas</td>
<td>1 - 100</td>
<td>33</td>
<td>100</td>
<td>90</td>
<td>13</td>
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<tr>
<td></td>
<td>101 - 200</td>
<td>52</td>
<td>96</td>
<td>87</td>
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<td></td>
<td>201+</td>
<td>55</td>
<td>95</td>
<td>83</td>
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</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td>15</td>
<td>100</td>
<td>69</td>
<td>20</td>
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</tbody>
</table>
FIGURE IIIID-2 Cont.

COAL UNITS
1 - 100 MW
AVAILABILITY FACTOR
DATA DISTRIBUTION

COAL UNITS
101 - 200 MW
AVAILABILITY FACTOR
DATA DISTRIBUTION

COAL UNITS
201+ MW
AVAILABILITY FACTOR
DATA DISTRIBUTION

# 6 OIL UNITS
1 - 50 MW
AVAILABILITY FACTOR
DATA DISTRIBUTION
FIGURE IIID-3

U.S. Operating Performance Indicators

INDICATOR: Equivalent Availability Factor (%)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
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<td>72</td>
<td>98</td>
<td>87</td>
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<tr>
<td></td>
<td>201+</td>
<td>24</td>
<td>96</td>
<td>64</td>
<td>16</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 50</td>
<td>52</td>
<td>100</td>
<td>84</td>
<td>17</td>
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<tr>
<td></td>
<td>51 - 100</td>
<td>57</td>
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<td>90</td>
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<td>101 - 200</td>
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</tr>
<tr>
<td></td>
<td>201+</td>
<td>48</td>
<td>98</td>
<td>76</td>
<td>11</td>
</tr>
<tr>
<td>#2 Oil</td>
<td></td>
<td>89</td>
<td>100</td>
<td>95</td>
<td>4</td>
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<tr>
<td>Hydro</td>
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<td>65</td>
<td>100</td>
<td>95</td>
<td>6</td>
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<td>100</td>
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</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>40</td>
<td>96</td>
<td>82</td>
<td>17</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>49</td>
<td>92</td>
<td>77</td>
<td>14</td>
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<tr>
<td>Nuclear</td>
<td></td>
<td>43</td>
<td>85</td>
<td>62</td>
<td>13</td>
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</tbody>
</table>
Cont.

# 6 OIL UNITS
51 - 100 MW
EQUIVALENT AVAILABILITY FACTOR

# 6 OIL UNITS
101 - 200 MW
EQUIVALENT AVAILABILITY FACTOR

# 6 OIL UNITS
51 - 100 MW
DATA DISTRIBUTION

# 6 OIL UNITS
101 - 200 MW
DATA DISTRIBUTION

# 6 OIL UNITS
201+ MW
EQUIVALENT AVAILABILITY FACTOR

# 2 OIL UNITS
EQUIVALENT AVAILABILITY FACTOR

# 6 OIL UNITS
201+ MW
DATA DISTRIBUTION

# 2 OIL UNITS
DATA DISTRIBUTION
HYDRO UNITS NATURAL GAS UNITS
EQUIVALENT AVAILABILITY 1-100 MW EQUIVALENT AVAILABILITY FACTOR

DATA DISTRIBUTION DATA DISTRIBUTION

NATURAL GAS UNITS 101-200 MW EQUIVALENT AVAILABILITY FACTOR

DATA DISTRIBUTION DATA DISTRIBUTION
NUCLEAR UNITS
EQUIVALENT AVAILABILITY

DATA DISTRIBUTION

MEAN = 62
## U.S. Operating Performance Indicators

**Indicator:** Forced Outage Rate

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1 - 100</td>
<td>0</td>
<td>9</td>
<td>3</td>
<td>2</td>
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<tr>
<td></td>
<td>101 - 200</td>
<td>0</td>
<td>51</td>
<td>9</td>
<td>10</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>1</td>
<td>50</td>
<td>13</td>
<td>10</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 50</td>
<td>0</td>
<td>25</td>
<td>4</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>51 - 100</td>
<td>0</td>
<td>25</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>0</td>
<td>43</td>
<td>13</td>
<td>13</td>
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<tr>
<td></td>
<td>201+</td>
<td>0</td>
<td>22</td>
<td>8</td>
<td>6</td>
</tr>
<tr>
<td>#2 Oil</td>
<td></td>
<td>0</td>
<td>60</td>
<td>19</td>
<td>21</td>
</tr>
<tr>
<td>Hydro</td>
<td></td>
<td>0</td>
<td>24</td>
<td>2</td>
<td>4</td>
</tr>
<tr>
<td>Gas</td>
<td>1 - 100</td>
<td>0</td>
<td>78</td>
<td>13</td>
<td>22</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>0</td>
<td>31</td>
<td>4</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>1</td>
<td>12</td>
<td>6</td>
<td>4</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td>1</td>
<td>31</td>
<td>11</td>
<td>8</td>
</tr>
</tbody>
</table>
COAL UNITS
1 - 100 MW
FORCED OUTAGE RATE

0-8 8-15 15-25 25-35 35-45 45-55 55-65 65+

COAL UNITS
101 - 200 MW
FORCED OUTAGE RATE

0-7 7-15 15-25 25-35 35-45 45-55 55-65 65+

COAL UNITS
1 - 100 MW
DATA DISTRIBUTION

COAL UNITS
101 - 200 MW
DATA DISTRIBUTION

COAL UNITS
201+ MW
FORCED OUTAGE RATE

0-3 3-6 6-9 9-12 12-15 15-18 18-21 21+

# 6 OIL UNITS
1 - 50 MW
FORCED OUTAGE RATE

0-2 2-3 3-4 4-5 5-6 6-7 7-8 8-9 9-10 10-15 16+

COAL UNITS
201+ MW
DATA DISTRIBUTION

# 6 OIL UNITS
1 - 50 MW
DATA DISTRIBUTION
FIGURE III-4 Cont.

NATURAL GAS UNITS
1 - 100 MW
FORCED OUTAGE RATE

101 - 200 MW
FORCED OUTAGE RATE

DATA DISTRIBUTION

NATURAL GAS UNITS
1-100 MW
FORCED OUTAGE RATE
DATA DISTRIBUTION

101 - 200 MW
FORCED OUTAGE RATE
DATA DISTRIBUTION

NATURAL GAS UNITS
201+ MW
FORCED OUTAGE RATE

NUCLEAR UNITS
FORCED OUTAGE RATE

DATA DISTRIBUTION

NATURAL GAS UNITS
201+ MW
FORCED OUTAGE RATE
DATA DISTRIBUTION

NUCLEAR UNITS
FORCED OUTAGE RATE
DATA DISTRIBUTION
FIGURE IIID-5

U.S. Operating Performance Indicators

INDICATORS: *Output Factor (%)*

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>1 - 100</td>
<td>17</td>
<td>91</td>
<td>69</td>
<td>17</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>38</td>
<td>100</td>
<td>73</td>
<td>13</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>43</td>
<td>95</td>
<td>73</td>
<td>13</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 50</td>
<td>37</td>
<td>76</td>
<td>59</td>
<td>11</td>
</tr>
<tr>
<td></td>
<td>51 - 100</td>
<td>0</td>
<td>81</td>
<td>58</td>
<td>19</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>49</td>
<td>80</td>
<td>65</td>
<td>7</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>32</td>
<td>85</td>
<td>53</td>
<td>15</td>
</tr>
<tr>
<td>#2 Oil</td>
<td>1 - 100</td>
<td>6</td>
<td>73</td>
<td>58</td>
<td>16</td>
</tr>
<tr>
<td>Hydro</td>
<td></td>
<td>6</td>
<td>75</td>
<td>34</td>
<td>20</td>
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<tr>
<td>Gas</td>
<td>1 - 100</td>
<td>0</td>
<td>94</td>
<td>33</td>
<td>28</td>
</tr>
<tr>
<td></td>
<td>101 - 200</td>
<td>30</td>
<td>78</td>
<td>54</td>
<td>12</td>
</tr>
<tr>
<td></td>
<td>201+</td>
<td>42</td>
<td>79</td>
<td>58</td>
<td>10</td>
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<tr>
<td>Nuclear</td>
<td>40</td>
<td>98</td>
<td>85</td>
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<td></td>
</tr>
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</table>
FIGURE IID-5 Cont.

HYDRO UNITS
OUTPUT FACTOR

NATURAL GAS UNITS
1 - 100 MW
OUTPUT FACTOR

NATURAL GAS UNITS
101 - 200 MW
OUTPUT FACTOR

NATURAL GAS UNITS
201+ MW
OUTPUT FACTOR

DATA DISTRIBUTION

DATA DISTRIBUTION
FIGURE IIID-6

U. S. Generic Performance Indicator

INDICATOR: Generation Employees per MW of System Capacity

<table>
<thead>
<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>.11</td>
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<td>.26</td>
<td>.11</td>
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</tbody>
</table>

GEN EMPLOYEES

DATA DISTRIBUTION
**FIGURE IIID-7**

**U. S. Generic Performance Indicator**

**INDICATOR:** Percentage Reserve

<table>
<thead>
<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.00%</td>
<td>15.00%</td>
<td>9.00%</td>
<td>4.25%</td>
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</tbody>
</table>

**PERCENT RESERVE**

**DATA DISTRIBUTION**
### International Operating Performance Indicators

**INDICATOR:** Annual Heat Rate (kcal/kWh)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
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<tr>
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<td>3,219</td>
<td>3,811</td>
<td>3,400</td>
<td>230</td>
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<td>1 - 200</td>
<td>2,445</td>
<td>2,648</td>
<td>2,553</td>
<td>91</td>
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<tr>
<td>Gas</td>
<td>1 - 300</td>
<td>2,269</td>
<td>5,746</td>
<td>3,495</td>
<td>1,267</td>
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<tr>
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<td>2,721</td>
<td>2,764</td>
<td>2,748</td>
<td>17</td>
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</table>
FIGURE IID-8 Cont.

- # 6 OIL UNITS
  - ANNUAL HEAT RATE
  - DATA DISTRIBUTION

- # 2 OIL UNITS
  - ANNUAL HEAT RATE
  - DATA DISTRIBUTION

- NUCLEAR UNITS
  - ANNUAL HEAT RATE
  - DATA DISTRIBUTION

- NATURAL GAS UNITS
  - ANNUAL HEAT RATE
  - DATA DISTRIBUTION
**FIGURE IIID-9**

**International Operating Performance Indicators**

**INDICATOR:** Availability Factor (%)  

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>#2 Oil</td>
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<td>86.60</td>
<td>97.40</td>
<td>94.27</td>
<td>3.68</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 200</td>
<td>44.70</td>
<td>100.00</td>
<td>80.28</td>
<td>12.44</td>
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<tr>
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<td>1 - 300</td>
<td>65.00</td>
<td>100.00</td>
<td>90.11</td>
<td>10.15</td>
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<td>Nuclear</td>
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<td>85.50</td>
<td>90.00</td>
<td>87.50</td>
<td>1.85</td>
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</table>
International Operating Performance Indicators

**INDICATOR:** Equivalent Availability Factor

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<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
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<tr>
<td>#2 Oil</td>
<td>86.60</td>
<td>94.40</td>
<td>90.50</td>
<td>3.90</td>
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</tr>
<tr>
<td>#6 Oil</td>
<td>45.00</td>
<td>100.00</td>
<td>81.54</td>
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<tr>
<td>Gas</td>
<td>45.00</td>
<td>100.00</td>
<td>86.27</td>
<td>12.75</td>
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</tr>
<tr>
<td>Nuclear</td>
<td>86.50</td>
<td>90.50</td>
<td>88.20</td>
<td>1.73</td>
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</tr>
</tbody>
</table>
## International Operating Performance Indicators

**INDICATOR:** Forced Outage Rate

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>#2 Oil</td>
<td></td>
<td>1.50</td>
<td>16.60</td>
<td>7.90</td>
<td>5.60</td>
</tr>
<tr>
<td>#6 Oil</td>
<td>1 - 200</td>
<td>0.00</td>
<td>93.10</td>
<td>30.94</td>
<td>33.57</td>
</tr>
<tr>
<td>Gas</td>
<td>1 - 300</td>
<td>0.35</td>
<td>80.00</td>
<td>16.93</td>
<td>21.63</td>
</tr>
<tr>
<td>Nuclear</td>
<td></td>
<td>0.10</td>
<td>3.40</td>
<td>1.00</td>
<td>1.39</td>
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</tbody>
</table>
FIGURE III-D-11 Cont.

- # 6 OIL UNITS
  - FORCED OUTAGE RATE
  - DATA DISTRIBUTION

- # 2 OIL UNITS
  - FORCED OUTAGE RATE
  - DATA DISTRIBUTION

- NATURAL GAS UNITS
  - FORCED OUTAGE RATE

- NUCLEAR UNITS
  - FORCED OUTAGE RATE

- NATURAL GAS UNITS
  - DATA DISTRIBUTION

- NUCLEAR UNITS
  - DATA DISTRIBUTION
### International Operating Performance Indicators

**INDICATOR:** Output Rate (%)

<table>
<thead>
<tr>
<th>Fuel</th>
<th>MW Category</th>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>#2 Oil</td>
<td>56.70</td>
<td>88.00</td>
<td>69.32</td>
<td>11.47</td>
<td></td>
</tr>
<tr>
<td>#6 Oil</td>
<td>60.00</td>
<td>100.00</td>
<td>70.00</td>
<td>16.04</td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>3.64</td>
<td>65.00</td>
<td>37.30</td>
<td>19.15</td>
<td></td>
</tr>
<tr>
<td>Nuclear</td>
<td>97.00</td>
<td>100.00</td>
<td>98.70</td>
<td>1.03</td>
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</tbody>
</table>
FIGURE IIIID-13

International
Generic Performance Indicator

INDICATOR: Generation Employees per MW of System Capacity

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<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>.13</td>
<td>.93</td>
<td>.41</td>
<td>.26</td>
</tr>
</tbody>
</table>

**GEN EMPLOYEES**

**GEN EMPLOYEES DATA DISTRIBUTION**

![Data Distribution Chart]

**GEN EMPLOYEES DATA DISTRIBUTION**

**GEN EMPLOYEES**

**GEN EMPLOYEES DATA DISTRIBUTION**

![Data Distribution Chart]
FIGURE IIIID-14

International Generic Performance Indicator

INDICATOR: Percentage Reserve

<table>
<thead>
<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.00%</td>
<td>22.00%</td>
<td>9.73%</td>
<td>5.28%</td>
</tr>
</tbody>
</table>

PERCENT RESERVE

DATA DISTRIBUTION

MEAN = 9.73%
CHAPTER IV
APPLICATION TO TRANSMISSION AND DISTRIBUTION ACTIVITIES
OF THE PI/MRS PROCESS

INTRODUCTION

This chapter discusses how the PI/MRS process is applied to the
transmission and distribution (T&D) activities of an electric utility
and provides examples—using a hypothetical utility—to illustrate this
application. 1/

This manual defines a utility's T&D activities as those activities
involving daily operations and maintenance (O&M) of the total T&D system—which includes lines, switching stations, transformation stations, 2/ and
associated equipment emanating from the output (high) side of generator step-up transformers. 3/ This manual considers only major T&D equipment; that is, lines, transformers, circuit breakers, capacitors, and inductors. If desired, a utility can develop indicators for minor equipment items for use by personnel below the manager level. As noted in Chapter II, planning activities are
not discussed in this manual.

Transmission is defined as those circuits that deliver (transmit) power and energy from the generating stations to distribution transformation stations through a network of lines, switching stations, and substations. Distribution is defined as those circuits that deliver (distribute) power and energy from the substations to the customer through a radial feeder configuration. 4/ Typical transmission voltage levels include 115 kV, 138 kV, 230 kV, and 345 kV and greater. 5/ In this manual, subtransmission systems configured as networks (typically, 34.5 kV and 69 kV) and direct current (DC) transmission integrated into the alternating current (AC) transmission system

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1/ Although this chapter can stand alone, T&D personnel may want to read the
other two application chapters (III and V) of this manual to understand better the PI/MRS process is applied to the other major functions of a utility.

2/ Switching stations and transformation stations will be referred to jointly as substations.

3/ Generator step-up transformers are typically included as part of the
generation plant for O&M purposes.

4/ Although there are exceptions to the clear division of configurations into network and radial, they are relatively few and transitional in nature.

5/ Unless otherwise noted, voltage levels refer to alternating current (AC) electrical systems.
are also considered part of transmission. Typical distribution voltage levels include 4 kV, 8 kV, 12.5 kV and 25 kV.

Substations can be classified under either transmission or distribution, depending on the operating voltage levels. This manual treats both classes of substations collectively, except when distinctions are necessary.

It is assumed that each functional area of transmission, distribution, and substations is headed by a manager in the hypothetical utility and that these managers report to the T&D general manager. The T&D general manager reports to the chief executive, who is the utility's chief executive officer.

This chapter is particularly important because T&D operations have a direct effect on the reliability and adequacy of power supply provided to every customer. T&D operation and maintenance costs often account for 15% to 20% of the utility's non-fuel budget, or 7.5% to 10.0% of the utility's overall operating budget. 1/ Excessive T&D losses may also greatly reduce utility revenues and represent unproductive use of installed plant and equipment.

The primary objective of T&D operations is to provide reliable, safe, and efficient power delivery from generating plants to customers, with reasonable service quality (i.e., minimal voltage and frequency fluctuations). This chapter identifies T&D performance indicators that will help accomplish this objective by measuring the extent to which the objective is attained. On an operating level, the following objectives must be attained by managers of the three T&D functions (transmission, distribution and substation).

- Provide reliable service.
- Maximize efficiency.

The remainder of this chapter is divided into six sections that correspond to the six elements of the PI/MRS process described in Chapter II:

- Identifying useful staffing and operational performance indicators.
- Developing the performance indicator data base and reporting requirements.
- Identifying possible cost effective improvement areas and developing action plans to achieve them.
- Developing reporting documents to (1) monitor the cost-effective, improvement plans and (2) provide management with information essential for managing the utility's operations.

1/ Table II-1 on page 14 illustrates these figures.
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* Integrating the PI/MRS process with planning and budgeting cycles to provide incentive for full achievement of cost economies and efficiency improvements.

* Integrating the PI/MRS process into the human resource aspects of the utility.

IDENTIFICATION OF USEFUL STAFFING AND OPERATIONAL PERFORMANCE INDICATORS FOR THE T&D ACTIVITIES OF A UTILITY

Manager Level Performance Indicators. Annexes IV-1, IV-2, and IV-3 present appropriate indicators that can be used at the manager level to evaluate transmission, distribution, and substations. Exhibits IV-1, IV-2, and IV-3 provide the following information about each of these indicators:

- How the performance indicator assists in measuring the achievement of objectives.

- Why the performance indicator is important. This includes a discussion of what the performance indicator measures, how the performance measures are calculated, and the level to which the performance indicator should be addressed.

Appendix IV-A provides additional discussion of each of these three exhibits.

To involve all ranks in the achievement of the utility's overall objectives, performance indicators should be identified for all levels of the utility.

Transmission and Distribution General Manager Performance Indicators. To evaluate the overall effectiveness of T&D activities, the T&D general manager should regularly discuss with his departmental manager's their key indicators. The T&D general manager must also have information that will assist in managing and controlling overall T&D activities. Annex IV-4 presents the T&D general manager's performance indicators.

Chief Executive Performance Indicators. The Chief Executive is primarily concerned with the guidance of his managers in matters having long-term impact on the utility. Assistance in this task is provided by the set of performance indicators listed in Annex IV-5 which can be instrumental in identifying trends and anomalous events.

DEVELOPING THE PERFORMANCE INDICATOR DATA BASE AND REPORTING REQUIREMENTS

The generic discussion in Chapter II is applied to T&D activities in Exhibits IV-1, IV-2, and IV-3--which detail the data needed to compute a selection of T&D performance indicators.
IDENTIFYING POSSIBLE COST-EFFECTIVE IMPROVEMENTS AND DEVELOPING ACTION PLANS TO ACHIEVE THEM

The case studies presented in Appendix IV-C illustrate how this element is applied to the T&D function. 1/ Two components of the critical performance indicators—transmission circuit interruptions and distribution transformer losses 2/—have been selected to show how the three steps involved in this element would be performed.

The case studies assume various figures and operating conditions for the hypothetical utility to demonstrate more effectively how the PI/MRS process can be used to identify and achieve cost economies. The assumptions (as well as the analysis of the figures in the PI/MRS process) are based on experience with several power utilities.

In order to permit the method of analysis that uses comparative figures from other utilities, Appendix IV-D presents the results of Ernst & Whinney's survey of U.S. and international utilities. This survey only identified one T&D-related performance indicator system loss. To reflect the actual operating experience of utilities in the comparative figures used in the case studies, figures obtained from actual utility experience are used. As noted in Chapter II, however, comparative performance indicators must be used with care; so the Chapter II discussion of comparative indicators should be digested before proceeding with the case study examples.

DEVELOPING REPORTING DOCUMENTS TO (1) MONITOR THE COST-EFFECTIVE IMPROVEMENT PLANS AND (2) PROVIDE MANAGEMENT WITH INFORMATION ESSENTIAL FOR MANAGING UTILITY OPERATIONS

The transmission interruption study will be used as an example of how this element is applied to T&D activities. The case study is presented by month to show how reporting documents are developed.

Month One, Year One. At this time, the hypothetical utility is preparing annual plans and budgets. No acceptable performance level has been established for transmission interruptions.

The current interruption level is 5.6 per 100 circuit km. To complete its annual plans and budgets, the hypothetical utility applies an abbreviated version of the PI/MRS and develops an initial action plan (this is

1/ The case studies are intended only to demonstrate the PI/MRS process—they do not present the detailed, comprehensive analysis that would be part of a utility's actual PI/MRS activities.

2/ Appendix IV-B provides additional information (but not case studies) to assist in applying the PI/MRS process to the other critical T&D performance indicators.
based on performing Steps 1, 2, and 3 in Phase II) that sets the following objectives:

- Improve transmission circuit interruption level by instituting a system-wide inspection and maintenance program. Targets for the first three years are 3.7, 3.4 and 3.1 interruptions per 100 circuit km.

- Realize first year net benefits of approximately $25,000 ($41,000 less $16,000) and net benefits of approximately $69,500 and $97,000 for years two and three.

This information is incorporated in the annual budget (initial savings of $25,000 for the upcoming year).

Month Two, Year One. Although first-year progress in reducing interruptions from 5.6 to 3.7 would, in practice, be intermittent rather than steady, the assumption for this case study is that both interruptions and expenditures related to the program decline progressively during year one.

The target for the end of month two is 5.3 interruptions (with associated net benefits of $6,800) with an acceptable deviation of 0.20. Actual results of the period indicate that 5.0 is achieved, producing an additional $6,800 net cost reduction (for a total reduction of $13,600). These better-than-anticipated results trigger an exception report, which ensures that the accelerated decline in interruptions is properly monitored. Despite these results the utility feels the year-end target of 3.7 will not be bettered. These figures are shown in Exhibit IV-4.

Remaining Months of Year One. The action plan is incorporated in plans and budgets for the next year in Month 12, Year One. Thus, the first month that new, current data would be produced for the action plan reporting document, would be Month Two, Year Two.

Month Two, Year Two. The first-year target of 3.7 was achieved, so the year two target of 3.4 is formally adopted. Again, the progress toward targets and net benefits is assumed to be steady throughout the year. The Update of Current Status and the Revised Long-Term Estimate are presented in Exhibit IV-5, which provides the following information:

- Update of Current Status - The current planned result of 3.6 has been exceeded by 0.1 to 3.5. An exception report is not triggered in this case. The better-than-planned result produces net benefits $1,000 greater than the planned monthly benefit of $5,800.

- Revised Long-Term Estimate - For various reasons, utility analysts determine that the year-end target of 3.4 can be exceeded by .1, to 3.3. This will increase net benefits from $69,500 in the original plan to $83,250. A revised action plan and exception report are not required.
This information should be included in a report that incorporates information from all action plans produced by managers reporting to the T&D general manager.

INTEGRATING THE PI/MRS PROCESS WITH THE PLANNING AND BUDGETING CYCLE TO PROVIDE INCENTIVE FOR FULL ACHIEVEMENT OF COST EFFECTIVE IMPROVEMENTS

The generic discussion in Chapter II and the case study of reporting documents provide the necessary information to apply this element to T&D operations. Important aspects of this element are:

- The PI/MRS process can make the planning and budgeting cycle a useful exercise for promoting cost effective improvements.
- All performance indicators should be revised in the planning and budgeting cycle.
- Annual cost revisions noted on the performance indicator reporting document should be used in preparing the annual budget.
- Continuing reviews should be undertaken to focus on future cost savings.

INTEGRATING THE PI/MRS PROCESS INTO THE HUMAN RESOURCE ASPECTS OF THE UTILITY

The following text repeats what was said in Volume II on the subject so that this volume is self contained. Employees throughout the utility will be responsible for implementing the action plans derived from the PI/MRS process. These employees must therefore receive information and be consulted in its interpretation. This is especially true for non-management personnel.

The human resource aspects of the PI/MRS process are:

- Employee understanding of PI/MRS process
- A participatory management approach
- Performance evaluation
- Rewards
- Clear communication from upper management
- Training designed to support the action plans

Employee Understanding of PI/MRS Process. Any management process, whether new or existing, must be understood by those involved in its execution and must be perceived to be a benefit to them. If employees are represented
by organized labor, union officers must be fully educated in the PI/MRS process. Employees will make an effort to ensure maximum benefits of the process only when they fully understand it. Furthermore, PI/MRS objectives must be described clearly so that both upper and lower management are familiar with its objectives. One way to encourage understanding of the system is to conduct training courses (open to management and non-management employees) in the use of the process.

**Participatory Management Approach.** The PI/MRS is structured as a top-down management approach, under which senior management (1) sets corporate and operating objectives and (2) works with middle management to identify performance indicators that measure these objectives. The identification of cost-effective improvements, as well as identification of performance indicator targets, however, often works most effectively when the process starts at lower management or non-management levels and works its way up (within certain limitations) in a bottom-up approach. This more effectively motivates employees to do a good job, because they initiate and own the process. For example, lower-level employees identify improvements and set targets. They then pass these to the next higher level of supervision or management for approval or revision. Experience shows that the improvement targets prompted by employees in a participatory process will often be higher and better defined (and more achievable) than when supervisors and upper management dictate the targets. This manual does not attempt to repeat the exhaustive and documented research on the benefits of a participatory management approach, but simply points out the potential advantages of the approach in achieving full benefits of the PI/MRS process.

**Performance Evaluation.** Performance evaluations are used to reinforce proper use of the PI/MRS process. Management and non-management performance evaluations are linked to achieving performance targets over which the individual has control. The links must be established carefully and precisely, so that employees do not feel that their performance evaluation is based only on figures accumulated. If done correctly, such links help keep personal biases from entering into the evaluation process. Performance evaluations linked to appropriate performance indicators and targets will help employees understand that achieving targets will result in more favorable evaluations, encouraging work that promotes the overall objectives of the utility.

**Rewards.** It is important for employees to receive recognition when they have achieved personal objectives measured in the performance evaluations. The form of the recognition must be based on the utility's particular social culture and business environment and depend on the nature and magnitude of the utility's benefit from employee performance.

**Clear Communication from Upper Management.** Upper management must ensure that all employees fully understand the importance of cost economy by clearly and consistently reminding employees of the value of cost economy. Further, upper management must communicate overall objectives to employees and point out that these objectives are fostered through the PI/MRS process.
Training Designed to Support the Action Plans. Initial employee training in the PI/MRS process should be followed by periodic reviews to reinforce initial training. Based on these reviews, supplementary training should be given as necessary.
### MENU OF PERFORMANCE INDICATORS
#### FOR TRANSMISSION MANAGERS

**Objective:** Provide reliable service

**Transmission System**

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<tr>
<td>1.</td>
<td>Number of interruptions ( \times 100 ) (at each prevailing voltage level)</td>
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<td></td>
<td>Circuit km</td>
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<tr>
<td>2.</td>
<td>Average duration of transmission line interruption (by class).</td>
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<tr>
<td>3.</td>
<td>Annual load loss (MW) caused by transmission interruptions</td>
</tr>
<tr>
<td></td>
<td>System peak load</td>
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<tr>
<td>4.</td>
<td>Annual unserved energy (MWh) caused by transmission interruptions</td>
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<td></td>
<td>Total energy generated</td>
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<tr>
<td>5.</td>
<td>Number of overloaded circuit occurrences ( \times 100 ) (at each prevailing voltage level)</td>
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<tr>
<td>6.</td>
<td>Annual number interruptions associated with switching mal-operation</td>
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<td>Total number of interruptions</td>
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**Objective:** Maximize efficiency

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<td>7.</td>
<td>Transmission maintenance hours</td>
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<td></td>
<td>Transmission circuit km</td>
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<td>8.</td>
<td>Labor-related O&amp;M costs (including transmission substations)</td>
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<td>Total revenues</td>
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<td>9.</td>
<td>Material-related O&amp;M costs (including transmission substations)</td>
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<td></td>
<td>Total revenues</td>
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<tr>
<td>10.</td>
<td>FTE ( ^1/ ) (by category) transmission staff numbers</td>
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<td>Transmission circuit km</td>
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<tr>
<td>11.</td>
<td>Number of occurrences that constrained economical generation because of limited transmission capabilities</td>
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<td>12.</td>
<td>Number of occurrences that inter-utility energy sales and purchases are constrained by transmission</td>
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<td>13.</td>
<td>Average energy (MWh) losses ( \times 100 ) (at each voltage level) ( ^2/ )</td>
</tr>
<tr>
<td></td>
<td>Circuit km</td>
</tr>
</tbody>
</table>

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\(^1/\) Full-Time Equivalent employees categorized as management, skilled workers, unskilled workers, and support staff.

\(^2/\) Energy losses over time are defined in MWh.
MENU OF PERFORMANCE INDICATORS
FOR SUBSTATION MANAGER

Objective: Provide reliable service

Substation

1. Number of transformer failures . 100 (by class).
   Transformers on system

2. Average duration of transformer outage (by class).

3. Annual load loss due to transformer failures (MW)
   System peak load (MW)

4. Annual unserved energy (MWh) due to transformer failures
   Total energy generated (MWh)

5. Number of overloaded transformer occurrences . 100 (by class)
   Total number of transformers

6. Number of major equipment failures (i.e., capacitors, reactors, circuit breakers) . 100
   Total number of installed equipment

7. Annual number of voltage exception reports . 100 (by class, i.e.
   Total number of substations transmission and distribution)

Objective: Maximize efficiency

8. Substation maintenance hours (by class, i.e.
   Substation MVA transmission and distribution)

9. Average life (years) of substation transformers (by class, i.e. transmission, distribution, size).

10. FTE 1/ (by category) substation staff numbers
    Total substation MVA

11. Average energy (MWh) losses (by class, i.e.
    MVA of substation capacity transmission and distribution)

1/ Full-Time Equivalent employees categorized as management, skilled workers, unskilled workers, and support staff.
MENU OF PERFORMANCE INDICATORS FOR DISTRIBUTION MANAGER

Objective: Provide reliable service

Distribution System

1. Number of interruptions . 100 (at each prevailing voltage Circuit km level and by class)

2. Average duration of distribution line interruption (by class).

3. Annual load loss (MW) caused by distribution interruptions System peak load (MW)

4. Annual unserved energy (MWh) caused by distribution interruptions Total energy generated (MWh)

5. Number of overloaded feeder occurrences . 100 Circuit km

Objective: Maximize efficiency

6. Distribution maintenance hours . 100 Distribution circuit km

7. Labor-related O&M costs (including distribution substations) Total revenues

8. Material-related O&M costs (including distribution substations) Total revenues

9. FTE 1/ (by category) distribution staff numbers . 100 Total distribution circuit km

10. Average energy (MWh) losses . 100 (at each voltage Circuit km level)

1/ Full-Time Equivalent employees categorized as management, skilled workers, unskilled workers, and support staff.
T&D GENERAL MANAGER
PERFORMANCE INDICATORS

Objective: Provide reliable service

1. **Number of transmission circuit interruptions** . 100 (at each prevailing Circuit km voltage level)

2. Average duration of a transmission line outage.

3. **Annual unserved energy (MWh) caused by transmission outages**

4. **Number of transformer failures** . 100 (by class) Transformers on system

5. Average duration of transformer outages.

6. **Annual unserved energy (MWh) caused by transformer failures**

7. **Number of distribution circuit interruptions** . 100 (at each prevailing Circuit km voltage level)

8. Average duration of a distribution line outage.

9. **Annual unserved energy (MWh) caused by distribution outages**

Objective: Maximize efficiency

10. **Labor and material-related transmission O&M costs**

11. **Transmission FTE staff numbers** . 100 Transmission circuit km

12. Number of occurrences that limited transmission outlets constrained economical generation.

13. **Transformer FTE staff numbers** Substation MVA

14. **Labor and material-related distribution O&M costs**

15. **Distribution FTE staff numbers** . 100 Distribution circuit km

Total revenues
16. Average power losses (MW) \[ \frac{100}{(at \ each \ voltage \ Circuit \ km \ level)} \]

17. Average power (MW) losses (by class) MVA of substation capacity

Objective: Management control of T&D activities

18. Listing of all major changes and variances in any of the performance measures monitored by T&D managers. 1/

1/ Include measurement against certain targets, discussed later in this chapter.
CHIEF EXECUTIVE
T&D PERFORMANCE INDICATORS

Objective: Ensure that the utility is achieving its overall goals and objectives by providing guidance in those T&D areas having major impact on utility

1. Number of T&D circuit interruptions . 100 (by voltage level)
   Circuit km

2. Number of transformer failures . 100 (by class)
   Transformers on system

3. Total unserved outages energy (MWh) caused by all outages
   Total energy generated

4. Total T&D labor and material-related O&M costs
   Total revenues

5. Total T&D FTE staff numbers
   Total energy generated (MWh)

6. Number of occurrences in which limited transmission outlets constrained economical generation.

7. Transmission, substation, and distribution losses (MWh) . 100
   Total net energy generated

8. Aggregate indicators for entire utility that include the T&D function. 1/

   Objective: Overall management control of utility

9. Listing of all major changes and variances in any of the T&D general manager performance measures. 2/

1/ The executive general manager will also receive aggregate information on staffing years per customer, overall O&M cost per kWh, and other indicators.

2/ Including measurement against certain targets, discussed later in this chapter.
TRANSMISSION SYSTEM PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide reliable service

IV.1.1. Number of interruptions per 100 circuit km at each prevailing voltage level

This indicator, which should be calculated for each prevailing voltage level, does not necessarily imply reliable or unreliable service to the customer. With multiple transmission paths that permit flexibility of control by system operator, transmission outages can occur with no loss of service to the customer. This indicator, however, provides a measure of the potential for the most serious type of outage—transmission-related outages that affect large areas. The data necessary to calculate this indicator are obtained from the counters on the protective relaying equipment on each transmission line. Each voltage class should be totaled individually so that the total number of interruptions during the period can be divided by the number of transmission circuit kilometers in each voltage class. The result is multiplied by 100 to place the indicator on a per 100 circuit km basis.

IV.1.2. Average duration of transmission line interruption (by class)

This indicator provides a measure of the seriousness of outages by class of circuit, averaged over an appropriate period. It can also assist in measuring the level of damage inflicted on the circuit, the efficiency of work crews, the availability of spare parts (such as towers), or a combination of these things. The sources of outage duration data are the automated data logs in the system control center, provided the transmission lines telemeter data back to the control center. If not, calculation of this indicator requires that each transmission line outage be established on the basis of relay operation and customer no-light reports. This is not an exact procedure, but if all known interruptions and complaints can be related to individual lines, a useful approximation can be obtained. Once the interruptions are all assigned to an individual line, the individual outage durations should be determined using actual or estimated data. With this data, total interruptions and total duration of outages can be determined for each line. This indicator is obtained by dividing duration by number of interruptions for each class of line.

IV.1.3. Annual load loss (MW) caused by transmission line interruption

This indicator that actually measures reliability to the customer that was not present in the first indicator is provided here. These losses, however, can result from single or multiple circuit failures. This indicator measures the magnitude of the outages, not the frequency of duration of the outages. Obtaining load loss data is not a simple process. Each circuit—based on recording watt-hour readings at the substation—should be assigned an average MW loading. (This loading can be varied by season if sufficient data exists.) The total number of the circuit outages is available from the data needed for the previous indicator. If this is multiplied by the average loading for each circuit, a MW total load loss is produced. This is divided by the system peak load.
IV.1.4. Annual unserved energy (MWh) caused by transmission interruptions

This indicator provides the duration component of outages that was omitted in indicator IV.1.3. It provides perhaps the best overall single indicator of customer service reliability. In addition to data used in the previous indicator, duration data is required for each circuit available from the second indicator. The total number of circuit outages is multiplied by average loading and average duration to estimate the MWh not supplied on each circuit during the period. Figures for all circuits are added to produce the total annual MWh not supplied. Care must be taken to avoid double counting those transmission circuits that feed other circuits.

IV.1.5. Number of overloaded circuit occurrences per 100 circuit km at each prevailing voltage level

Before a gradually increasing load creates serious problems, usually there are signs such as an increase in the number of overloaded circuits. Utility managers must be aware of such signals. This indicator provides the needed warning. Overloads should be categorized as (1) those beyond the normal, 24-hour loading limit of the line, (2) those beyond the Long-Time-Emergency (LTE), 6 to 12 hour limit of the line and (3) those beyond the Short-Time-Emergency (STE), 3 hour limit of the line. Overloads in the STE category require immediate attention. This indicator should be categorized by voltage level. The data for this indicator are available directly from the "push up" type maximum demand pointer or from the recording meter chart. Both of these devices are located on each circuit at the substation. The maximum loading MW can be tabulated and categorized on the basis of voltage and 100 circuit km.

IV.1.6. Annual number of interruptions associated with switching mal-operations

This indicator, which measures the number of outages due to switching mal-operation, reflects outages caused by malfunctioning of the system protection scheme. While this indicator may not be necessary in all systems, it can prove very informative in systems with limited transmission and complex protection schemes. Past experience in the United States indicates that large, cascading-type outages have most often resulted from an improbable series of events combined with a malfunction of the system protection scheme. This indicator enables utility managers to determine the degree to which system protection schemes are depended on to give reliable system operations. If this indicator shows high values, the utility may be too dependent on such schemes and might consider building additional paths. Data concerning switching mal-operations that produce outages should be recorded in the system operator's log. The numbers of these events can be totaled and then compared with the total number of outages derived in determining indicator IV.1.1.
Objective: Maximize efficiency

1.7. Transmission maintenance hours
Transmission circuit km

is gauge of maintenance activity and effectiveness may be most useful, when examined over time, as a guide to establishing minimum maintenance standards. The source of the transmission maintenance hours is the time sheets of the overhead lines employees, which should be structured to show total time devoted to transmission circuit maintenance. This total is then divided by the total system transmission circuit kilometers, to produce the indicator.

V.1.8. Labor-related O&M costs (including transmission substations)
Total revenues

This indicator provides a measure of labor-related costs for budgeting purposes. When this indicator is examined over time (corrected for inflation), it can indicate shifts of labor expenses and efficiency changes. From the budget report, all transmission costs should be segregated into two categories: The first, labor-related costs, is used for this indicator. The second, material-related costs, is used for the next indicator. Labor-related costs are expressed as a proportion of total utility revenues.

IV.1.9. Material-related O&M costs (including transmission substations)
Total revenues

This indicator is derived by the same method as used for the previous indicator. Material-related costs are expressed as a proportion of total utility revenues.

IV.1.10. Full-time equivalent employees (FTE) transmission staffing years (by category)
Transmission circuit km

This indicator measures changes in the number of transmission-area employees as the utility's system develops. It differs from the first indicator in this section because it includes both operations and maintenance hours. It can also be used to compare changes in budgeting and cost allocation practices of various utility departments over time. The FTE totals should be segregated at the lowest level by categories such as management, skilled workers, unskilled workers, and support staff. The source of this data is time allocation reports completed by transmission-area employees. Hours worked are totaled and divided by normal working hours in period 1/ to produce full time equivalents.

1/ 2,000 hours is often used as the effective total regular working hours per annum not counting overtime, weekends and holidays.
IV.1.11. Number of occurrences that constrained economical generation because of limited transmission capabilities

This indicator measures how often transmission limitations prevent the utility from using its most economical generation. Efficiency is compromised if installed transmission is inadequate or circuit interruptions are so frequent that the most economical generation configuration cannot be used. 1/ Only a few days of generation restrictions are sufficient to justify correcting the transmission constraint. Using this indicator, economic studies should be conducted to determine the cost of the "unavailable" generation. Any instance of economical generation being constrained by transmission should be noted in the system dispatcher's log. To produce this indicator, the number of such events is totaled for a given period.

IV.1.12. Number of occurrences that inter-utility energy sales and purchases are constrained by transmission

This indicator measures how often transmission limitations prevent the utility from making inter-utility energy sales or purchases. Off-system generation and load can be viewed as a special case of native system parameters. When economical generation and load can be viewed as special case of native system parameters. When economical and/or emergency off-system sales are constrained by limited transmission--efficiency and reliability suffer. The extent to which this affects a utility's system operation is critical. This indicator merits special attention to determine if detailed data is required to perform economical transfer studies. (See also discussion on SCADA system requirements in this chapter.) The data required here is similar to that for the previous indicator, except that it deals with interchange transaction constraints.

IV.1.13. Average Energy (MWh) losses per 100 circuit km by each voltage level

This indicator measures the extent of losses normalized by the amount of circuit line at each voltage level. These losses are expressed in MWh. Although transmission line losses are factored into the generation economic dispatch program, circuit reconfiguration may be an acceptable alternative for reducing high loading levels and therefore high \( I^2R \) losses. This indicator can be determined by actual measurements or through simulation studies. The data to evaluate losses for various transmission configurations can best be obtained by running a power flow computer program, which models the candidate transmission system. Loss levels are a direct output of the power flow and can thus be readily compared. The existing system losses can be established by measuring the difference between generated MWh and MWh metered at all of the distribution substations. The modeled losses and the actual losses can then be compared on the basis of circuit km.

1/ The economical generation dispatch program should consider the effect of transmission line losses under various circuit and load-level configurations. This is commonly achieved by using a "B-coefficient, loss formula" program.
SUBSTATION PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide reliable service

Performance Indicator

IV.2.1 Number of transformer failures per 100 transformers on the system (by class)

This indicator provides a good measure of the reliability of this key system component. For transmission transformers (e.g. at voltages 230-138 kV, 138-59 kV, 69-25 kV), loss of a transformer does not necessarily cause loss of service because transmission substations usually include multiple transformers or the supply can be made from another source. The indicator is nonetheless still important, however, because these transformers are expensive and have long installation lead times. This indicator also provides a measure of service reliability, because customers frequently lose service when a distribution transformer fails. The number and class of transformer failures in a given period is available from substation and distribution work order files. The total number of transformers installed by class is available from property accounting records.

IV.2.2 Average duration (hours) of transformer failures (by class)

This indicator measures the length of service interruptions of transformers due to failure and is most significant for transmission transformers. Interruptions of these transformers tend to be lengthy, and spare transformers may not be available. Replacements for distribution transformers, on the other hand, are usually available from stock or can be obtained quickly. For transmission transformers, the average failure duration is the time from failure to repair or replacement. This interval should be recorded on the work order that covers the change as part of the completion documentation. The duration of outages is then averaged for the year.

IV.2.3 Annual load loss (MW) caused by transformer failures

\[
\text{System peak load (MW)}
\]

This indicator is a measure of the overall system unreliability caused by transformer failures. Combined with Indicator IV.2.1 (frequency) and Indicator IV.2.2 (duration), the three key components of reliability, magnitude, frequency and duration are measured. For each class of transformer, the average MW loading level should be established. This MW total for all transformer failures should then be established with the indicator calculated as a proportion of total annual system peak.

IV.2.4 Annual unserved energy (MWh) caused by transformer failures

\[
\text{Total energy generated (MWh)}
\]

This indicator, which expresses both the magnitude and duration components of reliability, provides the best single measure for identifying opportunities for improvement. Distribution transformer failures should be carefully documented. This indicator adds duration to the calculation provided by Indicator IV.2.3 above: duration (hours) times MW equals MWh. This yields an annual MWh data comparison.
IV.2.5. Number of overloaded transformer occurrences per total number of transformers (by class)

This indicator measures overloaded transformer occurrences. It is computed by dividing the number of occurrences by the number of transformers. While transformers can generally withstand significant overloads, these occurrences should be carefully noted for loss-of-life and failure. Rating transformers by using the three category systems; i.e., normal, LTE, STE (see overloaded transmission discussion), provides monitoring sufficient to gauge the severity of overloads. This indicator will apply best to transmission-level transformers, because most distribution transformers will not be monitored. Data for this indicator is available from the substation metering devices, which show maximum MW demand on substation transformers. These loading levels can then be categorized. For distribution transformer overloads, a transformer load management program is required for projecting accurate results that can be categorized.

IV.2.6. Number of major equipment failures (i.e., capacitors, conductors, circuit breakers)

This indicator measures the availability of major equipment and provides a guide for decisions to stockpile this equipment or have system spares available. The data source for substation equipment failures are the equipment history cards (or computerized substation maintenance history data base) maintained for each piece of substation equipment. As equipment fails and must be replaced, the equipment cards should be pulled, counted, and categorized. Total installed equipment by category can also be determined by the total number of cards.

IV.2.7. Annual number of voltage exception reports per 100 of total number of substations by class (i.e., transmission and distribution)

This indicator assists in efforts to maintain adequate quality of customer service. Voltage exception reports are produced as a result of significant voltage excursion (more than plus or minus 10%). When exception reports are significant, as reflected either in trends or in absolute measurements, some action to restore normal voltage class by providing area reinforcements is called for. Voltage exception reports must be available as a basis for this indicator. Usually the basis for these reports is a recording voltmeter, located within the substation. If customers repeatedly complain about low voltage, it is often appropriate to hang recording voltmeters at the customer service connection to determine the true voltage fluctuation.

IV.2.8. Substation maintenance hours

This indicator should measure a fairly consistent level of maintenance activity over time. It should be more consistent than the transmission maintenance indicator due to greater physical or environmental exposure of the transmission lines. Substation maintenance man-hours can be derived from the substation personnel time reports. Substation MVA ratings are available from substation equipment files. Usually voltages can be categorized as distribution at 15 kV and below, and as transmission, at more than 15 kV. Maintenance man-hours must be similarly categorized before calculating this indicator.
IV.2.9. **Average life of substation transformers by class (i.e., transmission and distribution)**

This indicator provides a measure of transformer life and allows the manager to prepare for replacement in the regular budgeting cycle and to integrate his department's efforts with those of the planning department in the areas of capital improvements and system expansion. Substation transformer average life data is available from either property accounting records or the substation equipment history cards mentioned earlier. Voltage class and size information should also be available from these sources.

IV.2.10. **Full-time equivalent employees (FTE) substation staff numbers**

\[
\frac{\text{Total Substation MVA}}{\text{FTE}}
\]

This indicator measures substation staffing normalized by substation MVA. As the system grows, it is reasonable to assume that more personnel will be required to do the work. An indicator covering substation O&M is useful for budgeting. Substation O&M man-hours worked during the period are available from substation personnel time reports. The total O&M man-hours worked during the period should be divided by normal working hours in the period to produce FTE. The total substation installed MVA, available from property accounting, is then divided by FTE to yield this indicator.

IV.2.11. **Average energy (MW) losses per MVA of substation capacity by class (i.e., transmission and distribution)**

This indicator measures transformer losses normalized by MVA of substation capacity. To restrain operating costs, transformer losses should be minimized, because every lost MW that is prevented is one less MW that must be provided. This indicator will allow for precise, periodic transformer loss analyses that may point to economical replacement and early retirement of older transformers. The average power (MW) losses are calculated in the same way as discussed previously for the performance indicator: Average Power (MW) Losses per 100 Circuit km, Exhibit IV-1.
DISTRIBUTION SYSTEM PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide reliable service

Performance Indicator

IV.3.1. **Number of interruptions per 100 circuit km at each prevailing voltage level**

This key indicator quantifies the frequency of interruptions on the distribution system, which usually result in customer outages. Circuit interruption data is available at the substation on the counters for protective relay breaker operation and emergency service reports. The total number of distribution circuit interruptions is then divided by the total number of 100 distribution circuit kilometers. Distribution circuit km are available from property accounting or can be scaled from feeder maps.

IV.3.2. **Average duration of distribution line interruptions (by class)**

This indicator measures the effects of an average outage on the distribution system. It quantifies the effects of damage to the circuit, the efficiency of work crews, the availability of stocked parts, or some combination of these three factors. Distribution circuit outage data can be obtained in part from telemetry information at the substation that shows breaker position. If telemetry is not available, then customer outage reports should be used to estimate the total number of outages and the duration of each circuit outage. Average duration can then be calculated.

IV.3.3. **Annual load loss (MW) caused by distribution interruptions**

\[
\frac{\text{System peak load (MW)}}{\text{Annual load loss (MW)}}
\]

This indicator measures the magnitude of component reliability, complements the frequency component (number 1 above). Each instance of load loss will be estimated over the year, totaled, and then divided by the one-time system peak load. Average MW loading levels of each feeder should be estimated using data from substation metering on the feeder. The average MW level is then multiplied by the number of outages of that feeder (from data assembled for the previous indicator). This total MW data is then compared as a percentage with annual system peak load.

IV.3.4. **Annual unserved energy (MWh) caused by distribution interruptions**

\[
\frac{\text{Total energy generated (MWh)}}{\text{Annual unserved energy (MWh)}}
\]

This is the best overall single indicator of customer service reliability of the distribution system because it combines the magnitude and duration components of reliability. Outages can significantly affect this index only if their size and length is substantial. This calculation combines the number of hours that each circuit is out (from previous indicator) to produce total unserved MWh. This total is then compared with total energy generated.
IV.3.5. Number of overloaded feeder occurrences per 100 circuit km

This indicator warns of impending problems, permitting an action plan to be developed and implemented before customer service is affected. This indicator is important because: (1) it can detect potential customer service interruption and (2) if the problem is identified before supply is interrupted, it provides time for preventive maintenance—which is preferable and allows better work quality to be applied and expenses can be optimized. Feeder overload data is obtained by comparing the actual distribution circuit MW loading (available on substation charts or indicating meters) with the established feeder MW rating. The number of overload occurrences is counted and divided by the number of 100 distribution circuit km.

Objective: Maximize efficiency

IV.3.6. Distribution maintenance hours

This indicator, which shows the average number of distribution man-hours applied per 100 circuit km during the time span of measurement, is probably most useful in establishing minimum levels of distribution maintenance over time. Distribution maintenance hours can be derived from distribution personnel time records. The total of these hours is then divided by total distribution circuit km.

IV.3.7. Labor-related O&M costs (including distribution substations)

This indicator shows labor-related O&M costs as a proportion of revenues. It is useful for budgeting, because it permits comparison over time (when inflation is considered) and shifts (either pre-planned or accidental) in the size of the labor force, wage rates, or efficiency. The data required and calculation method used for this indicator are the same as those for the similar indicator in the transmission category.

IV.3.8. Material-related O&M costs (including distribution substations)

This indicator is important for much the same reason as are labor-related O&M costs (discussed in Number 2 above). The data required and calculation method used for this indicator are the same as those for the similar indicator in the transmission category.

IV.3.9. Full-time equivalent employee (FTE) distribution staffing years

This indicator measures staffing levels when the FTE figures are categorized as, for example, management, skilled workers, unskilled workers, and support staff. As a utility's distribution system develops and matures, it is reasonable to assume that more effort (i.e., man-hours) will be required to maintain reliable and efficient performance. The data required and calculation method used for this indicator are the same as those for the similar indicator in the transmission category.
EXHIBIT IV-3
Page 3 of 3

IV.3.10. Average energy losses (MW) per 100 circuit km

Engineering related distribution line losses should be minimized to reduce unnecessary generation. This indicator measures these losses and normalizes them by circuit km. Trends and absolute values revealed in this indicator should lead to economic conductor sizing studies, with reconductoring performed where savings are shown to exceed costs. Calculation of this indicator is based on an engineering estimate of average power losses provided when the feeder is designed. Based on these estimates, each feeder can be assigned a MW loss estimate based on average loading levels. The total MW of anticipated loss can be added and then divided by distribution circuit km divided by 100 to yield this indicator.
### PERFORMANCE INDICATOR REPORTING DOCUMENT
FOR TRANSMISSION CIRCUIT INTERRUPTIONS

**Date:** Month Two, Year One  
**Department:** T&D General Manager

<table>
<thead>
<tr>
<th>Transmission circuit interruptions</th>
<th>Performance indicator #2, #3, etc.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current reporting information</td>
<td></td>
</tr>
<tr>
<td>- Current operating level</td>
<td>5.0</td>
</tr>
<tr>
<td>- Current target</td>
<td>5.3</td>
</tr>
<tr>
<td>- Acceptable deviation</td>
<td>0.2</td>
</tr>
<tr>
<td>- Actual deviation</td>
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<tr>
<td>- Exception report needed</td>
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<tr>
<td>- Gain (loss) in net benefits for</td>
<td>$6,800</td>
</tr>
<tr>
<td>period</td>
<td></td>
</tr>
</tbody>
</table>

### Year-end reporting information

| - Originally planned target        | 3.7                                 |
| - Acceptable deviation             | 0.2                                 |
| - Revised targets                  | None                                |
| - Exception report needed          | No                                  |
| - Gain (loss) in net benefits for  | 0                                   |
|   period                           |                                     |
# ACTION PLAN REPORTING DOCUMENT  
FOR TRANSMISSION CIRCUIT INTERRUPTIONS

<table>
<thead>
<tr>
<th>Date:</th>
<th>Action plan</th>
<th>Action plan</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Month Two, Year Two</td>
<td>#1</td>
<td>#2</td>
<td>#3, etc.</td>
</tr>
<tr>
<td>Department:</td>
<td>T&amp;D General Manager</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

## I. Description of action plan

1. Improve transmission circuit interruption level by increased inspection and maintenance

## II. Initial estimates

- **Targets**: 3.4, year-end
- **Annual net benefits**: $69,500

## III. Update of current status

- **Targets**
  - **Current planned**: 3.6
  - **Acceptable deviation**: 1
  - **Current actual**: 3.5
  - **Current difference**: 1
- **Estimated net benefits**
  - **Current planned**: $5,800
  - **Current actual**: $6,800
  - **Current difference**: $1,000
- **Exception report needed**: No

## IV. Revised long-term estimate

- **Targets**
  - **Long-term originally planned**: 3.4
  - **Acceptable deviation**: 1
  - **Long-term now expected**: 3.3
  - **Long-term expected difference**: .1
- **Annual net benefits**
  - **Long-term originally planned**: $69,500
  - **Long-term now expected**: $83,250
  - **Long-term difference**: $13,750
- **Revised actual plan necessary**: No
- **Exception report needed**: No
DISCUSSION OF TRANSMISSION AND DISTRIBUTION PERFORMANCE INDICATORS

INTRODUCTION

This appendix provides additional information on transmission and distribution activities—including transmission operation and maintenance, substation operation and maintenance, and distribution operation and maintenance. Related objectives and performance indicators are summarized in Exhibits IV-1, IV-2, and IV-3 (Chapter IV).

TRANSMISSION OPERATION AND MAINTENANCE

The primary function of transmission is to carry electric power from the point of generation to the point where it enters the distribution system. This function must be completed economically and reliably with minimal circuit interruptions and losses.

Transmission operation is affected by individual line loading, which is determined by the on-shift dispatchers within the system operation function, but providing a transmission system that can be successfully operated, is a responsibility of the transmission manager. The transmission manager is therefore required to correct operating problems that cause circuits to be unavailable and to control costs by effective use of labor resources.

Periodic transmission maintenance is required to identify potential operating problems and to keep the transmission system available. For operating performance objectives to be met, maintenance hours must be allocated cost effectively: neither too much nor too little.

Performance indicators identified in Exhibit IV-1 can assist the transmission manager in judging whether there is room for improvement.

SUBSTATION OPERATION AND MAINTENANCE

Substation plant within the T&D function includes the transformation and switching facilities required to step up and step down voltage and to provide circuit switching and protection.

Substation operation is also directed by system operating personnel, who set switch positions and determine which capacitors, transformers, and reactors to place in service. The substation manager is responsible for following specific operating directives issued by system operations and for having personnel available to carry out these instructions. The objective is to have sufficient substation personnel to handle peak operations and to keep them busy with inspection and maintenance activities during off-peak periods.

Substation maintenance serves to keep all substation equipment available for service when needed. This requires detailed inspection at least
once each week guided by a predetermined check list for each substation. A thorough preventive maintenance program is also required. Although cost-control is important, the substation manager's prime objective must be to provide reliable service the cost of which reflects the high costs incurred when major transformers or switches are out of service or are operating inefficiently.

Performance indicators identified in Exhibit IV-2 can assist the substation manager in judging whether there is room for improvement.

**DISTRIBUTION OPERATION AND MAINTENANCE**

The distribution installations comprise all circuits and equipment that distribute power from the substation to the consumer. Circuits, transformers, fuses, and switches are all most numerous in plant that falls within the distribution area. The primary obligation of distribution activity is to provide adequate and reliable electric service of good quality to the consumer.

Distribution operation and maintenance are directed at keeping distribution equipment in good condition so that interruptions in service are infrequent and brief, customer inconvenience is minimized, and utility revenues are maximized. Restoration of electric supply following an outage is therefore a vital distribution activity. Because distribution equipment is the most remote and scattered of any in the electric system, outages can be caused by a variety of factors. Restoration can require many man-hours of work by distribution employees but is essential for providing quality electric service. Nonetheless, because distribution labor and material expenses tend to be proportionately high, they should be tightly controlled.

Performance indicators listed in Exhibit IV-3 can assist the distribution manager in judging whether there is room for improvement.
INTRODUCTION

This appendix discusses components of performance indicators that are not discussed in the case studies.

TOTAL UNSERVED ENERGY

Utilities worldwide have difficulty serving their entire customer load continuously. Total megawatt hours of T&D-related unserved energy is difficult to measure because doing so entails determining how much electricity would have been consumed if the full load had been served. Unserved energy can be estimated, however, by recording the time (duration) that each circuit is off and estimating (on average) the interrupted customer load based on circuit loadings. Totaling the individual unserved energy figures yields an estimate of total unserved energy. This total, divided by total energy generated net of station losses gauges the extent of unserved energy as a percentage of total energy.

When unserved energy is kept low, revenues are kept high because meters are kept turning. More important, customers will be more confident of a stable power supply and will therefore be more willing to connect loads essential to their business. If supply is not stable, loads could well be served from alternative sources such as autogeneration or direct mechanical drives. Such situations may not reflect the best use of resources if power supplies were reliable.

OPERATION AND MAINTENANCE COSTS AS PERCENTAGE OF REVENUES

T&D managers must control total O&M costs, because little can be done to control load growth and its related requirement for T&D capital investments.

O&M costs should be tracked as a percentage of total revenue, rather than in absolute terms, because O&M expenses should increase as load and number of customers increase. Over time, this indicator will reflect changes in the level of O&M.

O&M costs as a percentage of total revenue should not register sudden increases unless required maintenance has been ignored in previous years. O&M resources are best applied at a steady rate which produces a stable relationship between O&M costs and T&D system availability.
APPENDIX IV-B
Page 2 of 2

TOTAL FULL-TIME EQUIVALENT T&D STAFFING YEARS PER MWH GENERATED

The total full-time equivalent number of T&D employees, when divided by total MWh generated to provide a ratio indicator is a good measure of employee effort. The full-time equivalent should be adjusted to reflect overtime and employment of temporary or contract employees.

The full-time equivalent ratio can be tracked over time for internal budget purposes or can be compared with other utilities with similar operating conditions.

While T&D operating requirements should vary only slightly over time, maintenance costs can often be reduced during times of reduced available resources. Maintenance levels should be reduced only temporarily, however, because costs will escalate rapidly as the T&D system deteriorates.

ECONOMIC GENERATION CONSTRAINT

From time to time utilities are unable to use all of their native generation sources as economically as possible because their transmission system capabilities are limited. Transmission constraints can similarly restrict interchange purchases or sales. Such constraints should be documented by recording an estimate of MWh of lost capacity.

Instances of constraint should be monitored over time so that the severity of the problem and relative costs are pinpointed. Frequent instances of sufficient magnitude may necessitate changes, which might include: revising operating procedures to reschedule maintenance, re-examining line-loading constraints under various operating conditions, building new transmission facilities, or reinforcing existing transmission capability.

AGGREGATE INDICATORS

In general, aggregate indicators—such as total staffing years per customer and overall O&M cost per kWh—are not useful for identifying cost effective improvements in a utility. They can be useful, however, for identifying areas that warrant further investigation—much as aggregate statistics analysis (see Chapter II) is used for the same purpose. Such indicators should be compared with year-earlier measurements. The cause of any year-to-year changes if it can be determined, should be carefully documented for future reference.

MAJOR CHANGES IN INDICATORS

If major changes in transmission and distribution indicators are recorded, areas that need further attention can be identified easily. Such changes should be noted on the reporting documents.
Recall that the three steps of this element are:

* Identifying desired performance levels and comparing them with the utility's actual performance level to identify potential cost-effective opportunities for improvement.

* Determining feasibility and cost benefits of achieving the desired performance level.

* Developing an action plan.

Each of these steps will be discussed in the case studies of transmission circuit interruptions and distribution transformer losses.

**TRANSMISSION CIRCUIT INTERRUPTION CASE STUDY**

**Background.** Transmission circuit interruptions are defined here as those circuit outages on the transmission system resulting from an unanticipated or unplanned event. Planned transmission outages, while a significant factor in overall system reliability, are not considered here.

A transmission line may be forced out of service by such events as the operation of protective equipment in clearing a fault; natural or external events, such as earthquake, airplane collision, lightning destruction, or sabotage; or cable failure caused by insulation problems or line fatigue; or failure of other equipment (e.g., transformers and circuit breakers) to operate properly. Forced outages on the transmission system can be most vexing because of their randomness, unpredictability, and potential to spread (or cascade) and interrupt electrical service to the entire system. In addition, single-circuit outages may result in capacity limitations, which prevent the delivery of electricity to certain loads even if the system has adequate generating capacity.

Transmission circuit interruptions—when they stop supply to customers—are reflected by the unserved energy performance indicators (discussed previously), which can be quantified in terms of costs versus lost revenues for the system. From the customer's viewpoint, the target level of reliability may vary significantly depending on how much customers are willing to pay for reliable service. Certain customers may settle for a significantly lower level of reliability than others if costs are correspondingly lower. Since the utility's customers are a collection of diverse groups, the utility must judge the various priorities of each group. 1/

---

1/ Customer surveys are useful in this regard.
The value a customer places on reliable electricity reflects the costs incurred by that customer as a result of a service interruption (i.e., the cost of unserved energy). The cost of an interruption to an industrial or commercial customer can be measured by the value of lost production or sales and the increased costs that may be caused by a power supply interruption. The cost to a residential customer must be measured—to the extent possible—in loss of comfort, convenience, and personal security. Such a loss varies from customer to customer and country to country, and depends in part on the customer's expectations and past experience with service interruptions.

Significant annual savings can result from reducing transmission circuit interruptions. An actual management review identified potential monthly savings of $700,000 by reducing interruptions on the utility's 345 kV transmission line, which linked its largest generation station with its primary external interconnection point. Past interruptions had rendered the line so unreliable that sales to outside utilities declined severely.

A range of approaches can be used to reduce system transmission interruptions; the one chosen will depend on the utility's design philosophy. One philosophy is to achieve a very high system availability by using the highest quality components and many redundant and parallel systems. An alternative philosophy depends more on speed of maintenance and restoration, with less component redundancy. Although this system would fail more frequently, it would also register high availability because service is quickly restored to full operation. Utilities generally choose positions between these two extremes, depending on the specific circumstances involved. The major costs of increased reliability are in the addition of facilities. Since equipment will always fail at some point, greater numbers of backup options provide more reliability. The cost of those backup options determines whether they are provided. A system with poor reliability can generally increase its reliability markedly with a relatively small investment, but a system with high reliability can usually increase reliability only slightly, even with a large investment. Determining the optimal investment in reliability is imprecise but must be done nevertheless and can be rewarding.

This case study assumes that the hypothetical utility's system has relatively poor reliability: registering 5.6 transmission circuit interruptions per 100 km for all voltage levels. This has increased from 3.5 interruptions four years ago. 1/

---

1/ Adequate data collection requires a reasonable level of supervisory control and data acquisition (SCADA) equipment. If SCADA-type information is not available, then line interruption data recorded at the substation site can be used. If the number of interruptions is not recorded, then estimates of them—based upon similar lines—must be substituted. Data should be interpreted with care.
Identifying Desired Performance Levels and Comparing Them to the Utility's Actual Performance Level to Identify Potential Cost-Effective Improvement Opportunities. For this case study, management and efficiency studies do not provide relevant data. The only applicable figure would be the interruption frequency used in the design of the circuit—which would of course be zero under ideal conditions. The three other techniques described in Chapter II do apply. They are:

1/ Intracompany Comparable Work Units—Information on individual circuit interruption performance is valuable. Not all circuit operating conditions are comparable, but under reasonably similar conditions interruption experience can provide a valid comparison. A wide range of interruption incidence per 100 circuit km is not uncommon. For the hypothetical utility, this indicator ranges from less than one annually to more than six annually for individual lines.

2/ Intracompany Performance Analysis Over Time—The utility's four-year increase in transmission circuit trip-outs per 100 km from 3.5 to 5.6 resulted in unserved energy of 10,800 MWh during the past year. This type of comparison is well-illustrated graphically (see Figure IV-C-1). The graphic presentation shows a steady increase in interruptions.

3/ Comparable Performance Indicators Analysis Over Time—Statistics from comparative data sources indicate a transmission interruption per 100 km of 2.9.

From these three performance indicators, several conclusions are apparent: The utility is showing decreased performance. The utility's performance indicator is higher than a comparable average of a large number of utilities, and work-unit information shows that similar lines have widely varying interruption levels. These factors indicate that there is a potential performance improvement in the transmission circuit interruption rate.

---

1/ For both case studies, specific numbers will be assumed to provide the information necessary for understanding the PI/MRS process. In using the PI/MRS process, however, a utility would determine this information.

2/ These figures were not available from the survey study. Industry sources were used instead.
FIGURE IV-C-1

GRAPHICAL PRESENTATION OF TRANSMISSION CIRCUIT INTERRUPTIONS (FOR ALL VOLTAGE LEVELS)
FOR THE LAST SIX YEARS

Interruptions per 100 km

<table>
<thead>
<tr>
<th>Year</th>
<th>Time</th>
</tr>
</thead>
<tbody>
<tr>
<td>One</td>
<td></td>
</tr>
<tr>
<td>Two</td>
<td></td>
</tr>
<tr>
<td>Three</td>
<td></td>
</tr>
<tr>
<td>Four</td>
<td></td>
</tr>
<tr>
<td>Five</td>
<td></td>
</tr>
<tr>
<td>Six</td>
<td></td>
</tr>
</tbody>
</table>

(present)

(Current level of 5.6)
All of the indicators provide valuable information for setting the desired performance level. The 3.5 level registered four years ago indicates that this level is probably achievable simply by increasing maintenance. The 2.9 figure for comparable utilities indicated that the utility could probably achieve this level. This is further supported by the wide fluctuations in interruption levels within the system. Based on all the available information, a desired performance level of 2.8 seems capable of achievement. 1/

Determining Feasibility and Cost Benefits of Achieving the Desired Performance Level and Estimated Cost-Effective Improvements

The hypothetical utility is assumed to have 965 circuit km of transmission line. During the past year, there were 54 transmission circuit interruptions (5.6 per 100 km), which resulted in unserved energy of 10,800 MWh (on average, 200 MW for one hour, 54 times during the year). If this amounted to lost revenues of about $0.10 per kWh, 2/ the total revenues lost to unserved energy during the past year would be 10,800 MWh x 0.10 per kWh, or $1.08 million. If the direct cost of serving this energy is roughly $0.05 per kWh, 3/ the utility has lost net revenue of $540,000 in one year. If the transmission circuit interruption rate of 5.6 were reduced to the desired performance level of 2.8, the desired performance level would result in additional annual net income of approximately $270,000, less applicable improvement costs.

Such an approach is necessary for placing a value to the utility on the level of reliability. The additional value to customers and to the economy of the country, however, is difficult to determine, as was discussed in the background for this case study. The utility must make a judgment on the level of investment that is prudent to improve reliability. Chapter V of this manual discusses a customer satisfaction performance measure, which should be developed to determine specific customer needs. With this information, the utility can evaluate the compromises customers are willing to make between reliability and cost of service.

If the utility concentrates only on the quantitative cost savings from achieving the desired performance level, then specific system improvements must be identified, and the costs of these improvements must be weighed against the potential annual benefits of $270,000. Before identifying specific improvement opportunities, however, additional statistics on the

1/ As noted in Chapter II, desired performance levels are largely based on management judgment and should be used as benchmarks in the PI/MRS process. The utility may well find that is it not cost beneficial to try to attain this level. A detailed investigation may also indicate that a level even better than the original target can be attained.

2/ Incremental value of electricity at the meter. This would be adjusted for the specific utility.

3/ Incremental cost of generation.
transmission circuit interruptions should be gathered so that the utility can fine-tune its efforts. An example of the types of information needed for this purpose is shown in Table IV-C-1.

In considering the range of options for improving the interruption level, the utility's emphasis should be on achieving immediate cost savings and efficiency improvements, then on investigating opportunities for greater cost economies by using advanced technology and incurring additional costs. Experience has shown that increased inspection and maintenance provides the greatest immediate benefits. This option will be discussed first, followed by a discussion of additional equipment.

(1) Inspection and Maintenance. The hypothetical utility is assumed to be experiencing a random pattern of circuit interruptions because of the operation of ground fault and distance relays, which often indicates the need for line repair or maintenance.

A routine inspection program should be considered. It would provide information on where line equipment or vegetation could be causing present problems or will be likely to cause future problems. Each transmission line should be surveyed every 6 to 12 months. Lines that are long and reasonably straight lend themselves to survey using fixed high-wing aircraft with short take-off/landing and low-speed stalling characteristics. Lines that are less amenable to aerial survey, particularly those in urban areas, may be surveyed using a helicopter or foot patrols. Closer inspections should be conducted to spot broken or cracked insulators, missing line and static wire clamps, and slipping or missing feeder number and safety signs.

Trees and other wood vegetation along the transmission right of way should be inspected by foot patrol at suitable intervals depending on their rate of growth. Growth that could interfere with line operation should be scheduled for trimming or removal. Where wood poles are used, measures to inhibit fire risks should be taken.

Each transmission structure and all related equipment should be closely inspected—by climbing the structures—about every five years. Clamps and devices that hold the conductor and earth wire should be tightened or reseated, and guys on wooden structures and bolts on steel towers should be checked for tightness.

Any problems identified during inspection should be noted on formal transmission maintenance work requests, and repairs should be made as soon as possible.
TABLE IV-C-1
TRANSMISSION CIRCUIT INTERRUPTIONS
STATISTICAL INFORMATION

<table>
<thead>
<tr>
<th></th>
<th>138 kV</th>
<th>230 kV</th>
<th>345 kV</th>
<th>TOTAL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of transmission interruptions</td>
<td>31</td>
<td>16</td>
<td>7</td>
<td>54</td>
</tr>
<tr>
<td>Transmission inter-ruptions per 100 CCT-km</td>
<td>7.0</td>
<td>5.8</td>
<td>4.4</td>
<td>5.6</td>
</tr>
<tr>
<td>Number of transmission circuit km</td>
<td>563</td>
<td>241</td>
<td>161</td>
<td>965</td>
</tr>
<tr>
<td>Line-related outages</td>
<td>17</td>
<td>13</td>
<td>4</td>
<td>34</td>
</tr>
<tr>
<td>Line-related outages per 100 km</td>
<td>3.0</td>
<td>5.4</td>
<td>2.5</td>
<td>3.5</td>
</tr>
<tr>
<td>Terminal-related outages</td>
<td>12</td>
<td>3</td>
<td>2</td>
<td>17</td>
</tr>
<tr>
<td>Terminal-related outages per 100 km</td>
<td>2.1</td>
<td>1.2</td>
<td>1.2</td>
<td>1.7</td>
</tr>
<tr>
<td>Interruptions due to unknown causes</td>
<td>2</td>
<td>0</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Interruptions due to unknown causes per 100 km</td>
<td>0.4</td>
<td>0</td>
<td>0.6</td>
<td>0.3</td>
</tr>
</tbody>
</table>
Although inspection and maintenance costs vary by system, the hypothetical utility is assumed to spend approximately $125,000 per year on this function (50 man-months of maintenance time, valued at $2,000 per month, or a total of $100,000 and $25,000 in transport and stores). In return, the utility would reduce interruptions to 3.1 per 100 km in three years, which by itself almost achieves the desired performance level. After one year, a level of 3.7 would be achieved—yielding savings of $166,000 and net benefits of more than $41,000. After two years, the level would be 3.4, producing net benefits of $69,500. After three years, the 3.1 level would provide net benefits of $97,000. These benefits do not include those that result from greater customer satisfaction or general economic improvements. All of these numbers would, of course, be closely scrutinized before the program is adopted.

(2) Additional Equipment. Additional equipment is required when lines or transformers are being overloaded, causing protective relay devices to operate. This tends to occur when load growth is high or equipment is old. When such interruptions are frequent, utilities typically add transmission capability by reconductoring existing lines and continue to operate at the same voltage. Alternatively, converting the line and associated substations to a higher voltage may be feasible.

Before making capital improvements, the utility should identify lines that appear to offer the best returns (Table IV-C-1 can assist in doing this) and should perform a cost-benefit analysis on them. Because the utility's interruptions vary significantly from line to line, additional equipment will probably improve overall results markedly if it is added to the most troublesome lines. Equipment may well reduce system-wide interruptions to the desired 2.8 level or lower.

Developing an Action Plan. An action plan is intended to formalize the specific steps (with targets and milestones) that will achieve the benefits. A formal process establishes a plan that can be used as a guide for implementing the action and monitoring its progress. Sub-action plans, based on this action plan, should be developed for use below the manager level to ensure that subordinates are fully aware of all steps required to implement the plan.

The action plan includes the following phases:

- Phase I - Elaborate in detail the initial cost-benefit analysis.
- Phase II - Define the work to be done and do the work in priority order.
- Phase III - Evaluate other opportunities for improvement and select the next most-promising improvement opportunity.
The first two phases of this action plan are described in detail below.

**Phase I.** Review initial feasibility and cost-benefit analysis indicating that inspection and maintenance improvements are the highest-priority actions.

(1) **Time Frame.** Three months.

(2) **Objective.** A final action plan, listing proposed costs and benefits, to be formulated by the end of three months.

(3) **Costs.** Three man-months of data analysis ($6,000) and one man-month of engineering analyst time ($5,000), for a total of $11,000. 1/

(4) **Benefits.** Confirmation of the highest-priority improvement opportunity and development of a final action plan.

**Phase II.**

* **Step 1**—Identify specific, cost-beneficial inspection and maintenance initiatives to reduce number of circuit trip-outs.

(1) **Time Frame.** One month to identify initiatives.

(2) **Objective.** Develop specific implementation plan, including costs and benefits.

(3) **Costs.** To identify initiatives—one month of engineering analyst time, or $5,000.

(4) **Benefits.** A list of actions that can be implemented in step two.

* **Step 2**—Implement inspection and maintenance improvement opportunities.

---

1/ Engineering analyst time is assumed to cost $5,000 a month. Data analysis time is assumed to cost $2,000 a month. Note, these and all other costs are based on fully loaded (wages plus benefits) compensation of typical U.S. utility employees.
(1) **Time Frame.** An ongoing effort that should be started as soon as possible.

(2) **Objectives.** Reduction of circuit trip-outs to 3.7 after one year, 3.4 after two years, and 3.1 after three years.

(3) **Costs.** $125,000 annually.

(4) **Benefits.** $41,000 (net) in first year, $69,500 in second year, and $97,000 in succeeding years.

A Summary Action Plan that can be used for upper management review is presented in Table IV-C-2.
TABLE IV-C-2
SUMMARY OF TRANSMISSION CIRCUIT
INTERRUPTION ACTION PLAN

Overview of Action Plan

Develop formal program to reduce transmission circuit trip-outs by in-depth analysis of outage causes and characteristics and by comparisons with intracompany trends and composite industry statistics.

Implementation Steps

Phase I - Elaborate in detail the initial cost-benefit analysis.

Phase II - Define the work to be done and do the work in priority order.

Phase III - Evaluate other opportunities for improvement and select next most promising improvement opportunity.

Study time for Phase I is three months. Full implementation time for Phase II is three years, but some benefits would be realized immediately. For Phase III, elapsed time depends on specific initiatives adopted.

Cost of Action Plan

$11,000 for Phase I analysis time. For Phase II, initial cost is $5,000 and annual cost is $125,000. Phase II implementation costs depend on specific initiatives undertaken.

Net Benefits of Action Plan

In the first year, net benefits would be $25,000 ($41,000 - $16,000). In the second and third years, net benefits would be $69,500 and $97,000, respectively. Benefits are greater if customer satisfaction and economic benefits are included.
This case study evaluates the economic effects of distribution transformer losses for early retirement considerations. 1/

Background. Utilities are devoting increased attention to calculating and evaluating losses on electric utility systems because operating and fuel costs are increasing, higher efficiency is increasingly important, design technologies are offering new advances. Experience shows that older transformers generally incur higher losses. Increased operating costs (based upon the incremental value of lost kWh) require utilities to consider the evaluation of potential losses when deciding whether to purchase a transformer. Transformers with newer designs generally incur lower losses, which results in reduced operating costs. Studies should therefore be performed to determine the cost-effectiveness of replacing older transformers with newer, lower-loss transformers. When transformer replacements are evaluated, the cost of losses should be based on the system incremental cost of producing energy rather than on the average cost of energy. This is appropriate because the energy generated to supply the losses in the older transformer is system incremental energy above what would be needed with newer, low-loss transformers.

Because distribution transformers represent some 80% of all installed electric system transformers, cumulative losses are significant. 2/ Older distribution transformers (over 25 years old) were designed when the incremental cost of a kW of capacity and the associated lifetime energy loss led to lower valuations. It was therefore not as important commercially that these older designs be as efficient as those now being designed.

Efficiency is, however, only one consideration in deciding which distribution transformers to purchase. Other factors are reliability, installation cost, and unit purchase price. Nonetheless when deciding to replace in-service distribution transformers with new transformers, efficiency is of primary importance.

A recent management review for an electric utility indicated that 20% of the utility's 10,000 distribution transformers were more than 25 years old. Not all of these transformers had been located at the same site for 25

---

1/ In addition to transformer losses, line losses (and the value of reconductoring) could be separately considered as opportunities for improvement.

2/ This case study assumes that the distribution transformers are of a standard, single-phase 25 kVA size.
years, but all were still in service. The review concluded that 225 watts 1/ per transformer could be saved if newer, more efficient transformers replaced transformers more than 25 years old. This translates to an annual saving per transformer of 1,971 kWh. Each kWh had an incremental cost of $0.05 (at the meter), so that annual revenue of about $98.5 per transformer could be saved by replacement. The cost of purchasing and installing a new transformer was $500, so replacement had a payback of about five years assuming no residual value for the old transformer.

The hypothetical utility will be assumed to have 5,000 distribution transformers at 25 kVA with 1,000 of these over 25 years old.

Identifying Desired Performance Levels and Comparing Them to the Utility's Actual Performance Level to Identify Potential Cost-Effective Improvement Opportunities. The primary performance indicator for this analysis is evaluation of the design loss factor of the new distribution transformers (an industrial engineering indicator). Distribution transformers operate at their design loss level. So the key to identifying cost savings in this analysis is to evaluate the hypothetical utility's age distribution (and corresponding losses) for its in-service distribution transformers and determine if installing new distribution transformers is cost beneficial.

Industry statistics compiled by major manufacturers indicate that new distribution transformers have losses in the 300 to 325 watt range, while 25 years-old transformers have average losses of 500 to 525 watts. By sampling its transformers that are 25 or more years of age, the hypothetical utility has confirmed this figure. Based on the industry data, a desired performance level of 300 to 325 watts for new transformers seems appropriate. Although further studies of newer transformers (less than 25 years old) would probably also show significant watt savings with replacement, the utility decides to start by replacing only the oldest transformers to get the best return on investment.

Determining Feasibility and Cost Benefits of Achieving the Desired Performance Level and Estimated Cost Effective Improvements. Setting a desired performance level of 300 to 325 watts for new distribution trans-

---

1/ The 225 watt loss is based on the mean transformer loading over time (which is based on estimated no-load losses of 80 watts and full-load losses of 620 watts for a single phase 25 kVA distribution transformer.)
formers establishes a potential improvement opportunity of 200 watts annually. Assuming the incremental value of additional generation is $0.05 per kWh, the utility is setting a target of $88 annual savings per transformer (200 watts x 8,760 hours x $0.05 per kWh). Assuming the cost of a distribution transformer, including installation, is $500, the utility should see its investment paid back in about six years. 1/

Developing the Action Plan. The action plan consists of three phases:

- Elaborate initial estimates of cost savings and highest-priority improvement opportunities.
- Develop and implement program for highest-priority improvements.
- Evaluate other improvement opportunities.

The first two phases are discussed in detail below.

Phase I. Elaborate initial estimates of cost savings and highest-priority improvement opportunities.

(1) Time Frame. Three months.

(2) Objective. A final action plan, including proposed costs and benefits, to be formulated by the end of three months.

(3) Costs. Two man-months of test measurements and analysis ($6,000) and two man-months of engineering analysis ($10,000), for a total of $16,000.

(4) Benefits. Confirmation of cost savings and highest priority improvement opportunities.

1/ In practice, the utility would perform a detailed cost-benefit analysis that considers all factors, such as phasing in and out of benefits and costs, transportation costs, import taxes, capital budgeting considerations, and net present value. Although this manual does not discuss these techniques, the utility analyst should be fully knowledgeable in conducting detailed cost-benefit analyses.
Phase II.

- **Step 1**--Develop formal program for implementing highest-priority distribution transformer replacements; that is, the 1,000 transformers that are 25 years of age and older.

1. **Time Frame.** Three months.
2. **Objective.** Produce formal transformer replacement report documenting implementation steps, costs, and savings.
3. **Costs.** Three man-months of engineering analysis time, or $15,000.
4. **Benefits.** Identification of best candidates for improvement.

- **Step 2**--Implement the program for the oldest 1,000 transformers.

1. **Time Frame.** One year.
2. **Objective.** Replace all 1,000 transformers.
3. **Costs.** $500 per transformer.
4. **Benefits.** The transformers are assumed to be installed. This can be expressed as a one-time capital cost of $500,000 halfway through the year. The benefits per transformer are only one-half of $88 (since they are installed evenly throughout the year) for a total benefit of $43,250. In year two and thereafter, the benefits will be $86,500. In about six years after the initial capital cost, the transformers will be paid back.

A summary action plan is presented in Table IV-C-3.
TABLE IV-C-3
SUMMARY OF DISTRIBUTION TRANSFORMER LOSS ANALYSIS
ACTION PLAN

Overview of Action Plan

Develop and implement formal program for replacement of distribution transformers.

Implementation Steps

Phase I - Elaborate initial estimates of cost savings and highest-priority improvement opportunities.

Phase II - Develop and implement program for highest-priority transformers.

* Step 1 -- Develop formal program for most cost-effective replacement of distribution transformers.

* Step 2 -- Implement the program for the 1,000 transformers that are 25 years old and over.

Phase III - Evaluate other improvement opportunities.

Phase I should be completed in three months. The first step in Phase II should be completed in three months. Step two of Phase II should be completed in one year.

Cost of Action Plan

| Phase I - | $ 16,000 |
| Phase II, Step 1 - | $ 15,000 |
| Phase II, Step 2 - | $500,000 |
| Phase III - | Unable to determine. |

Net Benefits

Six-year payback: net costs avoided thereafter of $86,500 annually.
SURVEY RESULTS COMPILING COMPARATIVE TRANSMISSION AND DISTRIBUTION PERFORMANCE INDICATORS FROM SELECTED UTILITIES AROUND THE WORLD

DEFINITIONS OF GRAPHS/TABLES

To ensure proper interpretation of these values, they are defined as follows:

* Minimum Value - The lowest data point on the frequency distribution.
* Maximum Value - The highest data point on the frequency distribution.
* Mean Value ($\bar{x}$) - The average—computed as the summation of data observations divided by the total number of observations.
* Standard Deviation (Sd) - A measure of the data variation around the mean value computed as:

$$S_d = \sqrt{\text{Var } x}$$

Where $\text{Var } x = \frac{\sum (x_1 - \bar{x})^2}{n}$

1. Percentage of Internal Plant (Metered and Unmetered) Losses

A. Percentage of Gross Generating Losses

Gross Generation - Net Generation

$\times$ Gross Generation

(Internal plant electrical losses)

* Net generation is energy sent out to transmission/distribution system.

1/ See Chapter II for a discussion of survey methodology.
B. Percentage of T&D Losses

\[
\text{B. Percentage of T&D Losses } 1/ = \frac{\text{Net Generation} - \text{Energy Sold} 2/}{\text{Net Generation}}
\]

INDICATORS

The following figures are attached.

* Figure IV-D-1: U.S. Generic Performance Indicator (Total System Losses) 3/
* Figure IV-D-2: International Generic Performance Indicator (Total System Losses) 3/

---

1/ If facilities for metering the transfer between transmission and distribution exist, provide separately.

2/ Energy Sold should include any used and metered at zero price, such as in staff housing, the utility's offices, control centers or other similar installations.

3/ These losses include both internal plant losses and transmission and distribution losses. The results of the survey could not differentiate the losses. Note, these figures also include energy theft losses which are only discussed in Chapter V.
FIGURE IVD-1

U. S. Generic Performance Indicator

INDICATOR: Total System Losses

<table>
<thead>
<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>2.1%</td>
<td>15.00%</td>
<td>7.01%</td>
<td>3.16%</td>
</tr>
</tbody>
</table>

SYSTEM LOSSES

<table>
<thead>
<tr>
<th>PERCENT</th>
<th>SYSTEM LOSSES</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-2%</td>
<td></td>
</tr>
<tr>
<td>2%-3%</td>
<td></td>
</tr>
<tr>
<td>3%-4.5%</td>
<td></td>
</tr>
<tr>
<td>4.5%-6%</td>
<td></td>
</tr>
<tr>
<td>6.1%-7.5%</td>
<td></td>
</tr>
<tr>
<td>7.6%-9.5%</td>
<td></td>
</tr>
<tr>
<td>9.6%-10%</td>
<td></td>
</tr>
<tr>
<td>10%-12%</td>
<td></td>
</tr>
<tr>
<td>12%+</td>
<td></td>
</tr>
</tbody>
</table>

SYSTEM LOSSES DATA DISTRIBUTION

MEAN = 7.01%
FIGURE IVD-2

International
Generic Performance Indicator

INDICATOR: Total System Losses

<table>
<thead>
<tr>
<th>Minimum Value</th>
<th>Maximum Value</th>
<th>Mean Value</th>
<th>Standard Deviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.2%</td>
<td>8.4%</td>
<td>5.96% 1/</td>
<td>1.82%</td>
</tr>
</tbody>
</table>

1/ The low mean value is due to the limited data base of only several urban utilities. Total losses for utilities serving large areas requiring extensive transmission are typically much higher.
CHAPTER V
APPLICATION OF PI/MRS PROCESS TO
COMMERCIAL OPERATIONS

INTRODUCTION
This chapter discusses how the PI/MRS process is applied to the commercial operations of the utility and provides examples--using a hypothetical utility--to illustrate this application. 1/

Commercial operations encompass all activities that complement generation, transmission, and distribution. In this manual, commercial operations include customer services, accounting, supply management (including materials and fleet management), and human resources support. 2/ It is assumed that each of these areas is headed by a manager in the hypothetical utility and that these managers report to the commercial general manager. The commercial general manager reports to the chief executive, who is the utility's chief executive officer.

This chapter is particularly important because, as utility costs have risen, commercial operations have become far more critical in efforts to achieve cost effective improvements. Traditionally, commercial operations and their associated costs have not been tightly controlled because they were perceived to be of a relatively low cost when compared to other major utility functions. The recent rapid increase of commercial costs, however, has emphasized the importance of conducting commercial operations using sound business practices rather than providing "service at any cost." Commercial costs typically account for 25% to 35% of a utility's non-fuel operating budget, or 12.5% to 17.5% of the utility's overall operating budget. 3/

Performance indicators can measure to what extent the objectives of commercial operations have been achieved. This manual assumes that the overall objective of commercial operations is to "perform commercial functions in a way that enables the utility to provide safe, reliable service at minimum cost." On an operating level, the following objectives must be attained by the commercial function for this overall objective to be achieved:

---

1/ Although this chapter can stand alone, commercial personnel may want to read the other two applications chapters (III and IV) to understand better how the PI/MRS process is applied to the other major functions of a utility.

2/ Human resource management must remain in the hands of those who manage the utility's operations. Therefore, this area is assumed to include only personnel support functions.

3/ Table II-1 (Volume I, page 14) illustrates these figures.
- 181 -

- Provide satisfactory service to customers.
- Perform all commercial functions in the most cost-effective manner.
- Provide adequate support service for planning, operating, and construction.
- Support company personnel to realize maximum productivity of human resources.

The remainder of the chapter is divided into six sections that correspond to the six elements of the PI/MRS process described in Chapter II:

- Identifying useful staffing and operational performance indicators.
- Developing the performance indicator data base and reporting requirements.
- Identifying possible cost-effective improvement areas and developing action plans to achieve them.
- Developing reporting documents to (1) monitor the cost effective improvement plans and (2) provide management with information essential for managing the utility's operations.
- Integrating the PI/MRS process with planning and budgeting cycle to provide incentive for full achievement of cost effective improvements.
- Integrating the PI/MRS process into the human resource aspects of the utility.

IDENTIFYING USEFUL STAFFING AND OPERATIONAL PERFORMANCE INDICATORS FOR COMMERCIAL OPERATIONS

Manager Level Performance Indicators. Annex V-1 presents a menu of indicators for each of the commercial operations, designed for use at the manager level. Exhibits V-1 through V-5 provide the following information for each of these indicators:

- How the performance indicator assists in measuring the achievement of objectives.
- Why each indicator is an important measuring level of customer service, level of support to other parts of the utility, or overall cost. (This includes a discussion of what the performance indicator measures, how the performance measures are calculated, and the level to which the performance indicator should be addressed.)
Appendix V-A provides additional information about important aspects of the exhibits.

To ensure that the utility's overall objectives are achieved, performance indicators should be identified for all levels of the utility below the manager level.

**Commercial General Manager Performance Indicators.** To measure the overall effectiveness of commercial operations, the commercial general manager needs a comprehensive set of performance indicators that measures each of the four commercial activity objectives discussed previously. Annex V-2 lists the most important indicators for each of the four objectives.

**Chief executive Performance Indicators.** The chief executive is primarily concerned with commercial operations that have a major impact on the utility, so his major objective is to guide the utility in these areas. This objective is addressed by the performance indicators listed in Annex V-3. Because these indicators are important they have been termed critical performance indicators.

**DEVELOPING THE PERFORMANCE INDICATOR DATA BASE AND REPORTING REQUIREMENTS**

The generic discussion in Chapter II is applied to the commercial function in Exhibits V-1 through V-5—which detail the type of data needed to compute the commercial performance indicators.

**IDENTIFYING POSSIBLE COST-EFFECTIVE IMPROVEMENTS AND DEVELOPING ACTION PLANS TO ACHIEVE THEM**

The case studies presented in Appendix V-C illustrate how this element is applied to the commercial function. 1/ Two critical performance indicators—billing lag and energy theft by case study example in Appendix V-C, 2/—have been chosen to show how the three steps involved in this element would be performed.

The case studies assume various figures and conditions for the hypothetical utility to demonstrate more effectively how the PI/MRS process can be used to identify and achieve cost economies. The assumptions (as well as the analysis of the figures in the PI/MRS process) are based on experience with several power utilities.

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1/ The case studies are intended only to demonstrate the PI/MRS process—they do not present the detailed, comprehensive analysis that would be part of a utility's actual PI/MRS activities.

2/ Appendix V-B provides additional information (but not case studies) to assist in applying the PI/MRS process to the other critical commercial performance indicators.
In order to permit the method of analysis that uses comparative figures from other utilities, Appendix V-D presents the results of Ernst & Whinney's survey of international utilities. This survey identified the following commercial performance indicators: non-generation employees per 1,000 customers, inventory as percent of net assets, billing lag, average collection period, and percent uncollectable revenues. To reflect the actual operating experience of utilities in the comparative figures used in the case studies, figures obtained from the survey are used. As noted in Chapter II, however, comparative performance indicators must be used with care; so the Chapter II discussion of comparative indicators should be read carefully before proceeding with the case study examples.

DEVELOPING REPORTING DOCUMENTS TO (1) MONITOR THE COST-EFFECTIVE EFFICIENCY-IMPROVEMENT PLANS AND (2) PROVIDE MANAGEMENT WITH INFORMATION ESSENTIAL FOR MANAGING UTILITY OPERATIONS

To show how this element is applied to commercial operations, the consumer billing lag case study will be used as an example. The case study is presented by month to show how reporting documents are developed.

Month One, Year One. At this time, the hypothetical utility is preparing annual plans and budgets. No desired performance level has been established for the large consumer billing lag. The current lag is eight days. 1/ Assumed time constraints lead the hypothetical utility to apply an abbreviated version of the PI/MRS and to develop an initial action plan with the following targets: 2/

* Reduce billing lag from eight days to six days in two months (final target).
* Reduce billing lag to seven days after one month (interim target).
* Realize annual net benefits of $100,000, with initial costs of $8,000.

This information is incorporated into the annual budget (estimated savings of $100,000 for the upcoming year).

1/ In the billing lag case study used to illustrate the action plan, the initial lag was assumed to be six days. An initial lag of eight days is assumed here to show how savings can be achieved by developing an initial action plan during the planning and budgeting process, with additional savings possible when a formal action plan is adopted later.

2/ Appropriate steps to achieve the target are assumed to be developed.
Month Two, Year One. The Performance Indicator Reporting Document for the consumer billing lag—month two, year one—is presented in Exhibit V-6, which shows the following:

* **Current Reporting Information** — The current lag is eight days (the company made no improvement during the test month). The current target is seven days, with an established acceptable deviation of 1/4 day. Because the actual deviation exceeds the acceptable deviation by 3/4 day (1-1/4), an exception report is triggered. The loss in net benefits caused by missing the target by one day, based on the initial action plan, is $6,000 (that is, one-day loss for 1/12 of a year).

* **Year-End Reporting Information** — The originally planned target for month 3 is six days with an acceptable deviation of 1/4 day (which is also the desired performance level). Although the month 2 target was not achieved, the utility's analysts believe that the action plan can be changed so that the company will meet its target. No exception report is triggered. Nonetheless, gains fell short by $6,000 during month 2.

This information should be included in a report that incorporates information from all performance indicators for which managers reporting to the commercial general manager are responsible.

Remaining Months of Year One. The hypothetical utility is assumed to have achieved its target of six days during month 3, with that level maintained throughout the year. This result triggers no additional action related to the indicator. Toward the end of year one, utility personnel have time to perform a detailed analysis and develop the action plan (described in the case study) that is considered during the planning and budget process (in Month 12, Year One) for the next year. Thus, Month Two, Year Two would be the first month producing new, current data for the Action Plan Reporting Document (as well as the new Performance Indicator Reporting Document).

Month Two, Year Two. The Action Plan Reporting Document for this period, presented in Exhibit V-7, shows the following:

* **Initial Estimate and Possible Deviations** — This information is taken directly from the billing lag case study action plan.

* **Update of Current Status** — The original plan for month two set a target of four days, with a 1/4-day acceptable deviation. The actual figure is five days—a deviation of one day. This results in a $20,000 difference between the planned benefits ($40,000) and the actual benefits ($20,000), which triggers an exception report.

* **Revised Long-Term Estimate** — The original planned target for month three is 2.1 days with an acceptable deviation of 1/4 day. Although the target for the month was not achieved, the utility’s analysts believe that the action plan can be revised
so that the company can achieve its target by month three. Nonetheless, an annual loss of $20,000 is recorded for month two. A revised action plan is necessary, but no exception report is required because the only expected deviation was described in the current status exception report.

This action plan would be noted on the reporting document every month until the performance level target is achieved or the action plan is revised. Any other action plans, listed in descending order by the amount of expected net benefits, would also be noted on this document. Data would still be included on the monthly Performance Indicator Reporting Document, reporting the formalized action plan, targets, and estimated benefits (and the utility's progress toward these objectives).

INTEGRATING THE PI/MRS PROCESS WITH THE PLANNING AND BUDGETING CYCLE TO PROVIDE INCENTIVE FOR FULL ACHIEVEMENT OF COST-EFFECTIVE IMPROVEMENTS

The generic discussion in Chapter II and the case study of reporting documents provide the necessary information to apply this element to commercial operations. Important aspects of this element are:

- The PI/MRS process can make the planning and budgeting cycle a useful exercise for promoting cost-effective improvements.
- All performance indicators should be reviewed in the planning and budgeting cycle.
- Annual cost revisions noted on the performance indicator reporting document should be used in preparing the annual budget.
- Continuing reviews should be undertaken to focus on future cost savings.

INTEGRATING THE PI/MRS PROCESS INTO THE HUMAN RESOURCE ASPECTS OF THE UTILITY

The following text repeats what was said in Volume II on the subject so that this volume is self-contained.

Employees throughout the utility will be responsible for implementing the action plans derived from the PI/MRS process. These employees must therefore receive information and be consulted in its interpretation. This is especially true for non-management personnel.

The human resource aspects of the PI/MRS process are:

- Employee understanding of PI/MRS process
- A participatory management approach
- 186 -

- Performance evaluation
- Rewards
- Clear communication from upper management
- Training designed to support the action plans

Employee Understanding of PI/MRS Process. Any management process, whether new or existing, must be understood by those involved in its execution and must be perceived to be a benefit to them. If employees are represented by organized labor, union officers must be fully educated in the PI/MRS process. Employees will make an effort to ensure maximum benefits of the process only when they fully understand it. Furthermore, PI/MRS objectives must be described clearly so that both upper and lower management are familiar with its objectives. One way to encourage understanding of the system is to conduct training courses (open to management and non-management employees) in the use of the process.

Participatory Management Approach. The PI/MRS is structured as a top down management approach, under which senior management (1) sets corporate and operating objectives and (2) works with middle management to identify performance indicators that measure these objectives. The identification of cost-effective improvements, as well as identification of performance indicator targets, however, often works most effectively when the process starts at lower management or non-management levels and works its way up (within certain limitations) in a bottom-up approach. This more effectively motivates employees to do a good job, because they initiate and own the process. For example, lower-level employees identify improvements and set targets. They then pass these to the next higher level of supervision or management for approval or revision. Experience shows that the improvement targets prompted by employees in a participatory process will often be higher and better defined (and more achievable) than when supervisors and upper management dictate the targets. This manual does not attempt to repeat the exhaustive and documented research on the benefits of a participatory management approach, but simply points out the potential advantages of the approach in achieving full benefits of the PI/MRS process.

Performance Evaluation. Performance evaluations are used to reinforce proper use of the PI/MRS process. Management and non-management performance evaluations are linked to achieving performance targets over which the individual has control. The links must be established carefully and precisely, so that employees do not feel that their performance evaluation is based only on figures accumulated. If done correctly, such links help keep personal biases from entering into the evaluation process. Performance evaluations linked to appropriate performance indicators and targets will help employees understand that achieving targets will result in more favorable evaluations, encouraging work that promotes the overall objectives of the utility.
Rewards. It is important for employees to receive recognition when they have achieved personal objectives measured in the performance evaluations. The form of the recognition must be based on the utility's particular social culture and business environment and depend on the nature and magnitude of the utility's benefit from employee performance.

Clear Communication from Upper Management. Upper management must ensure that all employees fully understand the importance of cost economy by clearly and consistently reminding employees of the value of cost economy. Further, upper management must communicate overall objectives to employees and point out that these objectives are fostered through the PI/MRS process.

Training Designed to Support the Action Plans. Initial employee training in the PI/MRS process should be followed by periodic reviews to (reinforce initial training). Based on these reviews, supplementary training should be given as necessary.
### MENU OF COMMERCIAL PERFORMANCE INDICATORS FOR USE AT MANAGER LEVEL

<table>
<thead>
<tr>
<th>Commercial areas</th>
<th>Objectives</th>
<th>No indicators identified</th>
<th>No indicators identified</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Customer service</strong></td>
<td>Provide customer with satisfactory service</td>
<td>Maximize efficiency and effectiveness of commercial operations</td>
<td>Provide service support to other functions of utility</td>
</tr>
<tr>
<td>2. Number of complaints per 1,000 customers</td>
<td>7. Staffing years/kWh</td>
<td></td>
<td></td>
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<tr>
<td>3. Weighted average length of wait for service hook-up</td>
<td>8. O&amp;M cost/customer</td>
<td></td>
<td></td>
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<tr>
<td>4. Percentage of service territory electrified</td>
<td>9. O&amp;M cost/kWh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5. Time to make service call</td>
<td>10. Management and efficiency studies of repetitive functions</td>
<td></td>
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</tr>
<tr>
<td>11. Billing lag</td>
<td>12. Time to read 100 meters</td>
<td></td>
<td></td>
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<tr>
<td>13. Percent of meter rereading</td>
<td>14. Meter reading costs/meter</td>
<td></td>
<td></td>
</tr>
<tr>
<td>15. Energy theft (theft only, not distribution efficiency)</td>
<td></td>
<td></td>
<td>(See EXHIBIT V-1.)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Accounting</th>
<th>No indicators identified</th>
<th>1. Accounts receivable lag</th>
<th>9. Frequency of closing of financial books</th>
<th>No indicators identified</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. Bad debt/total revenues</td>
<td>3. Percentage of accounts over three months old</td>
<td>10. Time lag from the end of the period to the producing of the reports</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4. Percentage of security deposits 1/</td>
<td>5. FTE staffing years/customer 1/</td>
<td>11. Budget variances</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6. FTE staffing years/kWh</td>
<td>7. O&amp;M costs/customer</td>
<td>12. Overall utility revenues/expenses</td>
<td></td>
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<tr>
<td>8. O&amp;M costs/kWh</td>
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<td>(See EXHIBIT V-2.)</td>
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</tbody>
</table>

1/ FTE = Full Time Equivalent Employees, which should be categorized—if possible—as management, skilled workers, unskilled workers, support staff.
## MENU OF COMMERCIAL PERFORMANCE INDICATORS FOR USE AT MANAGER LEVEL

<table>
<thead>
<tr>
<th>Commercial areas</th>
<th>Provide customer with satisfactory service</th>
<th>Maximize efficiency and effectiveness of commercial operations</th>
<th>Provide service support to other functions of utility</th>
<th>Provide support to maximize human resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Supply Management</td>
<td>No indicators identified</td>
<td>1. Inventory turnover</td>
<td>14. Stock-out frequency</td>
<td>No indicators identified</td>
</tr>
<tr>
<td>(Materials Management</td>
<td></td>
<td>2. Inventory levels per net revalued assets</td>
<td>15. Cause of stock-outs</td>
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<tr>
<td>Related)</td>
<td></td>
<td>3. Percentage of slow-moving inventory (not used in last 12 months)</td>
<td>16. Percentage of stock-outs causing loss of power or stoppage of major projects</td>
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<td></td>
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<td>4. Inventory variances</td>
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<td>5. Percentage of inventory theft</td>
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<td>6. Percentage of inventory scrapped</td>
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<td>7. Average time from placing of order to receipt of material</td>
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<td>8. Percentage of purchase decisions based on requirements planning</td>
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<td></td>
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<td>9. Percentage of inventory items not used as planned</td>
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<td>10. FTE staffing years/customer</td>
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<td>11. FTE staffing years/kWh</td>
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<td>12. O&amp;M costs/customer</td>
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<td>13. O&amp;M Costs/kWh</td>
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</tbody>
</table>
## MENU OF COMMERCIAL PERFORMANCE INDICATORS FOR USE AT MANAGER LEVEL

<table>
<thead>
<tr>
<th>Commercial areas</th>
<th>Objectives</th>
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<tbody>
<tr>
<td></td>
<td>Provide customer with satisfactory service</td>
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<tr>
<td>Supply Management (Transportation Related)</td>
<td>No indicators identified</td>
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(See EXHIBIT V-4.)

<table>
<thead>
<tr>
<th>Human Resources Support</th>
<th>Objectives</th>
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<tbody>
<tr>
<td></td>
<td>Provide customer with satisfactory service</td>
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<td>No indicators identified</td>
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(See EXHIBIT V-5.)

1/ FTE = Full Time Equivalent Employees, which should be categorized—if possible—as management, skilled workers, unskilled workers, support staff
COMMERCIAL GENERAL MANAGER
PERFORMANCE INDICATORS

Objective: Provide satisfactory customer service

1. Overall customer satisfaction index based customer surveys.
2. Number of complaints per 1000 customers.

Objective: Maximize efficiency and effectiveness of commercial operations

1. Overall commercial staffing years per customer, per kWh.
2. Overall commercial O&M cost per customer, per kWh.
4. Energy theft.
5. Accounts receivable lag.
6. \( \frac{\text{Bad debt}}{\text{total revenues}} \)
7. Percentage of accounts more than three months old.
8. Inventory turnover.
9. Inventory value per net revalued assets.
10. Percentage of slow-moving inventory.
11. Total vehicles and net value per customer, per kWh.
12. Operating costs per vehicle.
13. Average operating cost per housing occupant.

14. Overall utility revenues / \[ \text{expenses} \]

Objective: Provide service support to other functions of the utility

1. Budget variances.

2. Number and percentage of stock-outs causing loss of power or stoppage of major projects.

3. Percentage of training hours per total labor hours; percentage of full-time employees exposed to training for one week or more.

Objective: Provide service support to maximize human resources

1. Employee turnover.

2. Skilled vacancies unfilled.

Objective: Management control of all commercial operations

1. Listing of all major changes and variances in any of the performance measures monitored by commercial managers. 2/

---

1/ Although financial indicators are not discussed in this chapter, the commercial general manager would monitor overall indicators of the financial health of the utility to ensure that operating decisions are financially sound. Overall utility revenues/expenses is one of these indicators.

2/ Including measurement against certain targets, discussed later in this chapter.
Objective: Ensure that the utility is achieving its overall objectives by providing guidance in those commercial areas having major impact on the utility

Performance Indicators

1. Billing lag.
2. Energy theft.
3. Accounts receivable lag.
4. \[ \text{Bad debt} \over \text{total revenues} \]
5. Inventory turnover.
6. Aggregate indicators for entire utility that include the commercial function. 1/

Objective: Overall management control of utility

1. Listing of all major changes and variances in any of the commercial general manager performance measures. 2/

---

1/ The executive general manager will also receive aggregate information on staffing years per customer, overall O&M cost per kWh, and other indicators.

2/ Including measurement against certain targets, discussed later in this chapter.
CUSTOMER SERVICE PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide satisfactory customer service 1/

Performance Indicator

V.1.1. Customer satisfaction index based on surveys

This provides a good measure of the utility customer's opinion of the service provided and whether the cost of electricity is considered a good value. Information from a survey is useful in (1) identifying needs of the customer so that service can be provided cost effectively, (2) identifying potential customer service problem areas and (3) providing planning information for customer service activities. The data source is market research surveys.

V.1.2. Number of complaints per 1000 customers

Because only certain unhappy customers complain, this measure may provide a distorted impression of the service level. This indicator is useful, however, when used as an additional tool or when a survey is not possible. The data source is customer information and accounting records.

V.1.3. Weighted average length of wait for service hook-up 2/

The wait for a hook-up provides a measure of how quickly the utility can respond to new service requests, and it can provide useful information on whether more resources need to be devoted to this function. The data source is customer information and accounting records.

V.1.4. Percentage of service territory electrified

This is a good measure of the utility's overall service in absolute terms. It is not a measure of how good the service is, only how many customers have electricity. The data source is customer information and accounting records as well as general demographic information on all customers in the service territory.

V.1.5. Time required to make service call

Once electricity is provided to a customer, maintenance response must be lowered to provide more reliable service. This indicator measures the utility's capability to respond to service needs. The data source is individual servicemen work orders. Summing up the individual times and dividing by the total service calls will compute this figure.

1/ The customer service discussion does not address indicators such as customer interruptions or load loss. These types of indicators are discussed in Chapter IV.

2/ Hook-up means making supply connection so that customer can start using it.
Objective: Maximize efficiency and effectiveness of customer service activities

V.1.6/7. **Staffing years/customer and staffing years/kWh** 1/

This indicator measures the growth of staffing levels normalized by customers and kWh, the primary driving components of customer service activities. These indicators are useful for identifying employee levels that may not be justified. The data source for staffing years is paymaster's records.

V.1.8/9. **Overall customer service O&M costs/customers and overall customer service O&M Costs/kWh**

These measures, when adjusted to exclude inflation provide information on the overall cost efficiency of the customer service function. The data source for the O&M costs is annual budgetary reports.

V.1.10. **Management and efficiency studies of repetitive functions**

Because the customer function is labor intensive, management and efficiency studies of repetitive customer service functions (such as meter reading, field service activities, billing, and customer service interface) can be useful in providing a measure of employee efficiency versus some "standard" time. These studies are useful for identifying unproductive actions such as standby (caused by poor work scheduling) and for providing some standards of employee efficiency. The studies can also be used to identify training needs. The data source for these studies is the records of the specific departments assigned to perform these special projects.

V.1.11. **Billing lag**

This indicator measures the efficiency of the meter reading and billing process by indicating the elapsed time from reading a meter to sending a bill. Each additional elapsed day requires the utility to use more working capital (and hence pay higher interest charges) to support the delay in getting paid. For a utility with $500 million in annual revenues and a 15% short-term borrowing cost, the cost of each additional day of billing lag is $205,000 annually ($500 million/365 x 15% interest). Because the cost of the lag is proportional to the size of the customer's bill, this indicator should be segmented by class of customer. The data source is customer accounting records.

1/ If possible, staffing years should be based on Full-Time Equivalent Employees. Analysis is more precise if employees are categorized as (1) management, (2) skilled (engineers and non-engineers), (3) technicians, (4) administrative and support, and (5) unskilled.
V.1.12/13/14. Time to read 100 meters, percent of meter re-reads, and meter reading costs per meter

These three measures provide information on the efficiency and cost effectiveness of the meter reading function. The data sources for these measures are meter reader daily productivity sheets (time to read 100 meters), special meter reading work orders (percent of meter re-reads) and annual budgets (meter reading costs). Meter reading costs per meter should be adjusted for inflation.

V.1.15. Energy theft

This indicator is important because it represents electricity supplied for which the utility will not be paid. This indicator should be adjusted for inflation to identify real cost trends. Levels of theft vary by country, but in the United States, theft is estimated to be .5% to 2.5% of total revenues. For a utility with $500 million annual revenues, energy theft could therefore cost $2.5 to $12.5 million per year. (This is theft only: distribution efficiency is discussed in Chapter IV.) The data source is special investigations performed by the Company. See the case study in this chapter for a more detailed discussion.

Objective: Provide support to maximize human resources

No quantitative performance indicators were identified.
ACCOUNTING PERFORMANCE INDICATORS AND THEIR USE 1/

Objective: Provide satisfactory customer service

No quantitative performance indicators were identified.

Objective: Maximize efficiency and effectiveness of the accounting function

V.2.1. Account receivable lag

This indicator measures the efficiency of the bill collection process by showing how long customers delay paying bills after they are received. If a utility receives payments steadily throughout the year, this figure is calculated by dividing the accounts receivable balance at the end of the year by the average daily revenues. If payments are not steady this calculation must be altered. When the lag is compared to the contractual time that a customer has to pay a bill, the difference indicates a potential savings figure. For example, a 35-day actual lag when the contractual lag is 20 days indicates that customers are, on the average, paying bills 15 days late. For a utility with $500 million in revenues and a 15% short-term borrowing cost, and the annual cost of this 15 day delay is $3,075,000 ($500 million/365 x 15% interest x 15 days). Because the cost is proportional to the size of the customers, this indicator should be segmented by class of customer.

V.2.2. Bad debt

This indicator measures receivables deemed uncollectable and removed from the asset balance. High percentages can indicate weak controls and follow-up in prompting customers to pay their bills which can entail significant cost. For example, for a utility with $500 million revenues bad debts amounting to only 1% translates into an annual loss of $5 million. Because different classes of customers exhibit different rates of delinquency, this figure should be segmented by classes of customers.

V.2.3. Percentage of accounts more than three months old

This indicator stratifies accounts receivable and enables identification of specific accounts that may become bad debts unless action is taken.

V.2.4. Percentage of security deposits

This indicator is important because it measures a utility's bad debt coverage. A high level of security deposits indicates that the utility is in a better position to protect itself from bad debts and accounts receivable provided the application of deposits against overdue accounts and disconnection practices are timely and consistent.

1/ Data sources for all indicators in this exhibit are the utility's financial and revenue accounting records or annual budgetary reports.
V.2.5/6/7/8. FTE staffing years/customer, FTE staffing years/kWh, overall accounting O&M Costs/Customer, overall accounting O&M Costs/kWh 1/

These indicators measure overall cost efficiency of the accounting function in terms of its driving components, customers, and kWh. Costs should be inflation adjusted. Because accounting is a service-intensive function, the use of these indicators is limited because much of accounting workload is generated by external demands.

**Objective:** Provide service support to other functions of the utility

V.2.9/10. Frequency of closing financial books and time lag from the end of the period to producing reports

An important accounting function is to produce accounting and management information quickly and accurately for all utility activities. These indicators provide some measure of accounting's efficiency.

V.2.11. Budget variances

Although the accounting function merely collects the information, the level of variance between the planned budget expenditures and actual expenditures is a useful measure of a utility's management control. This information should therefore be collected in accounting and the figure should be categorized by the utility’s various functions to identify problem areas.

V.2.12. Overall utility revenues / expenses

Although financial indicators are not included in this chapter, the accounting function must compile and provide timely information on the financial health of the utility. Overall utility revenues/expenses is one of these important measures.

**Objective:** Provide support to maximize human resources

No quantitative performance indicators were identified.

---

1/ If possible, staffing years should be based on Full-Time Equivalent Employees. Analysis is more precise if employees are categorized as (1) management, (2) skilled, (engineers and non-engineers), (3) technicians, (4) administrative and support, and (5) unskilled.
SUPPLY MANAGEMENT (MATERIALS MANAGEMENT RELATED) PERFORMANCE INDICATORS AND THEIR USE 1/

Objective: Provide satisfactory customer service

No quantitative performance indicators were identified.

Objective: Maximize efficiency and effectiveness of supply management (materials management related functions)

V.3.1. Inventory turnover

This indicator provides an overall measure of the efficiency of the materials and management function. It is calculated by dividing inventory (valued at cost) used during the period by average inventory (valued at cost). Average inventory is the average of the beginning and ending inventory. Because different classifications of inventory will vary in turnover, this figure (as well as all inventory figures) should be segmented, if possible, by the type of inventory (emergency spares, operations, and construction—with further segmenting within each of these areas for generating stations, line materials, substation and electrical controls, and consumables). When segmented properly this indicator can help identify potential cost savings. Assume a utility can increase its turnover from 1 (once a year) to 2 (twice a year). For a utility with an inventory value of $30 million and a typical annual cost to hold inventory of 30%, this translates into an annual savings of $4.5 million. (Turnover increase would reduce the inventory holding cost from $9 million to $4.5 million.)

V.3.2. Inventory levels per net revalued assets

The inventory level (valued at cost) as a percentage of the utility's net revalued assets (assets that have been brought in line with market value) is an additional tool for analyzing the efficiency of materials management. If the value net revalued assets is not available, actual plant assets can be substituted. As with inventory turnover, this figure is much more useful when it is segmented by types of inventory: Generating inventory can then be indexed by MW and MWh, and transmission and distribution inventory can be indexed by circuit kilometers of line and MWh. This indexing provides an analysis of the inventory by its driving components.

V.3.3. Percentage of slow-moving inventory (not used in the past 12 months)

This indicator identifies potentially obsolescent stock that may identify inventory control problems and stock that may potentially be sold for scrap.

V.3.4/5/6. Inventory variances, percentage of inventory theft, percentage of inventory scrapped

These three indicators provide performance measures on storage control and management. Poor control of stores often lessens efficiency of the materials management function. Poor control can also create a direct cost to the utility if theft is high or if large amounts of inventory are scrapped.

1/ Data sources for all indicators in this exhibit are, for the most part, transportation accounting records, work orders, or annual budgetary reports.
V.3.7/8/9. Average time from placing of order to receipt of material, percentage of purchase decisions based on requirements planning, percentage of inventory items not used as planned

These three indicators provide performance measures for inventory procurement, purchasing, and planning. The latter indicator would be the ratio of actual usage to forecast usage. The effective functioning of these activities greatly influences materials management efficiency.

V.3.10/11/12/13. FTE staffing years per customer, FTE staffing years per MWh, overall materials management O&M cost per customer, overall materials management O&M cost per kWh 1/

These measures provide information on the overall cost efficiency of the function in terms of its driving components, customers, kWh or MWh. Costs should be inflation adjusted. Because this area is service-intensive the use of these indicators is limited because much of the workload is generated externally.


This indicator measures the frequency of stock-outs and is a good indicator of service to other activities of the utility. If possible, this figure should be segmented by type of inventory. The next two measures provide more specific information regarding the cost and cause of the stock-outs.

V.3.15. Cause of stock-out

Stock-outs can generally be attributed to inadequate planning or to purchasing problems of some type (including supplier delays). To assist in pinpointing improvements in stock-out percentages, stock-out causes should be identified.

V.3.16. Percentages of stock-outs causing loss of power or stoppage of major projects

Each stock-out has a different associated cost. The specific cost of all stock-outs should be incorporated into the inventory planning process. This indicator provides a measure of stock-outs that had a major impact on the utility. If possible, this figure should be segmented. Also, if possible, these stock-outs should be separated into those caused by planning and those caused by purchasing.

Objective: Provide support to maximize human resources

No quantitative performance indicators were identified.

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1/ If possible, staffing years should be based on Full-Time Equivalent Employees. Analysis is more precise if employees are categorized as (1) management, (2) skilled, (engineers and non-engineers), (3) technicians, (4) administrative and support, and (5) unskilled.
SUPPLY MANAGEMENT (TRANSPORT RELATED) PERFORMANCE INDICATORS AND THEIR USE

Objective: Provide satisfactory customer service

No quantitative performance indicators were identified.

Objective: Maximize efficiency and effectiveness of supply management (transport-related) functions

V.4.2/3/4/5/6. Number of total vehicles and value per customer, per MWh; Number and value of generation vehicles per MWh; Number and value of transmission vehicles per transmission circuit km of line; Number and value of distribution and customer service vehicles per customer; Number and value of administrative vehicles per MWh, per customer

These indicators measure the number of vehicles and value by their various driving components. Using this information, potential capital savings can be identified. (Note: construction vehicles should be considered separately from operating vehicles.)

V.4.7. Operating costs per vehicle-km

This indicator provides an overall indication of the operating costs per vehicle km. If possible, the costs should be segmented by generation, transmission, distribution, customer service, and administration. This indicator should be adjusted for inflation to identify real cost trends. Analysis can pinpoint potential cost savings in areas such as maintenance.

V.4.8/9/10/11. FTE staffing years per customer, FTE staffing years per MWh, overall transport O&M cost per customer, overall transport O&M cost per kWh

These indicators measure overall cost efficiency of the function in terms of its driving components, customers, kWh and MWh. Cost should be adjusted for inflation. Since this area is service-intensive, the use of these indicators is limited because much of the workload is generated externally.

1/ Data sources for all the indicators in this exhibit are, for the most part, transportation accounting records, work orders, or annual budgetary reports.

2/ If possible, staffing years should be based on Full-Time Equivalent Employees. Analysis is more precise if employees are categorized as (1) management, (2) skilled, (engineers and non-engineers), (3) technicians, (4) administrative and support, and (5) unskilled.
Objective: Provide service support to other functions of the utility

V.4.12. Average availability of vehicles

This indicator provides a measure of service to the operating activities of the utility. A low availability results in poor service or the need for additional capital expenditures to provide a number of vehicles sufficient to support the utility's needs. Low availability is generally caused by poor maintenance or by using vehicles that are beyond their optimum service life.

Objective: Provide support to maximize human resources

No quantitative performance indicators were identified.
HUMAN RESOURCE PERFORMANCE INDICATORS AND THEIR USE 1/

Objective: Provide satisfactory customer service

No quantitative performance indicators were identified.

Objective: Maximize efficiency and effectiveness of other corporate support activities

V.5.1. Training costs per employee

This indicator if it can be segmented is most useful by utility functions as well as by employees' classifications. This indicator is useful for identifying high (or possibly low) expenditures for training. It should be adjusted for inflation.

V.5.2/3/4. Average capital cost of employee dwelling, average operating cost per occupant, and vacancy rate of dwellings

These indicators provide cost-effectiveness measurements for housing provided to utility employees. By analyzing these indicators, potential cost savings can be identified. This indicator should be adjusted for inflation.

V.5.5. Overall human resource O&M cost per employee 2/

These indicators measure overall cost efficiency of the function in terms of its driving component—employees. Costs should be adjusted for inflation. Because this area is service-intensive, the use of these indicators is limited because the workload is generated externally.

Objective: Provide service support to other functions of the utility

V.5.6/7. Percentage of training hours per total labor hours, percentage of full-time employees exposed to training for one week or more

These indicators provide a measure of training provided employees. This indicator may indicate too much or too little training. The indicator does not measure the quality of training.

1/ Data sources for all indicators in this exhibit are for the most part, personnel records or annual budgetary reports.

2/ If possible, staffing years should be based on Full-Time Equivalent Employees is more precise (1) management, (2) skilled, (engineers and non-engineers), (3) technicians, (4) administrative and support, and (5) unskilled.
V.5.8. Employee turnover

This indicator provides information on the number of employees who are leaving the company. It is calculated by dividing the number of positions vacated during a year by the annual average employed. It is an important indicator because the utility is required to train new employees to fill the vacancies. A high turnover can indicate an unacceptable level of dissatisfaction. A low turnover, however, is not necessarily good, if it indicates a complacent workforce and weak personnel policies. If possible, turnover should be segmented by employee classification.

V.5.9. Unfilled skilled vacancies

Utilities are often unable to fill skilled positions in their organization. This creates a problem because skilled personnel are critical to cost-effective operation. This indicator provides information on unfilled skilled vacancies. If possible, this indicator should be segmented by employee classification.

V.5.10. Comparative industry compensation level

Competitive pay levels are an essential factor in keeping good employees and operating cost effectively. This indicator compares the utility's compensation levels with those of other utilities and industries in the marketplace. Because the competitive marketplace may extend to all parts of a country and even beyond the country's borders, compensation levels for these areas must be included in the indicator to provide a worthwhile measure of comparative compensation. If possible, this indicator should be segmented by employee classification.

V.5.11. Percentage of corporate staff 1/

Proliferation of corporate staffing in utilities can have a negative impact on cost-effectiveness. Too often, employees migrate to staff level positions that create activity and reports but do not necessarily contribute to corporate objectives. This indicator provides information on this area.

V.5.12. Employee morale

A high level of employee morale is important for peak utility operations. High morale perpetuates employee commitment to achieving the utility's objectives. An effective way to measure employee morale is through employee surveys.

V.5.13. Number of accidents per 1,000 employees

Employee safety is important for employee morale and the general health of the work force. High numbers of accidents often indicate a need for better training procedures, or management guidance. This indicator provides a measure of employee safety.

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1/ Corporate staff means all those not directly involved in the production, distribution, and service to the customers and not involved in the construction and maintenance of facilities for such activity.
PERFORMANCE INDICATOR REPORTING DOCUMENT
FOR LARGE CONSUMER BILLING LAG

<table>
<thead>
<tr>
<th></th>
<th>Date:</th>
<th>Department:</th>
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<tbody>
<tr>
<td></td>
<td>Month Two, Year One</td>
<td>Commercial General Mgr.</td>
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<table>
<thead>
<tr>
<th>Large consumer</th>
<th>Performance billing lag</th>
<th>Indicator #2,#3, etc.</th>
</tr>
</thead>
</table>

I. Current reporting information

- Current operating level: 8 days
- Current target: 7 days
- Acceptable deviation: 1/4 day
- Actual deviation: 1 day
- Exception report needed: Yes
- Gain (loss) in net benefits for period: <$6,000>

II. Year end reporting information

- Originally planned target: 6 days by Month 3
- Acceptable deviation: 1/4 day
- Revised targets: 5 days by Month 3
- Exception report needed: No
- Gain (loss) in net benefits for period: <$6,000>
# ACTION PLAN REPORTING DOCUMENT FOR LARGE CONSUMER BILLING LAG

<table>
<thead>
<tr>
<th>Date:</th>
<th>Month Two, Year Two</th>
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<tbody>
<tr>
<td>Department:</td>
<td>T&amp;D General Manager</td>
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<tr>
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<td>#1</td>
<td>#2</td>
<td>#3, etc.</td>
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</table>

## I. Description of action plan
Reduce large consumer billing lag

## II. Initial estimates

- **Targets**: 2.1 days, Month 3
- **Annual net benefits**: $235,000

## III. Update of current status

- **Target**
  - **Current planned**: 4 days
  - **Acceptable deviation**: 1/4 day
  - **Current actual**: 5 days
  - **Current difference**: 1 day
- **Estimated net benefits**
  - **Current planned**: $40,000
  - **Current actual**: $20,000
  - **Current difference**: <$20,000>
- **Exception report needed**: Yes

## IV. Revised long-term estimate

- **Target**
  - **Long-term originally planned**: 2.1 days by Month 3
  - **Acceptable deviation**: 1/4 day
  - **Long-term expected**: 2.1 days by Month 3
  - **Long-term expected difference**: 0
- **Annual net benefits**
  - **Long-term originally planned**: $235,000
  - **Long-term expected**: $215,000
  - **Long-term difference**: <$20,000>
- **Revised actual plan necessary**: Yes
- **Exception report needed**: No
DETAILED ANALYSIS OF COMMERCIAL INDICATORS
FOR USE AT THE MANAGER LEVEL

This appendix provides information on commercial operations of a utility—including customer services, accounting, supply management, and human resources. The objective and performance indicators for each function are summarized in Exhibits V-1 through V-5 (Chapter V).

CUSTOMER SERVICE

The customer services function of a utility is important because it deals face-to-face with customers and because its labor intensive structure generally consumes a large portion of the utility's payroll. To understand and improve customers' perceptions of service, a utility must be aware of customers' opinions of the utility and whether the customers believe the service they receive is priced fairly. These insights can be gained through customer surveys and to a lesser extent, by monitoring customer complaints. Other measures of customer service include the weighted average waiting time for service hook-ups, the time required to complete service calls, and the percentage of service territory with electricity available.

The labor intensive nature of customer service makes measures of labor efficiency particularly important. Because the number of customers and kWh sold are driving factors behind staffing levels, indicators such as customers per employee and kWh per employee are ratios used to measure labor efficiency and to reflect overall levels of service. Operation and maintenance (O&M) costs per kWh and per customer are also important. Industrial engineering studies can provide useful indicators of the efficiency of repetitive customer service functions, including meter reading, field service activities, billing, and customer contact. Industrial engineering systems, if needed, can be developed for these areas. Such systems, however, should be structured to monitor only those activities that contribute to the function's objectives.

An important customer service objective is to process customer bills as soon as possible following meter reading so that the utility can receive payment with minimal elapsed time thereby reducing the operating cash needs and their attendant costs. The length of time for completing this function is called billing lag. It is the first step in revenue accounting (the process by which the utility sends electricity to customers and receives payment). Other steps in revenue accounting include accounts receivable and bad debts (both are discussed in the accounting section of this appendix) and energy theft (discussed later in this section). The billing lag is important because each day's lag adds additional interest costs for the utility. The billing lag is affected by meter reading efficiency, which can be evaluated with performance measurements that include time to read 100 meters (segregated by small and large users), percent of meters re-read, and meter reading costs per meter read.
The last step in the revenue accounting process—usually a responsibility of the customer service function—is energy theft, which was discussed earlier in this chapter.

ACCOUNTING

The accounting function's commercial activities include an important role in the revenue accounting process—handling accounts receivable and bad debts. Accounts receivable is best measured by its weighted average lag (segregated by different classes of customers). Bad debts are best measured by the ratio of bad debts to total revenues. The percentage of accounts receivable over three months old is also important because it identifies accounts that may become bad debts if no action is taken. Data on percentages of customer security deposits provides important information on the utility's coverage for late accounts receivable and bad debts.

Although the accounting function is not labor intensive, measurements of staff levels and overall O&M costs related to the number of customers and kWh sold can be valuable indicators of changes in labor efficiency.

The accounting function is usually responsible for producing financial reports and related budget information for the entire company. The efficiency of this process can be measured by the time lag from the end of a given period to the distribution of functionally accurate reports on the period.

The accounting function does not cause operating budget variances (except those related to its own budget), but it is responsible for reporting them. So the accounting function is in the best position to identify budget variances—a useful measure of overall management control.

SUPPLY MANAGEMENT

The supply management function is important in achieving the utility's overall cost-effectiveness and in providing support to operating activities. Supply management's activities include:

- inventory control planning and management,
- stores control and management,
- purchasing, and
- transportation.
The first three activities are part of materials management (indicators are presented in Exhibit V-3). The major objective of materials management is to keep inventory as low as possible while maintaining reliable service to the operating functions. The cost effectiveness of this area can be measured by inventory turnover and the level of inventory indexed by the amount of net revalued plant assets (if this figure is not available, actual costs should be used). Because the typical annual overhead cost of holding inventory (including interest, warehousing, insurance, losses) is approximately 30% of total inventory, the inventory level can have a significant cost impact. The percentage of slow-moving stock is another important measure because this can identify inventory control problems and can indicate stock that should be sold for scrap or the use of which is resisted because of unfounded prejudice.

Stores control, purchasing, and planning all affect inventory levels and the service provided to other utility operating activities. Performance measures of stores control cost effectiveness include inventory variances, percentage of inventory theft, and percentage of inventory scrapped. Because many other activities of a utility affect purchasing and planning, accurate performance measures for these two areas are difficult to construct. Certain indicators, however, can be useful, including average elapsed time from placing orders to receiving material, percentage of purchase decisions based on forecast requirements and percentage of inventory items not used as planned.

Materials management performance is measured by the service level and stock-out frequency, causes of stock-outs, and the impact of the stock-outs on the operating activities. Since stock-outs carry specific costs, they should be segmented according to their severity.

Transportation is an important supply management activity (presented in Exhibit V-4) because of its costs (both capital and operating). The number of vehicles can be monitored with several performance indicators whose driving component is vehicle function. These indicators affect overall capital expenditures. Operating cost per vehicle and average availability of vehicles are two of these indicators.

As with the accounting function, the supply management function is not labor intensive, but staffing levels and overall O&M costs related to the number of customers and MWh can be useful measurements.

HUMAN RESOURCES SUPPORT

The human resource support function covers a wide range of personnel support activities. Those that can be measured quantitatively include training, housing, turnover, staffing, compensation, morale, and safety. Each of these areas is discussed here.
The main objective of the training function is to provide effective training at the lowest possible cost. Although training effectiveness is indicated by a change in behavior (a difficult change to measure) the number of employees exposed to training can be measured. Percentage of training hours per total labor hours and to a lesser extent, the percentage of full-time employees in training for one week or more are two such measurements. Training costs can be measured by training costs per employee.

Some utilities provide housing for significant numbers of employees to secure effective operation of remote power plants, construction projects, or maintenance areas. Housing measurements can be complex, but some basic indicators include average capital cost of dwellings, average operating cost of dwellings per occupant, and vacancy rate of dwellings.

A main focus of the human resources function is providing personnel support to employees. Performance indicators such as employee turnover, skilled vacancies unfilled, comparative compensation, corporate staff as a percentage of total staff, employee morale, and number of accidents per 1,000 employees can assist in measuring this objective.

Although the human resources support function is not labor-intensive, staffing levels and overall O&M costs related to the number of employees can be a useful measurement.
USE OF OTHER COMMERCIAL CRITICAL PERFORMANCE INDICATORS TO IDENTIFY POTENTIAL COST-EFFECTIVE IMPROVEMENTS USING THE PI/MRS PROCESS

This appendix discusses five critical performance indicators identified in Annex V-3 that are not discussed in case studies such as: accounts receivable lag, bad debt/total revenues, inventory turnover, aggregate indicators, major changes in the indicators.

Accounts Receivable Lag. Utilities worldwide experience problems with accounts receivable (AR) lags. Many utilities make little or no effort to manage and control the lag. As with the billing lag, the savings realized from reducing the lag by only one day is the utility's daily revenues multiplied by its borrowing cost. The AR lag is also similar to billing lag in that responsibility for it is often shared by customer service and accounting. As a result, it is often neglected. It is important, therefore that a utility designate a specific position to be responsible for monitoring the AR lag.

In a recent in-depth management review, one utility identified a potential annual net savings of $2 million to $6 million from methods designed to lower the AR lag by three days. Another utility identified potential net cost savings of $9 million to $11 million by lowering its AR lag by 14 days.

A target performance level can be developed by determining the AR lag if all customers paid their bills on time. This lag can be compared with the current lag to identify potential cost savings. Methods for reducing the AR lag include:

- Setting explicit corporate target levels for the AR lag.
- Developing useful management reporting information such as stratifications by size of user and days lag.
- Developing aggressive collection techniques such as contacting customers as soon as bills are delinquent.
- Considering interest charges or late fees for overdue payments.
- Considering early payment incentives to speed up collection.

Bad Debt/Total Revenues. Bad debt is a recurring problem for utilities and is too often only monitored and is not managed and controlled. Responsibility for controlling bad debt is also often shared between customer service and accounting; a utility should therefore designate a specific position to be responsible for the monitoring of bad debt.

One utility recently conducted a management review that identified potential annual savings of $400,000–$500,000 by reducing bad debt level from .22% to .16% of annual revenues. Although this utility's bad debt percentage was relatively low even before the review was conducted, management determined that further improvements could be made.
The bad debt/total revenues percentage will vary widely according to local conditions. The Ernst & Whinney international data base shows bad debt ranging from 0.2% to 2.0%. A 1% average bad debt translates into a $5 million annual loss for a utility with $500 million in revenues.

A target performance level can be developed by surveying the bad debt percentages of similar utilities. This analysis, however, often fails to yield a valid target, because comparisons may not consider the local operating environment—the critical factor in bad debt. The analysis should therefore be extended to include various types of companies that operate locally.

Methods for reducing bad debt include:

- Developing aggressive collection techniques.
- Adding more collectors to collect bills in person.
- Adopting a policy supported by enforceable authority, of collecting deposits as standard practice or in the event of defined bad payment record such as prior to reconnection following disconnection for failure to pay.
- Considering service limiters (meter attachments that limit the amount of power that can be taken) for bad debt customers.

Inventory Turnover. Inventory control is critical because a utility with a $30 million average inventory and a 30% annual cost to hold inventory incurs annual carrying costs of $9 million. To identify optimum inventory levels, a utility should identify the level of appropriate service to users and then manage its inventory for maximum turnover.

A recent review by one utility identified potential annual savings of $50 million by implementing better inventory management techniques.

Although inventory turnover is a key indicator, it results solely from a utility's efforts to manage inventory levels. Because no two utilities have precisely the same inventory needs and requirements, inventory comparisons are not particularly useful. A utility is therefore well advised to concentrate on intracompany analysis techniques that identify a performance level and then to use the PI/MRS process to determine costs and benefits of changes in inventory practices. Because large expenditures are tied up in inventory, cost beneficial changes are usually achievable.

Aggregate Indicators/Major Changes in Indicators. In general, aggregate indicators—such as total staffing years per customer and overall O&M cost per kWh—are not useful for identifying cost effective improvements in a utility. They can be useful, however, for identifying areas that warrant further investigation—much as aggregate statistics analysis (see Chapter II) is used for the same purpose. Such indicators should be compared with year-
earlier measurements. The causes of year-to-year changes, if they can be determined, should be carefully documented for future reference.

If major changes in commercial indicators are recorded, areas that need further attention can be identified easily. Such changes should be noted on reporting documents.
Recall that the three steps of this PI/MRS element are:

- Identifying desired performance levels and comparing them with the utility's actual performance level to identify potential cost-economy and efficiency-improvement opportunities.
- Determining feasibility and cost benefits of achieving the desired performance level.
- Developing an action plan.

Each of these steps will be discussed in the case studies of billing lag and energy theft.

BILLING LAG CASE STUDY

Background. Billing lag is defined as the elapsed time between reading the meter and sending the bill. The elapsed time is a function of the speed of the billing process, and, to a lesser extent, meter-reading efficiency and meter-reading technology.

The hypothetical utility's billing lag is assumed to be eight days for small customers and six days for large customers. The lag of eight days for the small consumer includes:

- 2 days--to get meter readings from meter readers to the billing department.
- 5 days--to process meter readings and determine the customer's bill.
- 1 day--to review problem bills before sending out all bills on same day.

For the large customers' lag is six days because processing requires only three days.

The segregation of large and small customers in recording the billing lag information is important for focusing costs-saving and efficiency-improvement efforts, because the hypothetical utility's 3,000 large customers represent $200 million annual revenues, while its 3,000,000 small customers represent $300 million annual revenues. The improvement potential and resulting improvement efforts will therefore be far different for these two classes of customer.
As noted in Exhibit V-1, the annual savings from reducing billing lag by one day is the utility's daily revenues multiplied by its borrowing cost. An actual management review determined that reducing billing lag from four days to three days could produce annual savings of $500,000. In another management review, a potential annual savings of $3 million to $5 million was projected by reducing the billing lag from nine days to four days. Regardless how sophisticated a utility's billing system is, experience shows that reduced billing lag can produce substantial savings.

Identifying Desired Performance Levels and Comparing Them to Utility's Actual Performance Level to Identify Potential Cost-Effective Improvement Opportunities. Using the analysis techniques described in Chapter II, the following quantitative information is developed by the hypothetical utility: 1/

- **Intracompany Work Units**—In the utility's five divisions, billing lag ranges from 5 to 7 days for large customers and from 6 to 10 days for small customers.

- **Intracompany Management and Efficiency Study**—Management and efficiency studies indicate that, using the current work-flow structure, bill processing time should be three days for small customers and one day for large customers under ideal conditions. (Note that this is only one aspect of the billing-lag process.)

- **Intracompany Performance Indicator Analysis Over Time**—In the past two years, the utility has improved its overall billing lag from 10 days to 8 days for small customers and from 8 days to 6 days for large consumers. To facilitate this analysis, it is useful to show the changes over time graphically. This is shown in Figure V-C-I.

- **Comparable Performance Indicator Analysis Over Time**—Actual figures from the comparable survey data show an average lag of 3.38 days for the U.S. data base—ranging from 1.66 to 5.4 days—and an average lag of 14.7 days for the international data base, ranging from 2.2 to 30 days.

Each of the quantitative data analysis techniques provides useful information for utility managers to determine a desired performance level. The intracompany work-unit information shows that some divisions are doing better than others, indicating that overall improvements might be made by

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1/ For both case studies, specific numbers will be assumed to provide the information necessary for understanding the PI/MRS process. In using the PI/MRS process, however, a utility would determine this information.
GRAPHICAL PRESENTATION OF SMALL & LARGE CONSUMER BILLING LAG OVER THE LAST FOUR YEARS

LEGEND

- LARGE CUSTOMERS
- SMALL CUSTOMERS

DAYS OF BILLING LAG

YEAR 1 YEAR 2 YEAR 3 YEAR 4

TIME
shifting abilities and procedures from a better-performing division to a poorer-performing division. The management and efficiency study indicates that two days could be cut from the billing lag by addressing one aspect of the lag. The intracompany performance over time indicates that past improvements might be extended. The comparative analysis information is particularly valuable in examining billing lag because this activity is highly transferable among utilities (that is, billing processes are roughly similar in most utilities because of the generic nature of the billing function, with only the distances from meter-reading points to the bill-collection points varying markedly). The comparable utility information is therefore a good measure of the desired performance level when adjusted to reflect results of the other data analysis techniques. The desired performance level for the hypothetical utility could then, be set close to the range of 1.66 days identified by the U.S. comparative data base. Although differences in utility characteristics probably account for some of the differences in lag between the hypothetical utility and the comparable statistics, it seems clear that there is a potential cost saving in the billing lag area. Considering all the available figures, a desired performance level of two days is set for large consumers and three days for small consumers. 1/

Comparing the desired performance level to the hypothetical utility's actual performance indicates a potential for reducing the billing lag by four days for large customers and five days for small customers.

Determining Feasibility and Cost Benefits of Achieving the Desired Performance Level and Estimated Cost-Effective Improvements. The hypothetical utility would achieve annual savings of $329,000 2/ from large customers and $616,000 3/ from small customers if the desired performance level is achieved. As outlined in Chapter II, the approach used to determine if all or some of these savings are achievable, is to identify specific steps (preliminary action plans) that can be taken to move toward the desired performance level and then determine if those steps are cost effective.

The analysis is best begun by considering large customers because the potential annual savings per large customer are $110, ($329,000/3,000), while the corresponding figure for small customers is only 21c ($616,000/3,000,000). Although billing automation can affect all small customers and

1/ As noted in Chapter II, the desired performance level is only a benchmark in the PI/MRS process. The utility may well find that it is not cost beneficial to try to attain this level. A detailed investigation may also indicate that a level even better than the original target can be attained.

2/ Four (4) days lag x $200 million/365 x 15% interest = $329,000.
(Interest cost is assumed to be same as stated in Chapter II.)

3/ Five (5) days lag x $300 million/365 x 15% interest = $616,000.
produce significant savings, experience shows that the best and most immediate return is realized by first concentrating on large customers. This is demonstrated below.

The key factor in the large customer billing lag is the cost to reduce the six-day lag to the desired 2-day lag, because each 1-day reduction saves $82,250 (i.e. $329,000/4). Based on experience with other utilities and analysis of the hypothetical utility's billing lag, the following potential cost-saving actions in the various steps of the billing lag are assumed to be available:

1/ Note that the potential cost-saving actions are assumed here to be possible for the hypothetical utility. In practice, each utility would have to develop and thoroughly investigate specific cost-saving actions. These actions would be based on the utility's performance level and its own calculation of the targeted performance level. Costs incurred by the hypothetical utility in attempting improvements are assumed, to provide realism to the case studies. These costs would be adjusted by each utility to fit its own situation.

- **Meter Reading to Billing**--By investing in more labor, the lag from meter reading to billing can be reduced from two days to half a day. Meter readings should be at the collection point by the night of the day they are made. For the hypothetical utility, this is assumed to be possible by investing in three additional man-years of clerical/administrative personnel for transporting bills to the collection point. These need not be three additional full-time employees. Equivalent part-time people employed to meet peak loads (e.g., if the bills are all sent out at the end of the month). The part-time employees could be hired from outside the utility, but, ideally, they would come from other parts of the utility. Clerical/administrative cost is estimated at $15,000 annually, for a total cost of $45,000. Advances in meter-reading technology may make automatic meter reading more cost-effective for larger customers. This determination would be a function of actual labor costs for a particular utility and the size of the large customers. Assuming that the cost-saving action is achieved through the increases in labor, the benefit would be 1-1/2 days of billing lag or $123,375, for an annual net benefit of $78,375 ($123,375 minus $45,000).

- **Billing Process**--By investing in more labor, the billing process can be cut from three days to two days. The hypothetical utility is assumed to achieve this by investing in two additional man-years of clerical/administrative personnel to do the
billing. Ideally, some of these employees, as well as current employees, could be brought in the night that the meter readings reached the collection point. The previous discussion (see page 39) of part-time employees and automation applies to this cost-saving step also. Two additional man-years of clerical/administrative employees are estimated to cost $15,000/year for a total of $30,000. The benefit would be one-day reduction billing lag, or $82,500, production annual net benefit of $52,500 ($82,500 minus $30,000).

**Sending Out Bills**—By sending out bills as they are prepared, rather than waiting until all bills are ready, the lag can be reduced by 1.4 days. During bill processing (which will take two days as discussed in the previous paragraphs), large customer bills are currently prepared and then held until all of the bills are prepared and problem bills are corrected. This means, on average, half of all large customer bills can be sent after the first day of bill processing, while the other could be sent after the second day of bill processing (assuming there is no problem with the bill). An average of 10% of the bills are assumed to have billing problems that must be corrected on the final day of the process. As discussed previously, all of the bills (whether or not they are correct) are held until the final day. This is done to keep the accounts receivable follow-up simpler. By sending out bills on a rolling basis, however, billing lag can be reduced by 1.4 days. The 1.4 days lag is calculated by considering bill processing verification as one step that requires three days. (This assumes that the billing process is already reduced to two days.) If 50% of the bills are sent on the first day of this step, 40% on the second, and 10% on the third day, 1.6 days rather than the original three days. It would cost little extra money to do this because bills would be mailed as they are completed, producing an annual net benefit of $115,150 (1.4 x $82,250).

This review shows that, without significant capital outlays for automation or meter technology, the billing lag for customers can be reduced from 6 days to 2.1 days, producing a total net annual benefit of $246,025 ($78,375 + $52,500 + $115,150). Although the desired performance level of two days is almost attained, savings are less than the original estimate of $329,000 because of costs involved to produce the savings. Note that initial capital costs are minimal in this step.

This same type of analysis can be applied to small customers. Automation and meter-reading technology, however, play a significant role. In the United States, devices such as hand-held meter reading digital recorders have reduced the billing lag for small customers substantially. Although these techniques are cost-effective in the long-run, the return on the investment for required capital outlays may not be significant, and
therefore may not be a priority opportunity for utilities with a shortage of resources or where the cost of labor is low.

Billing automation programs have in most cases produced cost-effective results. Applying the same techniques as for large customers the hypothetical utility is assumed to be capable of reducing its lag from eight days to four days (this is within one day of the desired performance level), producing a benefit of $492,800 annually. This effort is assumed to require an initial investment of $50,000 (for billing programs) and annual costs of $200,000. Thus, the first year's savings would be $242,800 and savings in each succeeding year would be $292,800. 1/

With the determination that billing lag can be reduced, the utility investigates additional opportunities to decrease the lag further. Some alternatives may involve major capital outlays; for example, to install automated meter reading. By taking the approach outlined in the previous paragraphs, however, the utility can identify opportunities that can be acted on immediately. The analysis of additional alternatives may indicate that the utility can achieve a performance level even lower than originally estimated or can further reduce costs while maintaining original performance objective.

Other potential improvements should also be considered as part of the PI/MRS process. Billing frequency changes and one-time savings present additional opportunities for achieving improvements.

Most utilities bill customers monthly. If the billing is less frequent and is not subject to a non-negotiable contract, the utility should attempt to produce monthly bills (actual or estimated). This can produce significant savings.

One-time savings might be achieved by reading meters four days later than normal, but sending bills on the same day as called for under normal procedures. The effect would be a one-time in-flow of revenue generated by four additional days of revenue. The utility must, however, carefully consider a potential adverse reaction from customers if this option is undertaken.

Developing the Action Plan. An action plan is intended to formalize the specific steps (with targets and milestones) that will achieve the cost-effective improvements. A formal process establishes a plan that can be used as a guide for implementing the improvement action and monitoring its

1/ The cost-benefit analysis for both scenarios has been kept fairly simple. In practice, however, such an analysis can be complicated by such factors as phasing in of benefits, net present value of benefits, transportation costs, import taxes, capital budgeting considerations. Although this manual does not discuss analysis techniques, utility analysts should be fully knowledgeable of the intricacies of conducting cost-benefit analysis.
process. Sub-action plans based on this plan, should be developed for use below the manager level to ensure that subordinates are fully aware of steps required to implement the overall action plan.

Initial costs needed to implement the recommendations are assumed to have been identified for the action plan. Also, a phased reduction in the billing lag is assumed, producing corresponding phased savings. The utility is assumed to have been unable to identify more immediate cost-effective alternative. One aspect of the action plan, however is to investigate the possibility of using technology to reduce the lag more cost effectively. Again, the emphasis is on achieving immediate cost savings and efficiency improvements, and later investigating opportunities for greater cost-effectiveness by introducing more advanced technology.

The following discussion shows how two of the implementation steps in the action plan might be performed. The utility would, of course, perform as many steps as necessary to achieve the action plan's objectives.

- **Step 1**--Review initial feasibility and cost-benefit analysis and additional issues, and possibly revise action plan.
  
  (1) Time Frame. One month

  (2) Objective. At end of step, prepare final action plan.

  (3) Costs. One man-month of analysis time or $3,000. 1/

  (4) Benefits. Avoid an unproductive action plan.

- **Step 2**--Develop procedures using labor to reduce time from meter reading to collection at central point. Concentrate on large customers first. Also, investigate the possibility of using technology to reduce lag more cost-effectively after initial labor procedures have been introduced.

  (1) Time Frame:

    (a) For large consumers, one month to implement plan partially and two months for full implementation. 2/

    (b) For small consumers six months to implement plan partially and two years for full implementation.

---

1/ One man-month of commercial analyst time is assumed to cost $3,000. Note, these and all other costs are based on fully loaded (wages and benefits) compensation of typical U.S. utility employees.

2/ The phased billing lag reduction reflects customary utility practices.
(c) Start technology investigation after partial implementation for small consumers and complete in six months.

(2) Objective:

(a) Meet time-frame milestones for large consumers, reduce billing lag for large customers from meter reading to collection at central point from 2 days to 1-1/4 days in one month and to 1/2 day in two months.

(b) Meet time-frame milestones for small customers, reduce billing lag for small customers from meter reading to collection at central point from 2 days to 1-1/4 days in six months and to 1/2 day in two years. 1/

(c) Meet time-frame milestone for technology analysis.

(3) Start-up and Recurring Costs:

(a) Large customers--Initial and start-up costs of two man-months of analysis time--$6,000. Annual costs of $45,000 (three additional man-years of labor previously identified) will be evenly distributed throughout the year. Annual costs are reflected in net benefits.

(b) Small customers--Initial capital cost of $20,000 and start-up cost of two man-months of analysis time, or $6,000. Annual costs of $45,000 will be evenly distributed throughout the two years provided for implementation. Annual costs are reflected in net benefits.

(c) Cost of one man-month of analysis time or $3,000 for technology investigation.

(4) Annual Net Benefits:

(a) Large customers--Annual net benefit of $78,375 ($123,375 [1-1/2 days of lag] - $45,000 [annual cost]).

(b) Small customers--Annual net benefit of $80,000.

(c) Possible benefit of finding more cost-effective ways to achieve cost savings.

1/ The small customers' feasibility and costs/benefits were not previously discussed, but information is presented here to show complete steps. This is also done in subsequent steps.
A Summary Action Plan that can be used for upper management review and overall monitoring is presented in Table V-C-1.

Net Benefits of Action Plan

Net benefits, including annual costs but not initial and capital costs are:

- **Large customers**--Full annual net benefits of $246,025 will be achieved in the first year.
- **Small customers**--Full annual net benefits will not be realized until the end of the second year. In the first 12 months, one-half of the annual benefits, or $146,000 will be achieved, while realization of the full benefits would not occur until the second year.
- **Other benefits**--These include avoidance of unproductive action plans arising from the completion of Step 1, more cost-effective ways to achieve reduction of billing lag through technology investigation, and other benefits arising from addressing additional issues in billing lag.

Energy Theft Case Study

Background. Energy theft is a major problem for utilities worldwide. In the United States, for example, industry trade groups estimate that 0.5% to 2.5% of the revenue of fully integrated utilities (those providing generation, transmission, and distribution) is lost by theft. Like other utilities the hypothetical utility is assumed to have little specific knowledge of the extent of energy theft. The utility makes a rough estimate (not based on quantitative data) that energy theft costs approximately 0.25% of annual revenue, or $1.25 million annually. The utility has no formal program set up to address energy theft and it does not know the costs and benefits of pursuing the problem aggressively. In the past year, the utility collected $25,000 from customers as a result of energy theft identification.

In an actual recent management review, a utility identified annual savings of $500,000 to $600,000 that could be achieved with more effective energy theft control and identification measures. Utilities often do not attempt to control energy theft because additional expenditures are required or for social reasons. In the United States, however, utilities often realize a return of more than 100% annually on their additional expenditures in reducing theft. While these figures will vary by utility and by country, a return of even 50% on expenditures is still highly attractive.
TABLE V-C-1
SUMMARY OF BILLING LAG ACTION PLAN

Overview of Action Plan

This action plan is designed to (1) achieve immediate cost savings by reducing the billing lag for large and small customers via labor-intensive procedures, (2) investigate technology to reduce billing lag more cost effectively than labor intensive procedures, and (3) investigate additional opportunities to achieve cost savings in billing process.

Implementation Steps

- **Step 1**—Review initial feasibility cost-benefit analysis and additional issues, and possibly revise action plan.
- **Step 2**—Develop labor-intensive procedures to reduce time from reading meter to collection point. Also examine use of technology to reduce lag.
- **Step 3**—Develop labor-intensive procedures to reduce bill processing time. Also examine use of technology to reduce lag.
- **Step 4**—Develop labor-intensive procedures to reduce the time lag in sending bills to customers. Also examine use of technology to reduce lag.
- **Step 5**—Consider any other methods to reduce the billing lag.

A phased implementation for both small and large customers is planned. Large customer program implementation should be completed in two months and small customer implementation in two years. Technology investigation will be completed five months after start of project.

In one month, large customers billing lag should be reduced from 6 days to 4 days and to 2.1 days in two months. In six months, small customer billing lag should be reduced from 8 days to 6 days and to 4 days in two years. Technology investigation should be completed in eight months.

Cost of Action Plan

Initial and capital costs will be:

- $3,000 for review of the analysis in Step 1.
- $10,000 for the complete large customer implementation.
- $65,000 for the complete small customer implementation.
- $3,000 for the technology investigation.

Annual costs are included in net benefits.
Identifying Desired Performance Levels and Comparing Them to the Utility's Actual Performance Level to Identify Potential Cost-Effective Improvement Opportunities. The only intracompany information the utility has is the rough estimate of 0.25% noted above. No data is available from the survey of comparable U.S. and international utilities. For purposes of this analysis, comparable work units are not applicable and, as stated previously, the utility has conducted no internal management and efficiency study to determine the extent of energy theft. Because energy theft varies from utility to utility depending on a number of characteristics, the estimated level of energy theft and the amount that can be recovered (a figure not identified in the comparative data base) can only be based by an in-depth analysis of that utility's level of energy theft. When establishing the desired performance level, however, such an analysis is not suggested because it is rather time consuming. Thus, existing company information or comparable industry statistics should serve as a starting point to establish a preliminary desired performance level.

When determining a desired performance level for energy theft, two objectives are pursued: preventing energy theft from happening and recovering payment for stolen energy. Although not addressed in the survey of comparable international utilities, studies of U.S. utilities indicate that aggressive energy theft programs can recover 20% of estimated losses and yield $2 to $3 annually in revenue for every $1 spent. 1/ This can serve as a useful starting point.

Given the hypothetical utility's rough estimate of energy theft of 0.25% and the comparable data figures indicating a range of 0.5% to 2.5% a judgment of actual energy theft must be made. The hypothetical utility, estimates this to be 1.25%, or $6.25 million. With this estimate desired performance levels can be set:

* Recovery of 20% of estimated energy theft.
* Recovery of $2.5 for every $1 expended in the energy theft program.
* Reduction of energy theft from 1.25% to 1% through enforcement of program and customer knowledge that offenders will be prosecuted.

Determining Feasibility and Cost Benefits of Achieving the Desired Performance Level and Estimated Cost Economies Effective Improvements. If the utility's estimate of energy theft is accurate, the potential annual cost savings associated with attaining the 20% recovery rate and the 2.5 to 1 payback ratio for the estimated $6.25 million of energy theft is $750,000. If energy

1/ This is a good example of the need to consult all sources of comparable industry statistics when relying on comparable figures and not just the survey data that has been compiled.
theft can be reduced from 1.25% to 1%, this creates a potential savings (in the form of additional revenue) of $1.25 million annually.

Because the precise amount of energy theft and the possible level of recovery is unknown, actual cost benefits involved in more effective energy theft controls are difficult to determine without an in-depth analysis. It is clear, however, that large savings may be realized. The following approach is suggested:

- Conclude that there may be significant benefits from initiating more aggressive energy theft techniques.
- Perform a study to assess the level of energy theft.
- Perform pilot implementation of an aggressive energy theft program to assess recovery ratios.
- Develop a formal program to reduce energy theft.

Such an approach differs markedly from the one followed in the billing lag analysis, but is recommended when there are many technical questions to be resolved. This approach ultimately yields more information on energy theft but also produces some short-run cost savings from the pilot study. The outcome of this analysis will provide information necessary to determine the need for and to implement a full energy theft program.

Developing the Action Plan. The steps in implementing the action plan are:

- Step 1--Perform a study to estimate the level of energy theft and revise estimates of potential savings (if necessary). 1/

Techniques to estimate the level of energy theft should be applied to the utility's specific operating environment.

(1) Time Frame. Three months.

(2) Objective. Meet time frame and produce an estimate of energy theft.

(3) Costs. Three man-months of commercial analysis time, or $9,000.

1/ If estimated savings are low, the remaining steps would not be undertaken.
(4) Benefits. Better estimate of energy theft and potential savings.

* Step 2—Conduct pilot study of an aggressive energy theft program that identifies those stealing energy and recovers payment for stolen energy. Elements of the program could include:

--Develop a prosecution program.

--Training meter readers to recognize and identify energy theft.

--Training energy theft specialists.

--Randomly reassigning billing/collection staff.

--Conducting independent field checks, especially of large customers.

--Initiating good public relations, emphasizing cooperative approach and uniform and equitable enforcement.

--Improving metering and service line construction to reduce opportunity for theft.

(1) Time Frame. Six months.

(2) Objective. Meet time frame and produce a report outlining the pilot study efforts and recommendations for future programs.

(3) Costs. Estimated to be 36 man-months of commercial analysis time (6 analysts working full time for 6 months), for a cost of $108,000.

(4) Benefits. Short-term benefits are unknown, but are expected to be greater than costs. Long-term benefits can be significant.

* Step 3—Based on pilot study, develop formal program for reducing energy theft.

(1) Time Frame. Two months after completing pilot study.

(2) Objective. Meet time frame and produce study that identifies the formal program and its costs and benefits.
(3) Costs. Two man-months of commercial analysis time, or $6,000.

(4) Benefits. Potential to achieve the estimated additional $1.95 million annual revenue collection.

The Summary Action Plan is Presented in Table V-C-2.
Overview of Action Plan

Develop formal program to reduce energy theft by studying energy theft in more detail and conducting pilot implementation of an aggressive energy theft program. Record revenue recovery and implementation costs to assess benefit ratio.

Implementation Steps

* **Step 1**—Perform a study to estimate the level of energy theft and revise potential saving estimate, if necessary.

* **Step 2**—Conduct pilot implementation of an aggressive energy theft program to assess ratio of revenue recovery to cost.

* **Step 3**—Based on pilot study, develop formal program for reducing energy theft.

These steps should be completed in 11 months.

Cost of Action Plan

$123,000 (analysis time).

Net Benefits of Action Plans

Short-term benefits are unknown, but expected to be at least greater than cost. Long-term benefits have potential to reach $1.95 million annually.
SURVEY RESULTS COMPILING COMPARATIVE COMMERCIAL PERFORMANCE INDICATORS FROM SELECTED UTILITIES AROUND THE WORLD 1/

DEFINITIONS OF GRAPHS/TABLES

To ensure proper interpretation of these values, they are defined as follows:

* **Minimum Value** - The lowest data point of the frequency distribution.

* **Maximum Value** - The highest data point on the frequency distribution.

* **Mean Value** ($\overline{x}$) - The average—computed as the summation of data observations divided by the total number of observations.

* **Standard Deviation** (Sd) - A measure of the data variation around the mean value computed as:

$$ Sd = \sqrt{Var(x)} $$

Where

$$ Var(x) = \frac{\sum (x_i - \overline{x})^2}{n} $$

1. **Non-Generation Employees**

   Average Number of Customers

   A. **Non-Generation** - Includes transmission, distribution, customer service, and administrative and general staffing. Total non-generation employee is the summation of:

   --Management
   --Skilled
   --Support
   --Unskilled

2. **Average Inventory (Excluding Fuel) Value**

   Revalued Plant Assets

   Inventory is valued at cost. Average inventory is the average of a year's beginning and ending inventory. If possible, segment inventory by

1/ See Chapter II for a discussion of survey methodology.
A, B, and C below. If it is not possible to segment, provide the best stratification available.

A. Operation and Maintenance Stores – Excluding Fuel: 1/

---Generation
---Line Materials
---Substation and Electrical Controls
---Other

B. Construction Stores:

---Generation
---Line Materials
---Substations and Electrical Controls
---Other

C. Spares – Inventory needed for emergency purposes. (Capitalized items that are needed to repair a major breakdown somewhere in the system. These are not normally used unless a major component is about to fail or has already failed).

D. Revalued Plant Assets – Assets whose book value has been brought in line with market replacement value.

3. Turnover of Inventory (Non-Fuel)

A. Inventory – Defined above (valued at cost).

B. Turnover – Inventory (valued at cost) used during the period divided by average inventory.

4. Billing Lag

The number of days after meter reading until the time the customer bill is sent.

5. Accounts Receivable Lag in Days

The intent of this measure is to determine the number of days between invoicing customers and receiving payment. It is calculated by dividing the accounts receivable balance at the end of the year by the average daily revenues (total revenues billed in representative period divided by number of days in that period).

1/ Those used routinely for maintenance of installations and plant.
6. Write-Offs
   Revenues

   A. Write-Offs - The amount of receivables deemed uncollectable and removed from the asset balance.

   B. Revenues - Total operating revenues.

INDICATORS

The following figures are attached:

- Figure V-D-1: U.S. Generic Performance Indicator - Non-Generation Employees per 1,000 Customers
- Figure V-D-2: U.S. Generic Performance Indicator - Billing Lag (in Days)
- Figure V-D-3: U.S. Generic Performance Indicator - Accounts Receivable Lag (in Days)
- Figure V-D-4: U.S. Generic Performance Indicator - Percent Uncollectable Revenues
- Figure V-D-5: International Generic Performance Indicator - Non-Generation Employees per 1,000 Customers
- Figure V-D-6: International Generic Performance Indicator - Billing Lag (in Days)
- Figure V-D-7: International Generic Performance Indicator - Accounts Receivable Lag (in Days)
- Figure V-D-8: International Generic Performance Indicator - Percent Uncollectable Revenues
FIGURE VD-1

U. S. Generic Performance Indicator

INDICATOR: Non-Generation Employees per 1000 Customers

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<td>14.6</td>
<td>5.1</td>
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NON GEN EMPLOYEES

DATA DISTRIBUTION
FIGURE VD-2

U. S. Generic Performance Indicator

INDICATOR: Billing Lag
(In Days)

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BILLING LAG

BILLING LAG DATA DISTRIBUTION
FIGURE VD-3

U. S. Generic Performance Indicator

INDICATORS: Accounts Receivable Lag
(In Days)

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AVG. COLLECTION

DATA DISTRIBUTION

MEAN = 30.81
FIGURE VD-4

U.S. Generic Performance Indicator

INDICATORS: Percent Uncollectable Revenues

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<td>0.11%</td>
<td>2.61%</td>
<td>0.55%</td>
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UNCOLLECTIBLES DATA DISTRIBUTION
FIGURE VD-5

International
Generic Performance Indicator

INDICATOR: Non-Generation Employees per 1000 Customers

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<td>21.0</td>
<td>5.8</td>
<td>5.3</td>
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NON GEN EMPLOYEES

NON GEN EMPLOYEES DATA DISTRIBUTION
International
Generic Performance Indicator

INDICATOR: Billing Lag
(In Days)

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<td>2.2</td>
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BILLING LAG

BILLING LAG DATA DISTRIBUTION
FIGURE VD-7

International
Generic Performance Indicator

INDICATOR: Accounts Receivable Lag
(In Days)

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AVG COLLECTION

DATA DISTRIBUTION

(mean = 34.56)
FIGURE VD-8

International
Generic Performance Indicator

INDICATOR: Percent Uncollectable Revenues

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<td>.14%</td>
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UNCOLLECTABLES

MEAN = 0.14%
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