1987 IN PERSPECTIVE

1987 has been a successful year for PTI. We have maintained our controlled growth objectives while continuing significant development in our software products. New models of machine end loads for dynamic studies, an advanced transmission planning methodology, and techniques for maintenance scheduling have been successfully developed and applied. A major developmental/experimental project on six- and twelve-phase transmission, funded by the U.S. DOE, ESEERCO, and NYSERDA was completed, and an operational prototype six-phase transmission line on a utility system is anticipated in the near future. Our educational services have expanded by six new courses, with over 40 courses presented by PTI.

Our software products have seen release of Rev. 16 of PSS/E and planned release of a major new product — Relational Data Base (RDS/E) — in April of 1988. The PSS/E load flow has been integrated into the operational software, as well as a new and faster state estimator. A dozen new PSS/E sites have been added in 1987 and PSS/U sales were the highest ever.

In our specialty hardware, the all-digital power system stabilizer, introduced by PTI in 1985 and universally applicable to any generator, has become a well-accepted technology, rapidly replacing the analog devices. Recent advances include expanded data acquisition functions, on-line tuning, and selectable operating modes based upon electrical power, accelerating power, or machine internal slip frequency. Another major hardware project was initiated when PTI was engaged by Toshiba Corp. of Japan for design and construction of a major portion of their new HVDC simulator.

Our Technology Assessment Group completed a major EPRI-funded project resulting in application guides for temporary operation of induction and synchronous machines following coil failure. A major new service — “Introspect” — is now being offered by TAG under license from the General Electric Company. This service — a productivity enhancement method through the use of quantitative and objective information — is consistently used throughout GE and has been applied by both GE and TAG to a number of other major corporations.

PTI has opened an office near Sacramento, California (One Sierra Gate Plaza, Suite 340B, Roseville, CA 95668, Tel. (916) 783-3585) to provide better service to our Western clients. Harrison Clark, formerly Manager of Utility Systems Performance at PTI in Schenectady, manages the office which has a full complement of computer facilities to accommodate all PTI software. The staffing level will increase as the western area workload grows. Through this office, we look forward to even closer association with our many clients in the West.

Three major management changes occurred in 1987. F. P. (Paul) de Mello became a Principal Consultant and Don Ewart replaced him as Manager of Consulting Services. Charles Moskov joined PTI as Manager of Sales, a new position.

As we look to 1988, everyone in PTI wishes to thank you, our clients, for a successful 1987. We commit ourselves to continued service to you in the coming year.

President

COST/BENEFIT ANALYSIS OF DISTRIBUTION AUTOMATION

J.J. Burke,
Manager, Distribution Engineering

The concept of distribution automation has been with us for well over 20 years. It has been touted as a means to improve system reliability, improve losses, control voltage, manage loads, read meters, etc. While any of these functions might have significant value, it has generally been agreed, for the past 20 years, that only a combination of several functions will make distribution automation economically feasible. (See Figure 1).

Since utilities must pay for these functions, it is necessary to estimate how much (in dollars) each of them might be worth. If, for example, reliability is looked at as the most important function but has a low payback, the utility faces a dilemma. PTI has, over the years, evaluated many areas in which automation might be applied to ascertain which areas deserve the most attention. Some of the areas studied are:

- Savings associated with increased reliability
- Savings due to loss reductions caused by optimal feeder configuration
- Savings due to optimal feeder switching
- Savings due to better equipment utilization.

Many of the effects resulting directly from interruptions are relatively easy to assign a dollar value. Other direct impacts such as reduction of manpower efficiency, fear, injury and loss of life are difficult to quantify. Indirect effects such as civil disorder during blackouts or

(Continued on Page 2)
COST/BENEFIT ANALYSIS OF DISTRIBUTION AUTOMATION
(Continued from Page 1)

Figure 1. Automated distribution control system showing communication between master computer and RTU’s and the location of RTU’s.

businesses moving to areas with higher reliability tend to be even more difficult to predict and evaluate.

If a utility is concerned only with the lost revenue costs, then the value of increased reliability due to automation might be calculated as follows:

Assume:
- load factor = .5
- 1 fault/feeder/year
- 75% reduction in outage time due to automation (average duration = 2 hours)
- 10 cents per kWh

Average MVA per feeder = 10 x .5 = 5.0 MVA/feeder

$750.00/year/feeder

On the other hand, the cost of an outage to many utilities is high. For example, one survey estimated the cost of a distribution outage to be approximately $1.50 per kW of connected load. Assuming an average substation size and feeder area, it has been shown that automated sectionalizing could save over $20,000 per feeder per year.

Losses due to IPR leading on the distribution system can amount to tens of thousands of dollars per feeder, on an annual basis. It proves interesting to study the impact of distribution automation, specifically automated switching arrangements, on feeder losses. The primary question to be answered is “can feeder losses be reduced by incorporating automatic switching, and if so, is the economic impact significant?”

Feeder configurations most amenable to loss reduction are those where substantial load cycle differences exist. Such would be the case for the three-feeder, two-substation configuration shown in Figure 2. In this example, two feeders, one residential and one industrial, are supplied by the substation on the left. Load cycles for the two feeders are quite dissimilar, with heavy industrial loading during the day and residential loading peaking during the late afternoon, early evening period.

Computer analysis of this system indicated that line losses were very sensitive to individual feeder loading. While the best circuit arrangement for heavy loading was found to be the normal configuration, the optimum arrangement for light loading was where the last 25% of the residential load is put on an industrial feeder.

For the three-feeder configuration investigated, total annual maximum savings due to reduction in line losses afforded by automated switching three feeders were approximately $4,000 per year.

Remote switching of shunt capacitor banks based on constantly updated data has become a possibility with the advent of distribution feeder automation. Remote switching offers the possibility of a finer degree of voltage and var control in response to changing feeder loading conditions.

To evaluate the true benefit of distribution automation for capacitor switching, the automated scheme must be compared with a presently available switching scheme and fixed banks must already be sized and placed optimally. To have compared automated switching with no switching at all would be unrealistic. Studies at PTI have shown that automation can save up to $2,000 per feeder per year over a standard current controlled scheme. Studies by others have shown much higher values.

One major area mentioned where automation might have the greatest benefit is in the area of equipment utilization. Many substation presently in use and proposed do not expect to ever reach a point where conversion to a higher voltage or major expansions are necessary. In existing systems which are reaching serious loading conditions, major systems changes such as reconductoring are necessary to accommodate new load or unavailability of land, etc., and automation may be very valuable. For example, one utility studied had a choice of either reconductoring or implementing automation to allow reconfiguration of load, etc., during critical periods. Results of this analysis showed that the approximate savings by delaying reconductoring by the use of automation was $63,000 per feeder per year.

The table shown below illustrates the range of savings a utility might expect to find as a result of automation:

<table>
<thead>
<tr>
<th>Feeder Basis</th>
<th>Low Estimate</th>
<th>High Estimate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Optimized Capacitor Switching</td>
<td>$750</td>
<td>$22,500</td>
</tr>
<tr>
<td>Reduced Losses by Reconfiguration</td>
<td>473</td>
<td>2,000</td>
</tr>
<tr>
<td>Better Equipment Utilization</td>
<td>0</td>
<td>1,333</td>
</tr>
<tr>
<td>Total Annual Savings</td>
<td>1,223</td>
<td>88,833</td>
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</table>

As can be seen, most feeders are probably not very good candidates for feeder automation where dollar savings are the primary consideration. There are, however, conditions at many utilities where large dollar savings can be obtained if the critical areas of savings are properly identified and evaluated.

1988 STORM DISASTER MANAGEMENT/WEATHER TECHNOLOGY ASSESSMENT WORKSHOP

PTI has announced that its third annual workshop related to weather impacts on electric utilities has been scheduled for June 7-8, 1988, at its headquarters in Schenectady. Conceived and organized by Phillip D. Falconer, a certified consulting meteorologist and Technology Assessment Group associate, the primary theme of this year’s workshop will be Storm Disaster Management for Electric Utilities. Speakers from selected utilities will document their companies’ storm preparedness and service restoration planning process. Also on the agenda will be reviews of contemporary storm detection technology, weather information processing methods, and forecast techniques.

For further registration details, please contact either Mr. Falconer at (518) 346-7898 or Joanne Vazzana at (518) 374-1220.
UPRATING TRANSMISSION LINES

D.A. Douglass, Manager, Overhead Transmission Systems
J.R. Stewart, Senior Consultant

The need for additional power transmission capacity has traditionally been met by construction of new lines and substations at ever increasing system voltages. In recent years, however, it has become difficult to obtain both permission and right-of-way for new facilities. At the same time, annual load growth rates of 5% to 10% have given way to growth rates of 1% to 2% in some areas. At these lower growth rates, a 10% increase may be more appropriate than a 50% to 100% increase in line capacity. Such marginal increases in line capacity can be accomplished by a wide variety of low cost methods. This article discusses some of these options and the evaluation of their respective advantages and disadvantages.

Some uprating methods — such as reinforcing or replacing structures and restraining the line with a larger conductor to increase its thermal capacity — yield large increases in capacity but require relatively large capital investment in construction and material. Other uprating methods — such as the use of weather dependent dynamic thermal ratings — may require less capital investment but require more sophisticated operating procedures. Still other methods such as operating the line at a higher voltage without increasing the interphase and phase to tower clearances may result in improved system stability and thermal capacity at relatively low capital cost but require considerable technical sophistication to ensure safe and reliable operation.

The selection of an optimum uprating method for a given line requires knowledge of operating procedures, transmission system needs, and a thorough understanding of the mechanical, electrical and environmental limits on the line. It does little good to find a great way to increase the thermal capacity of a line when the system problem is one of stability. Similarly, it does little good to plan the reconductoring of a line that cannot be taken out of service. The figure below illustrates the major steps in a study leading to the uprating of an existing transmission line.

1. IDENTIFY SYSTEM NEED
2. EVALUATE CONSTRAINTS ON LINE
3. SELECT WORKABLE UPRATING ALTERNATIVES
4. PERFORM ECONOMIC COMPARISON
5. SELECT OPTIMUM UPRATING METHOD

The first step in line uprating is to determine what is causing the present limitation: Is it maximum power flow, voltage control, stability, or reliability of service? Is the need for base load or peaking (or perhaps emergencies)? Is it seasonal? Is it localized to a specific area or is it spread over large areas of the system?

The second step is to identify the limits both on the present line capacity and on any uprating procedure: can the existing lines be taken out of service for modification or reconstruction? Can live-line work be performed? Are electrical losses of concern? Is structure rebuild cost prohibitive? What is the condition of existing line structures and foundations? Are they capable of bearing the additional weight if reconstructed? Is voltage increase limited by tower window air gap spaces? Can switching surge over-voltages be limited by preinsertion resistors in the circuit breakers? Are structures sufficiently robust to allow addition of a second conductor per phase? Do operational procedures allow dynamic conductor ratings?

Next, specific uprating alternatives must be selected based upon the system needs identified in the first part of the study, the constraints itemized in the second, and a knowledge of what options for uprating exist. Sometimes new equipment and procedures remove previously existing physical constraints. Synthetic insulators have superior contamination performance and lighter weight than porcelain suspension strings and can be used to withstand greater voltage stress in the same space. Novel conductors may resist aeolian vibration or ice galloping, allowing an uprated line with less sag and lower phase clearances.

Line uprating alternatives are then evaluated economically and the least cost solution defined, although it is recognized that the optimum economic solution may not be chosen for other reasons such as reliability and safety. The major economic factors that must be identified are: predicted load growth; predicted energy and demand charges; structure rebuilding costs; maintenance of equipment; economic dispatch effects; circuit outage costs; engineering or research costs; measures of operating complexity; and estimates of the consequence of predictive failures — what if the load predictions are wrong?

Finally, all the information accumulated in the preceding steps must be evaluated in terms of long term and short term transmission planning and operational goals. System needs often change precipitously with fuel costs, the coming on line of co-generation, and the wheeling of large power blocks by neighboring systems. However, increasingly sophisticated tools and new types of conductor, insulation and substation equipment combined with careful analytical studies can help utility planners meet their system needs at minimum cost.

THE STATE OF THE ART IN POWER PLANT MAINTENANCE SCHEDULING

(Continued from Page 1)

Scheduling software

World Engineer

SYSTEM DATA
FORMULATES PROBLEM IN TERMS OF OPERATING AND FEEDING CONSTRAINTS
DETECTS INCIDENTS AND PROBLEMS
FORMULATES PROBLEM IN TERMS OF OPERATING CONSTRAINTS
DETERMINES INCIDENTS AND PROBLEMS
FORMS OPTIMAL SCHEDULE
DOES NOT LINE DIAMETER MODIFY CONSTRAINTS?
MODIFY OPTIMAL SCHEDULE
LINES SCHEDULED UNTIL OPERATIONAL AND MAINTENANCE REQUIREMENTS SATISFIED
MODIFY SCHEDULE WHEN OPERATIONAL CONSTRAINTS MODIFY FORMULATION
MODIFY FEEDING CONDITIONS, MODIFY SCHEDULING DATA
MODIFY OPTIMAL MODIFIED SCHEDULE
AND DO ON.

Several computer programs have been developed to generate "optimal" maintenance schedules. Twelve utilities did the scheduling manually, but a majority of these were actively exploring possibilities of using computer programs to do maintenance scheduling. The trend towards using computer programs seems to have been accelerated by the need to justify maintenance schedules to the Public Service Commissions.

Though the utilities are seeking to use computer programs which will generate "optimal" schedules, a commercially available maintenance scheduling program that finds true optimal schedules was not found. Commercially available maintenance scheduling programs currently use either heuristic (procedures) or dynamic programming to generate maintenance schedules. Although proponents of heuristic methods (e.g., "fill in the valley" methods) often claim their schedulers find "optimal" schedules, these claims are not strictly accurate. Dynamic programming is limited by the "Curse of Dimensionality". Due to this inescapable curse, methods that were bravely conceived as applications of dynamic programming invariably are forced
to resort to some sort of sub-optimal approximations that reduce the dynamic programming solution to a heuristic solution. Heuristic and dynamic programming approaches may fail to find the optimal solution and may also fail to find a feasible solution even when one exists.

A number of the utilities surveyed are acutely aware of the limitations of computer algorithms based on dynamic programming. Some have noted that the so-called "optimal" schedules found were extremely sensitive to the manner in which the generating units were grouped. One published example describes use of a successive approximations dynamic programming algorithm in six tests on one problem. Each test used a different rule to guide the search. For example, in three cases the units were ordered sequentially, in the other three cases they were ordered in groups. Furthermore, the units were ordered in increasing size, decreasing size, or at random. In two cases the program wrongly concluded that there was no schedule that satisfied the constraints. In a third case it found what the authors considered to be a "poor" schedule and in three cases it found schedules that the authors considered "good". It is to be emphasized that the problem presented to the computer program was identical for all six trials. The point of concern is that the user has to live with "poor" schedules if a particular rule does not work for his system.

One of the utilities surveyed reported that the dynamic programming algorithm found the best solution when all the units were put in a single group. However this led to enormously long execution times. This is exactly what the curse of dimensionality predicts!

Other concerns expressed by the utilities surveyed include the problems of maintaining enormous quantities of data that are required by some power plant maintenance scheduling programs, the difficulties in modeling inter-area transmission constraints, problems in modeling replacement energy costs and inaccuracies in load forecast data.

This survey convinced PTI of the industry need for an advanced and mathematically optimum maintenance scheduling system. PTI's convictions are shared by a number of utilities. Wisconsin Power & Light is providing partial funding for PTI to develop a new maintenance scheduling system. An advisory committee of four utilities is guiding this development.

References

### SPECIAL NOTE
The analysis of nozzle calibration data to ascertain the suitability of a nozzle for accurate flow measurement is a service that PTI routinely offers. The curve in the previous issue of POWER TECHNOLOGY was based on the calibration of a nozzle designed by PTI for the Electric Power Research Institute, Project Numbers 1681 and 2153. PTI regrets neglecting to mention the source of the calibration data and extends its sincere apology to EPRI.

### SHORT COURSE SCHEDULE — SPRING 1988
The following courses are to be presented at PTI offices in Schenectady, NY

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<thead>
<tr>
<th>Date</th>
<th>Course</th>
<th>Fee (per participant)</th>
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<th>Course</th>
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<tr>
<td>March 14-18, 1988</td>
<td>Power System Scheduling &amp; Operation</td>
<td>$1000</td>
<td>May 2-6, 1988</td>
<td>Power System Dynamics</td>
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<tr>
<td>April 11-15, 1988</td>
<td>Underground Cable Systems</td>
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<td>June 1-3, 1988</td>
<td>Harmonics &amp; Power Factor Improvement</td>
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<tr>
<td>April 16-22, 1988</td>
<td>Dynamic &amp; Control Analysis Techniques</td>
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### SPECIAL PRESENTATIONS

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<tr>
<td>Feb. 22-26, 1988</td>
<td>Power System Dynamics — Denver, CO</td>
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<tr>
<td>Mar. 2-4, 1988</td>
<td>Least Cost Planning — Integrating Supply &amp; Demand — Orlando, FL</td>
<td>$850</td>
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<tr>
<td>Mar. 28-Apr. 1, 1988</td>
<td>Power System Scheduling &amp; Operation — San Francisco, CA</td>
<td>$1000</td>
</tr>
<tr>
<td>May 9-11, 1988</td>
<td>Least Cost Planning — Integrating Supply &amp; Demand — Columbus, OH</td>
<td>$850</td>
</tr>
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</table>

For further information/registration contact: Barbara E. White, Power Technologies, Inc., P.O. Box 1058, Schenectady, NY 12301-1058, Telephone (518) 374-1220.