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Distribution Automation Applications of Fiber Optics

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PREFACE to the 2008 EDITION

This report is a reprint of a report written in late 1988, almost 20 years ago. It has been translated from the software originally used (WordPerfect) into the current JPL standard (Microsoft Word), the figures have been redrawn, and the document re-formatted. Apart from fixing a couple of minor typographical errors, the original material is presented as it was originally written. The only change occurs in Section 4.2.2 where a footnote has been added commenting on the choice of circuit parameters in an example based on a paper of Jim Burke.

The original 89-10 report described work performed at the Jet Propulsion Laboratory under the auspices of the United States Department of Energy on the technology of distribution automation. These days, the same kind of things are lumped together and called “Smart Grid.”

Because this new edition of the report has not been updated, some of the assumptions are out of date – technology improvements have changed costs, and lifted bandwidth constraints on much of data communications. Nevertheless, a good deal of the original work remains valid. In particular, the technique of doing a system-wide communications traffic study is still appropriate, and the ideas of calculating the Net Present Value of an investment are still good, though the method is these days embodied in the process of “making the business case.” The case for optically-powered measurements is made stronger by the availability, these days, of ultra-low-power analog electronics, and low-power micro-processors such as the PIC.

Twenty years ago, the various distribution automation functions had been demonstrated singly, in small subsidized experiments. A major reason for the limited impact of distribution automation was that the then-available communications media were inadequate for an integrated system. Communications technology has advanced considerably with the advent of fiber optics and RF-capable integrated circuits, and the associated hardware costs have tumbled. Nevertheless, there has been little impact in the world of the utility. Distribution automation – the Smart Grid – is struggling to become reality. Piecemeal implementation still seems to be favored, with each piece paying for its own dedicated communications scheme. *Plus ça change, plus c'est la même chose.*

In the future, JPL may be again involved in energy-related work, whether it be called distribution automation, Smart Grid, or Green Power. No doubt JPL will continue to take a systems viewpoint. It is hoped that the survey in this report will prove still useful.

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ABSTRACT

Motivations for interest and research in distribution automation are discussed. The communication requirements of distribution automation are examined, and shown to exceed the capabilities of power line carrier, radio and telephone systems. A fiber-optic-based communication system is described that is co-located with the distribution system and that could satisfy the data rate and reliability requirements. A cost comparison shows that it could be constructed at a cost that is similar to that of a power line carrier system. The requirements for fiber optic sensors for distribution automation are discussed. The design of a data link suitable for optically-powered electronic sensing is presented. Empirical results are given. A modeling technique that has been used to understand the reflections of guided light from a variety of surfaces is described. An optical position-indicator design is discussed. Systems aspects of distribution automation are discussed, in particular the lack of interface, communications and data standards. The economics of distribution automation are examined.

ACKNOWLEDGMENTS

The work described in this report could not have been done without the contributions of a large number of people. Ken Klein, Director of the Office of Energy Storage and Distribution of the United States Department of Energy, deserves special mention. Ken has had an interest in distribution automation for a long time. His financial support began the whole effort, and his continuing involvement, guidance and support helped us maintain momentum.

The authors would also like to thank Kate Meehan, a friend, for allowing business to intrude on a social relationship. Kate is CFO of the Weingart Center in Los Angeles, and she made some useful suggestions in the area of economic comparisons – does distribution automation pay for itself? We acknowledge the help of Shannon Jackson at JPL. Shannon played a major role in building the prototype hardware described here, and in optimizing the designs in a number of ways. Also at JPL, Eddie Hsu continued to be an asset to the project. His skill with computers translated into both circuit board designs and a number of useful programs. We acknowledge the efforts of Megan O'Shaughnessy, a co-op student from Cornell, who set up the apparatus to perform the reflectivity tests and made the first measurements. Finally, the authors thank Louise Anderson, our editor at JPL, for her careful and prompt reviews of the manuscript.

PREFACE

This report describes work performed at the Jet Propulsion Laboratory under the auspices of the United States Department of Energy on the technology of distribution automation.

It is the considered judgment of the United States Department of Energy and other industry observers that in the mid-1990s the United States will experience a generation capacity shortage. Several aspects of distribution automation (notably the load management and equipment utilization functions) can help ameliorate the effects of a capacity shortage. Consequently, DOE and JPL consider that involvement in this distribution automation effort is contributory to the solution of a problem of national importance.

Until now, distribution automation has only been demonstrated in subsidized experiments. There have been no commercial applications. We believe that a major reason for this is that available communications media – power line carrier, radio and telephone – have been inadequate. The demonstrations have usually started from the position that a certain technology (such as power line carrier) would be used, rather than from the position that a particular problem (such as system reconfiguration) had to be solved. It should therefore be no surprise that experiments and demonstrations have usually concluded that the communication system is the “weak link” in distribution automation.

This report includes a statement of the requirements for a distribution automation communication system. Surprisingly, this does not seem to have been studied before. In general, even a simple parameter like the data rate required for a given function is not discussed in the literature.

The conventional communications media do not meet the data rate or reliability requirements. For a successful distribution automation system, a wideband medium, configured as a local area network, is needed. Because of the demand in the telecommunications industry, the technology of fiber optics has reached the point that fibers can be economically applied to the problems of power distribution system controls and communication. A suitable fiber-optics-based communication system design that can accommodate the functional requirements of distribution automation is outlined.

In the future, JPL may be involved in the development of suitable hardware and software for the implementation of one or more prototype distribution automation systems using fiber optics. Some of that work may be industry-funded: one of the purposes of this report is to introduce potential sponsors to the JPL effort.

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Distribution Automation Applications of Fiber Optics

1. INTRODUCTION

“Broadly speaking, an electric power system can be defined to include a generating, a transmission, and a distribution system. The distribution system, on a national average, is roughly equal in capital investment to the generation facilities. The sum of these two generally constitute over 80 per cent of the total system investment. Thus, it is readily seen that the distribution system rates high in economic importance, and represents an investment that makes careful engineering, planning, design, construction, and operation most worthwhile.”

Thus begins the Westinghouse Electric Utility Engineering Reference Book on distribution systems, first published in 1959. The reality is, nevertheless, that the distribution system has not been the beneficiary of the careful engineering, planning or design that characterizes the other two parts of the utility, and its operation proceeds essentially unheeded and uncontrolled. The economics of the situation are that it has not been feasible to implement measurement or control in the distribution system to the degree possible in the generation or transmission system. The difficulty lies in the dispersed nature of the distribution system as compared with the generation or transmission system. There are hundreds of times more points to monitor, each handling perhaps only a few kilowatts.

It is a thesis of this report that there are still technical and economic impediments to automating the distribution system. We will show that these impediments can be overcome by using a communication system based on fiber optics, in an arrangement designed specifically for distribution automation.

1.1. Utilities' Interests

Both the utilities and the federal government are showing renewed interest in control of the distribution system. Each has its own reasons. From the utilities' point of view, several factors stand out. First, as shown below, an increasing fraction of the total investment of the utility is in the least monitored and controlled part of its system. Planners are beginning to see better supervision of the distribution system as leading to better utilization of capital. Capital expenditures for system reinforcements can be deferred. Under some circumstances, the implementation of control in the distribution system can even result in the indefinite postponement of system reinforcement. Second, recent advances in communications and computing technology have led system designers to the recognition that improvements are possible in their energy management systems. Better computers are available at lower costs than ever before. An improvement in the performance of an energy management system can translate into more efficient operation, and considerable economies. Third, distribution system control extensions are not usually large-scale efforts. The work can often be done piecemeal, and the capital required can be obtained in small increments.

1.2. Federal Government Interests

From the federal government's point of view, there is concern about the long-term effects of the fall in oil prices in the wake of Saudi attempts to recapture their market share, and the collapse of the OPEC oil pricing structure in the mid-1980s. Statistics show that the plunge in oil prices has led to a degree of complacency about conservation on the part of the U.S. consumer. Oil consumption is increasing, and reliance on imports continues. Domestic output is now only 8 million barrels a day, 11% lower than its 1985 peak. At present, 42% of the oil consumed in the United States is imported, and the percentage is rising ("Tax Gas," 1988). Not the least of the problems is the effect of the imported oil on America's current account deficit.

The electric utilities, and industry in general, responding like other consumers to the low oil prices, have increased their consumption of oil – by almost 18% in the year 1987 alone, according to an article in Science (Crawford, 1987). Apparently the situation has not improved in the decade since load management projects were examined under a U.S. Department of Energy program (Survey of, 1977). This report underscored the then government's concern over dependence on imported oil. Among the objectives of load management that were (and are) relevant to the national concerns listed above were shifting fuel dependency from limited to abundant energy sources and lowering reserve requirements. Both energy and capital could be (and can be) conserved.

1.3. Generation Capacity

There is another reason that the government (and some utilities) are concerned about the future and are hoping that distribution automation can help. It has been predicted that, on a national accounting, generation reserve margins will be completely eroded by the mid-1990s. This means that there will be insufficient generation capacity to meet peak demand. This situation arose because, after a brief hiatus following the 1970s oil shocks, the demand for electricity resumed steady growth and expenditures on generating equipment did not keep pace. Even allowing for the possibility that reserve margins were too high in the early 1980s, it is clear that, sooner or later, supply will not equal demand. Figure 1-1 shows the effect of different load growth assumptions on the time at which the reserve margin vanishes.

Electricity consumption rose about 3.6% in 1987. If demand continues to increase at this rate, it will exceed capacity before 1990. Even under the more conservative growth rate of 1.5%, capacity margins will be gone by 1995. It is already too late to start building new generation to alleviate the anticipated shortages: the lead time on the construction of new fossil-fired or nuclear generation stations is over ten years.

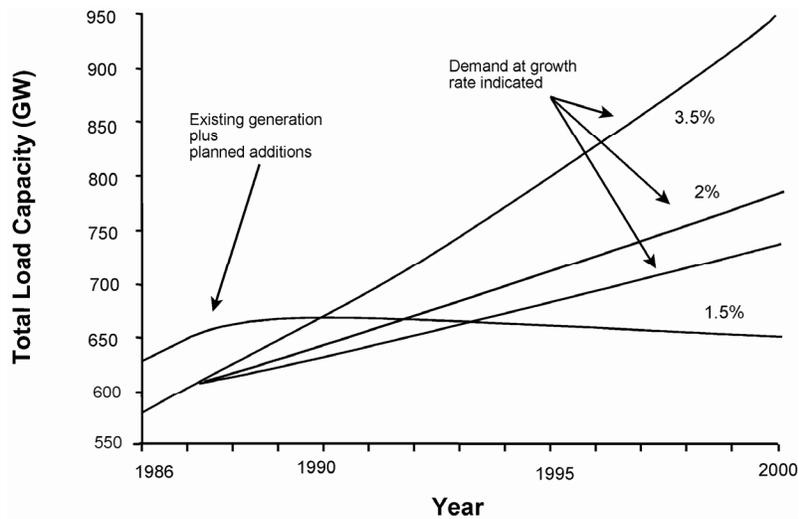


Figure 1-1. Electricity demand and capacity, according to different load growth assumptions

At the level of the state government, there is interest in conservation and cogeneration as a means of appeasing the Green movement. In what is possibly a precedent-setting decision, in January 1989 the Public Utilities Commission of Maine blocked an attempt by Central Maine Power to buy 300 MW of Canadian capacity. The purchase had been opposed on the grounds of adverse environmental impact of a transmission line that would have been constructed in western Maine. The PUC decided that the utility had not adequately explored all the conservation and cogeneration options.

1.4. A Multifaceted Solution

But, in general, the utilities are not even planning new fossil or nuclear stations. Intimidated by an uncertain or even unfriendly regulatory environment, many utilities are planning on buying power from their neighboring utilities and from independent power producers and cogenerators, and on building generation with short lead-times. They are also instituting conservation and load management programs, and extending the life of existing plants. It is hoped that this strategy of combining several partial solutions will hold the apparent demand growth to a low level, and keep the capacity at least at its present level (instead of declining, as in Figure 1-1).

However necessary, the approach is unlikely to address the problem adequately. The North American Electric Reliability Council has estimated that the United States will need about 79 GW of new capacity between 1988 and 1995 (U.S. Energy, 1988). (This would be consistent with a growth rate of between 2% and 3.5% in Figure 1-1.) Of this 79 GW, 45% is not yet under construction. If the multipronged approach to solving the generation/demand inequality is to have any hope of working, each element must make its maximum contribution. Even so, it must be presumed that the capacity problem will only become more acute over the next few years.

1.5. Motivation for Research

The beneficiaries of the decisions now being made in many utilities will be the gas and oil companies (because short lead-time generation tends to be gas- or oil-fired) and the Canadian utilities, whose export of electrical energy has been growing at an average annual rate of over 10% for the last decade (ie, almost 3 times the growth rate of electric energy sales in the U.S.).

The clear conclusion that the United States will be increasingly dependent on oil (largely imported), natural gas and imported electricity is disturbing to many. There is a possibility that our continued reliance on imported oil and electricity will lead to a larger current account deficit, and a weaker dollar, which will have to be propped up by higher interest rates. High interest rates hurt everyone, particularly U.S. industry.

These are issues that concern planners at the U.S. Department of Energy. Some of them are arguing for institutional changes¹, to restore to the utilities an environment in which economical base-load generation again becomes possible. This would mean changes in rules at the state and federal level, including rate-making and construction financing. More efficient regulation, with fewer delays in construction, could save billions of dollars in carrying charges.

Meanwhile, the technical options have not been fully explored. It is hard to see how the efficiency of generation or transmission could be improved, but distribution systems have been the “poor relation” of the industry for so long that it is inconceivable that improvements could not be made there. Therefore the U.S. Department of Energy has, for several years, been funding advances in the state of the art of distribution automation.

Other than for experimental or demonstration purposes, no utility has implemented a truly automated distribution system, yet. Nevertheless, some visionaries anticipate a highly automated distribution system by the end of the century (Caldwell *et al.*, 1982). Indeed, compared with other aspects of utility spending, distribution related investment seems set fair for the future. If this future is to include better operation and monitoring of equipment, it will require a better communication system than any now available in the distribution system.

¹ “The utility industry has served the nation well for over a century. But the fact is that utilities are reluctant to undertake new construction to meet future needs. No new orders have been placed for nuclear plants since 1978, and there is little evidence of major base load construction involving other fuels. . . . If we are to avoid future capacity shortages, and to maintain reliable sources of supply, it is imperative that we look at ways of improving our current regulatory system and the incentives – or disincentives – we currently give to power producers.” Martha O. Hesse, Chairman, Federal Energy Regulatory Commission, before the Electric Power '89 Conference, Washington, DC. Reported in DOE This Month, January 1989.

1.6. Overview of the Report

1.6.1. Section 2: The State of the Art Distribution Automation

The severe cost constraints that result from the large number of measurement and control points in the distribution system have meant that most of the distribution system is not monitored or controlled in a closed-loop manner. The addition of closed-loop control to an existing distribution system necessarily implies additional communications, either to the distribution substation or the energy control center. The inadequacy of the available communications systems has been one of several impediments to the widespread use of distribution automation. Field trials and demonstrations have been limited in practice by the communication system used. This report therefore begins by examining the communication requirements and capabilities of the various aspects of distribution automation. It is concluded that a technically adequate and economically sensible communication system using fiber optics can be built for distribution automation.

Some details of the implementation of such a fiber optic communication system remain to be worked out, and will be part of the development effort of future years. For example, a power distribution system typically has the topology of a tree network, with any physical ring circuits electrically open. The system is operated radially. A communication system designed for distribution automation would have to be capable of reaching all parts of the distribution system. Must it not also, then, have a tree-like topology? While fiber optic communication systems have been designed in the past to use several different topologies, such as star, ring, or bus, it is not immediately obvious that a tree configuration would best suit the application. An arrangement of interconnected rings, similar to the topology of a distribution system with all its breakers and switches closed, is more appropriate. Details of how communications traffic is handled on such a network remain to be worked out.

It is shown, even without solving all the detailed design problems, that the economics are favorable. Some examples are given. The power utilities are in the fortunate position of being able to take advantage of the price impacts of the competition for the fiber optics business of the long-distance telephone services. Because of this, every power distribution line could be furnished with a fiber cable, and every customer accessed from a two-way communications link, for a cost that is economically attractive.

The goal of this part of the report is to describe a distribution system communication and control system capable of implementing any or all of the wide variety of functions that are usually grouped under the heading of distribution automation. When completed, the work whose start is described in this report could be key to the creation of a multimillion-dollar industry in distribution automation applications of fiber optics.

1.6.2. Section 3: Fiber Optics for Distribution Automation

Fiber-based sensors are commonly thought to be of wide applicability in power systems because of their inherently insulating nature and their immunity to electromagnetic noise. For some while now, JPL has been developing fiber optics and fiber optic sensors for power system applications. In 1984, fiber optic applications to power systems were reviewed (Kirkham, Johnston, Lutes, Daud and Hyland). In 1986, fiber-based sensors were reviewed (Johnston, Jackson, Kirkham and Yeh), as a preliminary to the development of measurement of power line electric and magnetic fields (Kirkham, Johnston, Jackson and Sheu, 1987; Kirkham and Johnston, 1988). The references in these reports show that there are several groups, in England and Japan as well as in the United States, developing optical measurements for power system quantities.

In general, the sensors developed have been aimed, not unnaturally, at the measurement of current and voltage. Commercially, the optical current transformer has the greatest potential. At high voltage, a significant fraction of the cost of a current transformer (CT) is the insulation. An optical current transformer, on the other hand, does not need to be insulated from the high-voltage conductor provided the output either is a free-space link or uses fiber cables that can be electrically stressed. It is therefore possible, in theory at least, to manufacture an optical equivalent of the current transformer at greatly reduced cost.

However, the current transformer in a high-voltage substation is expected to be accurate over a wide range of currents and temperatures. The dynamic range of some optical measurements is limited, and the materials typically used in an optical sensor are temperature sensitive. As an alternative approach to implementing an optical CT, our group at JPL and at least one manufacturer have (independently) developed low-power optical telemetry for conventional CTs. By electronically encoding the reading on a conventional CT, and by powering the electronics optically, the “optical” CT is made to seem passive. It thus retains all the advantages of a true optical CT, without the dynamic range and temperature problems.

To facilitate the development of this kind of measurement in the distribution system, this section of the report presents an optically powered data link for general-purpose, low-cost application. The link has moderate bandwidth (1 kHz), accuracy (1%), and dynamic range (>60 dB) – performance parameters that should be adequate for most distribution system applications. While these are analog specifications, the link uses a frequency modulated optical pulse train to retain noise immunity and insensitivity to changes in the fiber loss characteristics. The approach could be used with any of the usual electrical or electronic measurements: current transformers, strain gauges, thermocouples, etc. As an example, results are presented showing current measurement by means of a linear coupler.

This work is an offshoot of earlier work done at JPL on the measurement of power line magnetic fields. Another sensor described in this section of the report is also an offshoot of our field measurement work. In the probe of our dc electric field meter, an optical pulse is generated each time the probe rotates through a reference position. In the early versions of the field meter, the pulse was generated by reflecting light off a shiny spot on the edge of the rotating part of the

probe. The light was emitted by a fiber/collimator combination, and returned into the fiber after reflection. An optical directional coupler separated the returning pulses from the steady source.

Because of problems that were experienced with this system, we carried out an investigation into alternatives. At first, we planned to study a number of different reflective surfaces to see if any were significantly less sensitive to alignment. As the work proceeded, it became evident that the measurement of surface properties was not as simple as had been hoped. It was difficult to separate surface effects from the influence of the optics illuminating the surface and measuring the reflected power.

A modelling approach based on Bewley's Lattice – originally developed to study travelling waves on transmission lines – was developed to represent the optical arrangement. Implemented in Lotus 1-2-3, it provided some insight into the measurement problem. This work is also presented in Section 3 of the report.

In the end, a greatly simplified optical arrangement was developed. It is presented here as a general-purpose position indicator. The method could readily be retrofitted to switches or drop-out fuses as part of a distribution automation scheme. In these applications, it has the advantages of being inexpensive and inherently insulating.

1.6.3. Section 4: System Considerations

The communications links and the sensors are components of a distribution automation system. If the impact of distribution automation is to be felt, that is, if distribution automation is ever to go beyond the subsidized demonstration stage, there must be analysis and design at a system level. We consider that the lack of engineering at this level is one of the impediments to the widespread adoption of distribution automation.

There are many reasons for the present state of affairs. Equipment manufacturers are generally organized along component lines. One company makes sensors, another makes communications hardware. Neither of these makes switchgear or transformers. The utility company that buys components for a distribution automation system is faced with a large system-integration task. For example, in his summary of the results of the distribution automation project at Athens, TN, Markell (1987) began the discussion of results to date by saying that problems had been encountered with interfacing the monitoring and control equipment from different vendors and with designing mounting configurations and installation procedures.

Contributing to this problem is the almost total lack of any standards for interfacing the various bits of hardware. Standardization could occur on many levels: the instrument interfaces, the communications protocols, the connectors used. It has occurred on none of these.

This section of the report begins by examining the standards that have been written in other (related) industries: consumer electronics and industrial electronics. Some of the issues that are relevant to the question of standards in distribution automation are discussed.

The question of standards is always one of striking a balance between limiting technology development by too early a freeze on designs, and hindering market development by allowing conflicting designs to compete for the market. An example of the first is NTSC television (known in most of the world as Never Twice Same Color). In the second category must be included AM stereo, stillborn because of the FCC's unwillingness to choose between the four competing systems.

It seems that there is a way out of this dilemma for the interface question. A proposed method of solving the interface problem for an optical measurement is to interpose a "black box" between the optical sensor and the utility. The interface between the sensor and the black box is designed to suit the sensor, whereas the interface between the black box and the utility can be standardized. Thus, if the transducer is an optical one, the interface is an optical interface. If the transducer is electronic, the interface could be radio or electronic or an isolation transformer. The technology is not limited. On the other hand, because the second interface is standardized, the development of the market is encouraged. The black box becomes the responsibility of the sensor manufacturer to produce. But, because it will be built to a standard, it can be interfaced to any other of the utility's equipment built to the same standard.

The other impediment to the adoption of distribution automation in the utility industry is the poorly understood economics of the situation. All too frequently, we read papers and reports with expressions like "This function alone has the capability of paying for the automated distribution system," with no supporting economic analysis. Certainly, engineers are not accountants. But we must recognize the importance of a good economic justification for what we do. One is reminded of the utility planner who was asked, during the recent flurry of interest in high-temperature superconductivity, whether he could design a loss-free transmission system. "Certainly," he replied, "but my accountant won't let me build it." Wise accountant.

The section ends, therefore, with an economic analysis of distribution automation. Load management is frequently motivated by considerations of capacity shortage, and several convincing analyses have been presented in the past. Some of these are reviewed. Automatic meter reading is often more a matter of complying with the legal requirement the utility read billing meters at least annually. The savings said to be associated with the general goals of increased reliability, loss reduction and better equipment utilization are rarely evaluated. To rectify this situation, we examine several distribution automation applications in detail and compare the savings with the costs of installing suitable automation systems.

2. THE STATE OF THE ART OF DISTRIBUTION AUTOMATION

2.1. Definitions

As the technology for implementing distribution system control has developed, new terms have been introduced into the language. Demand-side management is now the general term for the direct and indirect control of customer loads and energy storage and generation devices. Distribution automation, the unifying theme of this report, is the term used to describe automated utility control of both the load and the distribution system. Load management is now merely a subset of distribution automation.

Distribution automation functions have become somewhat of a “wish list.” Functions that are usually considered part of distribution automation may include:

- management of customers' loads
- monitoring of the performance of the power system itself
- reading of customers' meters, perhaps even several times a day
- detection of stolen energy
- control of voltage in the power system
- detection of outages
- reconfiguration of the system following a fault
- balancing of loads for optimal system operation
- collecting load data for system planning

There are a few engineers who would argue that distribution automation is a “system” and should be viewed as a complete entity in its own right. Most observers point out that several of the functions involved have no relation to one another, and accept as a working definition of distribution automation the implementation of two or more of the functions. The fact is, simply, that apart from a few trial installations, distribution automation does not exist, and so it may be defined very much according to one's own personal whim. If we accept that distribution automation is a system, then it is modular. The modules can be implemented independently and in stages.

Distribution automation has been extensively discussed in the literature, and the interested reader is able to find many IEEE Power Engineering Society (PES) papers and industry reports. Some of these are listed in a bibliography on distribution automation that covers the years 1969 through 1982, prepared by the Task Group on Distribution System Design (Buch *et al.*, 1984), part of the Transmission and Distribution Committee's Distribution Subcommittee. The text of a tutorial course that has been offered at Power Engineering Society meetings can also be obtained from IEEE (IEEE 88EH0280-8-PWR). For completeness, a brief summary will be given here.

For the purposes of the present discussion, the distribution automation system can be divided into three separate (geographical) parts: the distribution substation, including the transformers that take the power from the bulk system, and the buses and breakers that send the power out of

the station at low voltage; the low-voltage feeders and transformers, ie, the equipment up to the customer's meter; and the equipment on the customer's side of the meter, including load control equipment and customer-owned generation. Figure 2-1 shows some of the functions to be performed by the distribution automation system in these parts of the system. We will discuss the various functions according to this geographical breakdown.

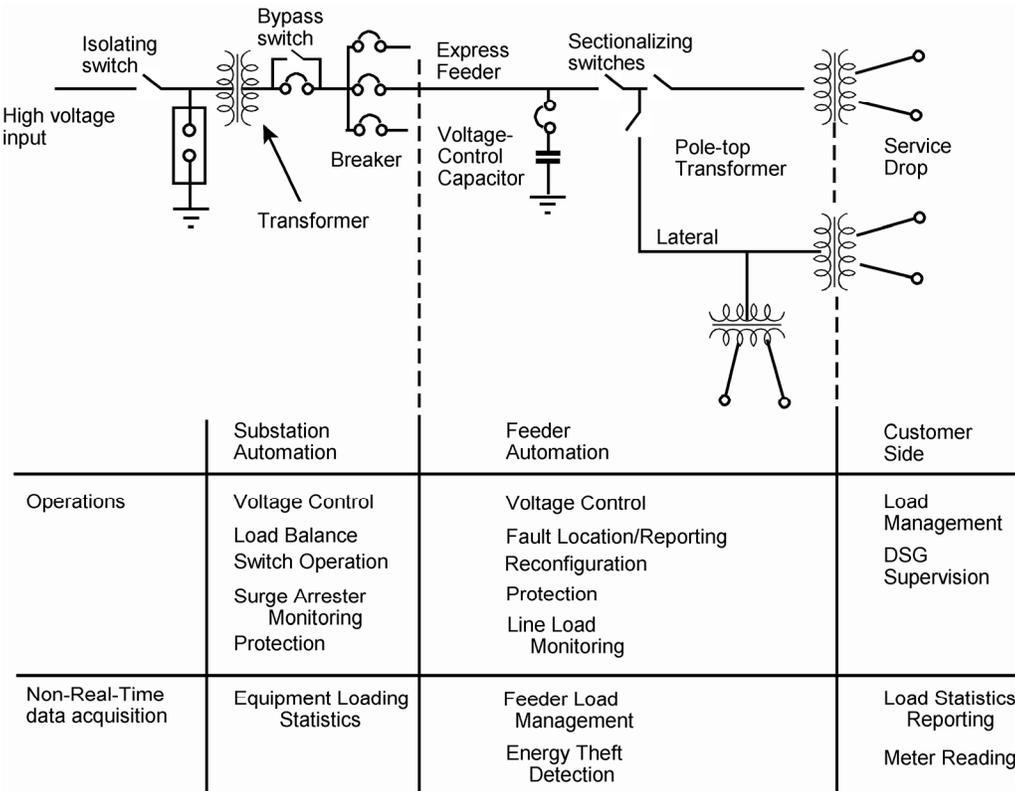


Figure 2-1. Distribution automation system functions

2.2. Substation Automation

Substation automation can improve service reliability and equipment utilization. The term is really a blanket description of a number of quite different functions that could be automated in a distribution substation. Recloser operations could be supervised, in coordination with feeder automation, load could be balanced between transformers, equipment operating conditions could be monitored and voltage controlled. Evidently, substation automation systems will need to interact with other distribution automation functions to a considerable degree. The distribution substation is a logical place to locate the hardware (in particular the computer) of many of these functions.

2.3. Feeder Automation

Outside the distribution substation, the distribution automation system can perform equipment monitoring (similar in function to substation automation) and feeder automation. Protection functions may also be included. Feeder automation, which we define as monitoring and control of the system from the substation to the customer's meter, may have many objectives. One is to increase system reliability by reconfiguring the distribution system automatically. This may be done to balance the load among different feeders, to remove the minimum amount of a system following a fault, or to restore as much load as possible after a fault has been isolated. Some of this control requires a knowledge of where the load is in terms of its distribution along any given feeder. This could be approximated ahead of time, or the distribution automation system itself could furnish the data in real time. Other feeder automation functions can only be implemented by means of real-time data input (Aucoin, Zeigler and Russel, 1985). Methods developed using artificial intelligence (AI) may be of benefit in solving the reconfiguration problem (Sakaguchi and Matsumoto, 1983).

2.3.1. Volt/VAr Control

Volt/VAr control, which could be part of substation or feeder automation, can be used to reduce losses by supplying reactive demand locally, and to improve the quality of service by more tightly controlling the customer's voltage. Even if these were the only reasons for installing a voltage or VAr control system, there would be little reason for delay if (a big if) the cost of a voltage sensor could be made comparable with the cost of a time clock. However, a closed-loop control has other advantages: for example, it could be used to supplement the load management system and provide some temporary load reduction. For this, some form of communication system, such as that provided by the distribution automation system, is essential. It may also be feasible to program the voltage control system with a set point that depends on system frequency.

2.3.2. Outage Detection and System Reconfiguration

The detection of outages in the distribution system is presently accomplished in a rather simple fashion: when the customer notices that the power is out, he calls the power company. Most power outages are caused by distribution system failures; therefore, the only information the utility has available about the majority of power failures comes from irate customers. In the sense that few power outages are life threatening, this situation is acceptable. There are, nevertheless, several reasons for improving the detection of outages. First, the utility's knowledge of the extent of the outage is presently very dependent on the customer and the telephone system. This sometimes makes it difficult to dispatch a repair crew. Second, a few outages are caused by downed lines, and downed lines do not always cause tripped circuits. There is a possibility that an outage means a live wire on the ground somewhere. There is presently no way to know this in the majority of cases.

Reconfiguration can be the logical next step following outage detection. The number of customers without power can be minimized, and the duration of the outage can be reduced. However, the value to the utility of reconfiguring can be overestimated. It is likely that the public relations value exceeds the revenue from the energy sales.

Reconfiguration can also be performed to minimize distribution system losses. However, the economics of this are rarely clear cut, and the number of instances where loss minimization can be used as a justification for additional expenditures in the distribution system are few.

2.4. Customer-Side Control

Customer-side control is represented by two distribution automation functions: load management and customer generation control.

2.4.1. Load Management

Load management is the term applied to a number of strategies for inducing the customer to defer the use of his load. This may be done by direct control of a switch at the customer's premises, or by the use of economic incentives, such as time-of-day rates. Direct control is usually a very simple technique whereby the power system operator can implement load reduction. While the control actuation itself is very straightforward, and load management is the oldest of the functions that we classify under the heading distribution automation, strategies for doing it are still being developed. Some of the issues to be addressed are discussed by Morgan and Talukdar (1979).

Technical problems include progressive load reduction, and restoration without excessive restart demand. Load management may offer an alternative to the purchase of peaking power, and can be regarded by the system operator as an alternative to spinning reserve. These were the motives, for example, for the implementation of a nationwide load management system in Sweden (Bohlin, Edvinsson, Lindbergh and Lundqvist, 1986). Both winter and summer peaks can be reduced by load management techniques (Rau and Graham, 1979; Fiske, Law and Seeto, 1981). Some economic incentives, such as time-of-day metering, have the advantage that no communication system is required between the utility control center and the customer. However, they suffer the disadvantage that more complex metering equipment is needed. In some instances the customer is unable to use his load during peak times: loads with inherent storage are required to make this approach feasible (Platts, 1979). The data needed by the system planner, who can regard load management as an alternative to the installation of additional generation capacity, can readily be accumulated by a distribution automation system.

2.4.2. Cogeneration and DSG Control

Cogeneration and DSG control imply the control of generation equipment not owned by the utility. Because of the issue of separate ownership, and because the generation is located in the distribution system, methods for its control or dispatch as an integrated part of the utility have

not been developed. Since cogeneration exists primarily because of the needs of a customer, it may be impractical or impossible to have it controlled according to the needs of the utility. In the past, it has been difficult to include cogeneration in the energy control center calculations. These are not insoluble problems, however, and they must be addressed if full advantage is to be taken of the potential benefits of distribution system generation. Most cases of cogeneration or DSG control can probably be handled by the utilities concerned under the guidance of the Public Utility Regulatory Policies Act of 1978, usually abbreviated to PURPA 210, since Section 210 is the one relevant to dispersed sources. This act was passed during the Carter administration, and was aimed at easing what was seen to be a growing dependence on imported oil. Control and protection problems were studied at a number of laboratories (Dugan, Thomas and Rizy, 1984) and, apart from a lack of communications capability, no significant integration issues remain (Ma, Isaksen and Kuliasha, 1979).

2.5. Communications for Distribution Automation

Distribution automation has been talked about for many years, yet it does not exist, except for a small number of experiments or demonstrations. We think a fiber-based distribution automation system will succeed where its predecessors have not. Since this is not an opinion that is in line with the “conventional wisdom,” we need to examine how we reached this conclusion.

The impediments to the development of distribution automation are partly technical and partly economic. Some utility engineers see distribution automation as a desirable part of their power system, yet they are not able to justify it economically. (We return to this issue later.) Those who are able to persuade their management to try a distribution automation scheme find they are limited by the capabilities of the communication system.

In a sense, the barriers to implementing distribution automation are all fundamentally economic. A more capable communications system could always be obtained if money were no object. There is no question that a communication system based on fiber optics would have the capability to handle all the communications traffic required by any foreseeable distribution automation system. It can also be shown to be an economically attractive alternative to the existing, less capable, communications systems.

In the early 1980s, JPL did a considerable amount of work on the communication aspects of distribution system control. A number of different technologies for distribution automation communications were investigated by JPL (Gilchriest, 1982) and by others (Monteen, 1979). The media studied include radio, telephone, and power line carrier, but do not include fiber optics.² Some of the results of this work are summarized below.

² JPL has been performing research in the area of fiber optic applications to power systems for several years. The work has concentrated on the sensing and measurement applications, however, on the grounds that all the significant fiber communications problems were being solved by the telecommunications industry.

2.5.1. Radio

Radio is inherently one-way, and has severely limited spectrum availability. Nevertheless, radio has been successfully used in a number of applications that come under the heading of distribution automation. It is a useful medium as far as load management is concerned. A central location (such as the control center of a utility) can perform the computations necessary to decide to turn off all the air conditioners in a given area, for example, and then send a suitably coded signal over a radio transmitter (either as a subcarrier on a commercial station or by means of utility-owned facilities) to receivers located at the customers' homes. The limitations of this approach arise because of the one-way nature of the medium. There is consequently no way to know that the signal was received and acted upon. In fact, the communications channel can be used only for this purpose, and there is no way of getting any information at all back from the customer's home to the electric utility control center. It should be remembered, however, that these are not important limitations for the load management application.

Low-power transmitters (usually VHF) have also been used to send information to the utility. For example, attached to the customers' meters, they enable the utility to implement automatic meter reading. The meter readings are transmitted on command to a specially-equipped van in a nearby street. This technology started in the gas industry, and has recently been successfully tried in the electricity industry. Once again, the medium carries very specific traffic.

Primarily because of limitations of spectrum space, radio is of very limited use in terms of distribution automation. This limitation translates into one-way communication, short distances, and relatively low data rates. The applications mentioned above overcome these drawbacks in different ways. For customer-side control, the broadcast message has low bandwidth requirements, and one-way communication is adequate. For meter reading, a very short range will suffice. For general application as the single medium for distribution automation, radio is not suitable.

2.5.2. Telephones

In principal, telephone technology may be adequate for many distribution automation applications. Telephones are two-way, and have a reasonable bandwidth. In fact, telephones have been used in several distribution automation installations, most notably the experiment in Athens, Tennessee, and the demonstration by Ontario Hydro in Canada. The results have not been uniformly favorable: it was discovered that when telephones were available, they were inadequate because of reliability and time delay problems. They were also expensive, and not always available at the desired location. These problems have meant in practice that, apart from a few specific functions, telephone communications are not suitable for distribution automation.

2.5.3. Power Line Carrier

Power Line Carrier (PLC) and Distribution Line Carrier (DLC) are methods of communicating that have been favored by the electric utilities because the equipment involved is totally owned by them and totally contained within their right-of-way. However, the information rate of a power line carrier system is very low, typically between 1 bit per second (bps) and about 50 bps. PLC is normally a one-way system that can only be used for one purpose, over a limited range.

High-frequency injection has been used mainly for open-wire high-voltage transmission line applications. Operating frequencies as high as 500 kHz have been used. Both parallel and series injection have been employed, and injection into phase wires and neutral wires has been tried. Because the lines are relatively “clean”, the transmitter power is relatively low (a few watts). Two-way communication is relatively attractive, since some of the isolation equipment can be used both for the transmitter and the receiver.

For distribution systems, low-frequency injection is usually used, because the signal propagates better through the complex distribution network as the carrier frequency approaches the power frequency. Frequencies lower than the power frequency cause higher magnetizing currents (and hence suffer greater loss) in shunt magnetic circuits (such as transformers). Higher frequencies suffer attenuation because of higher series impedances (line reactance, series reactors) and lower shunt reactance (shunt capacitors, cables). Choice of operating frequency has been a problem, and sometimes a large injected power (up to 1 kW) has been used. Part of the difficulty lies in the non-time-invariant nature of the distribution system, which has consequently been difficult to characterize (Gilchrist, 1982).

Spread-spectrum techniques offer some hope for the distribution system. Originally developed for secure (military) communications, spread-spectrum functions by dispersing the energy of any given message over a wide frequency band. In a distribution automation application, this means that the best links in a system would become a little worse, but the worst links become a lot better (Hagmann, 1988).

Also into the category of power line carrier we would place the use of step changes in the supply voltage itself as a communications medium, a technique reported recently (Weers and Shamsedin, 1987). This technique has the advantage that the equipment for the transmitters and the communication channel is utility-owned, and suitable voltage regulators may already be installed. It has three disadvantages. First, the data rate is extremely low, and, in the example given by Weers and Shamsedin, a message takes two minutes to transmit. This long time is required because it is a sequence of steps that is decoded by the receivers, and the steps must necessarily be fairly long if they are to be distinguished from the typical noise of the distribution system. In addition, tap-changing equipment is usually quite slow. Second, the frequent operation of the tap-changers must cause wear and tear on the equipment. Third, the use of voltage in this way cannot aid any other voltage-control strategy, and may actually be counter-productive.

2.5.4. Communications: Summary

It should be clear that there really is no communication channel adequate for the implementation of more than a few of the functions of distribution automation. This is the real reason that there have been only a few trials, and an important reason for the lack of commercial sales of distribution automation systems. Even the industry's own Electric Power Research Institute (EPRI) is in agreement with this judgment. In the Guidelines for Evaluating Distribution Automation (Bunch, 1984), it is observed that "A gap exists in that viable distribution communications systems for the fully automated distribution system are not available at the present time" (page 11-5).

This fact has led to the use of combined communications systems that use PLC and telephones, for example, to communicate to different parts of the system. The term hybrid is sometimes used; we have deliberately avoided this term because it implies a measure of integration that is often not present. Vendors in the PLC field may not be involved with radio systems, for example, and interfaces to control equipment may not be available for either medium. A utility that chooses a combined communication system to implement distribution automation often has to choose the combination it prefers, and perform the system integration itself. Any utility contemplating distribution automation is faced with a considerable engineering task. We shall return to this issue later.

In a paper for a panel session on automated distribution, at the IEEE Conference on Overhead and Underground Transmission and Distribution, Carr (1981) made the observation that no study comparing the information transfer needs of distribution automation with the capabilities of the various media seemed to have been published. Surprisingly, apart from some work that was going on at that time at the Jet Propulsion Laboratory, with regard to the use of satellites for utility communications (Vaisnys, 1980; Horstein and Barnett, 1981), this appears still to be the case.

A glance at the literature of power systems in general, and distribution automation in particular, reveals part of the reason. The power community seems not to speak the same language as the communications community. To choose the communication technology, the needed data rate (user requirements) and the communications channel overhead (carrier requirements) must be specified. This means that numbers describing the data rate in bits per second, an acceptable bit error rate for the data, an estimate of the diversity between the various functions and a maximum delay time for data transfer must be given. This information can then be combined with knowledge of the geography of the system, an error detection/correction scheme and a channel access protocol to define a communications system. This is undertaken later. First we review the state of the art.

2.6. Demonstrations

2.6.1. Communications

A number of companies have developed different techniques for communicating to control points in the distribution system. The systems developed have included power line carrier, telephone, and both VHF and UHF radio. Some tests on this equipment were reported. However, in 1975, in the opinion of the Electric Power Research Institute and the United States Energy Research and Development Authority (the forerunner of the Department of Energy), the reported tests were somewhat limited in terms of their establishing their potential applicability to distribution automation. A request for proposals was then issued, intending to lead to the funding of several projects to test communications for distribution automation.

Host utilities were chosen for the ability of their distribution networks to provide a representative mix of residential, commercial and rural loads. Altogether, EPRI and DOE awarded twelve contracts to manufacturers of communications equipment and host utilities. They were paired as shown in Table 2-1 (Lewis, 1981; Rhyne, 1982).

Table 2-1. Manufacturer/utility pairings

Manufacturer	Utility	Communications Type
American Science and Engineering	San Diego Gas and Electric	Power Line Carrier
Brown Boveri/Compuguard	Carolina Power and Light	Power Line Carrier
Westinghouse Electric	Detroit Edison	Power Line Carrier
Westinghouse Electric	Long Island Lighting	UHF Radio
Control Devices	Florida Power Corp	Telephone
Emerson Electronics	New England Electric System	Ripple Carrier/Telephone
General Electric	Philadelphia Electric	Power Line Carrier
Rockwell	Pacific Gas & Electric	Power Line Carrier
Harris-Darcom	Omaha Public Power Metropolitan Utilities Northwestern Bell	Telephone

The results of these various tests are summarized below.

2.6.1.1. Summary of Results

Each of the systems tested had some success and some failure. Reliability problems meant that none of the systems was an outstanding success. In general, hardware failures spoiled the

ultimate communication performance since attempts to communicate with defective hardware, or through defective repeaters, were counted as communications failures.

The power line carrier systems averaged about 85% in overall communications effectiveness. (Success was defined as an acceptable return message in response to a set of outgoing message requests. Typically, three or more outgoing messages would be generated in an attempt to obtain an error-free return message.) Communication success was higher if one allowed, say, a day to achieve communications to a particular point. With this relaxed requirement, success reached about 90% for the PLC systems.

The telephone systems performed rather better. One-way load control success rates were about 90%. The principal problem here was phones that were off-hook at the times the signal was sent. The success rate of remote meter reading, which allowed rescheduled attempts for an off-hook subscriber, was over 95%.

The radio system was also quite good, although hardware failures were a problem. Because of an algorithm that required all remote units to be polled through all possible routings, the apparent success ratio was less than 60%. However, when communication attempts through other than the nearest repeater were removed from consideration, the success ratio was above 80%.

At this point, an editorial comment is in order. In communications technology the success rate for transferring a message can be measured in terms of a bit error rate. From this can be calculated a message error rate, which depends on the length of the message and can be factored to include error correction schemes. If we consider only bit error rate, and posit that the specification of the channel does not include error correction, then a typical rate for a poor communications channel would be a bit error rate of 1 in 10^4 . This might be obtained, for example, on a telephone system. A fiber optic link might have a bit error rate of 1 in 10^9 . From these numbers it may be guessed that a 90% message error rate is very poor performance for a communications channel.

This guess would be largely correct. If the probability that a bit is in error is denoted by p , then the probability that a message will be successfully received is given by $P=(1-p)^n$, where n is the message length. For example, if the message consists of 100 words of 31 bits each and the bit error rate is 1 in 10^4 , the probability of success for the entire message is only 73%. These values are typical for power line carrier schemes. A strategy that divided the messages up into fewer words and a smaller number of bits and included an error correction scheme could easily raise this success rate to over 99.9%. Just why this was not done in the case of the communications schemes described above is not clear.

As an example, it can be shown that if the Bose-Chaudhuri code had been used, with word length still 31 bits, but now including 5 check digits, then one error per word could be detected and corrected and two errors per word detected. The effective bit rate would be lower, being about 84% of the original bit rate, but the success rate of communication would be very much higher. The chances of an undetected error occurring are extremely small. There are other error

correction schemes that could be employed. The choice should properly depend on the kind of interference that is expected on the communications channel.

A more detailed examination of the communications problems experienced in past demonstrations is given in the next section. Following this, it should be possible to complete a traffic study and derive the system requirements in a more formal fashion.

2.6.2. Distribution Automation

Load management using ripple control has been used for many decades in Europe, and a few demonstrations of the technology have occurred in the United States. For our present purposes, we define distribution automation to include more than one of the technologies listed earlier; for example, load management in combination with feeder reconfiguration or voltage control. According to this more restricted definition, there have been only a small number of demonstrations. Some of them have occurred in the United States. Among the earliest implementations was one in the mid-1970s. Duquesne Light Company in Pittsburgh, PA, implemented a distribution network control that combined several distribution automation applications (Johnson, Kissinger, Koepfinger, Stadlin and Masiello, 1975). Communications were by both utility-owned and leased facilities, ie, PLC and telephones.

Also among the earliest was PROBE (Power Resource Optimization By Electronics), a digital data acquisition system designed by General Electric in a project that was initiated in 1973. A trial installation was implemented at LaGrange Park substation in the service area of Commonwealth Edison (Groghan, Jenkins, Rushden, Bunch and Gurr, 1977). Results were described by Bunch, Chen, Jenkins and McCoy (1981).

Perhaps the most recent and well known demonstration took place at Athens, Tennessee, with the sponsorship of the DOE and, later, EPRI. The project, known as the Athens Automation and Control Experiment (AACE), was a research and development project installed in the operating area of the Athens Utility Board in Athens, Tennessee. Athens is a distribution authority that buys its power from the Tennessee Valley Authority (TVA). Initially funded by the U.S. Department of Energy, the experiment was managed by Oak Ridge National Laboratory.

The basic purposes of the AACE were to automate the distribution system and to develop strategies that improve the efficiency and controllability of the distribution system. At no point was it intended to develop communications media for use in distribution automation (Purucker, Reddoch, Detwiler and Monteen, 1985). The communications used in AACE were a combined system, employing telephones (both owned by the customer and leased line) and power line carrier. Figure 2.2 shows the communication and control system used in Athens.

The AACE was designed to accomplish five functions:

1. Load control,
2. Load profile measurement for households and individual appliances,

3. Volt/VAr control,
4. Distribution system reconfiguration,
5. Distribution system monitoring.

To accomplish these functions, customers' households and distribution equipment on the three substations and twelve 13-kV feeders of the Athens Utility Board were automated. Altogether the following equipment was automated: 2,000 load control receivers; 190 smart electric meters, which recorded household load profiles; 190 electric appliance meters, which recorded individual appliance profiles; 5 substation capacitor banks; 28 feeder capacitor banks; 2 load tap changing transformers; 5 line voltage regulators; 34 load break switches; 11 feeder breakers; and 11 power reclosers. Fifty-one feeder monitoring locations were used, and a weather station was installed.

The data acquisition installation was designed to facilitate the collection of data which would demonstrate the improvement in efficiency and controllability in the distribution system. The results of the AACE have been presented in a number of papers over the last few years. For the most recent results, see Monteen, Lawler, Patton and Rizy (1988); Reed, Broadwater and Chandrasekaran (1988); Reed, Nelson, Wetherington and Broadaway (1988); Reed, Thompson, Broadwater and Chandrasekaran (1988); or Rizy, Lawler, Patton and Nelson (1988).

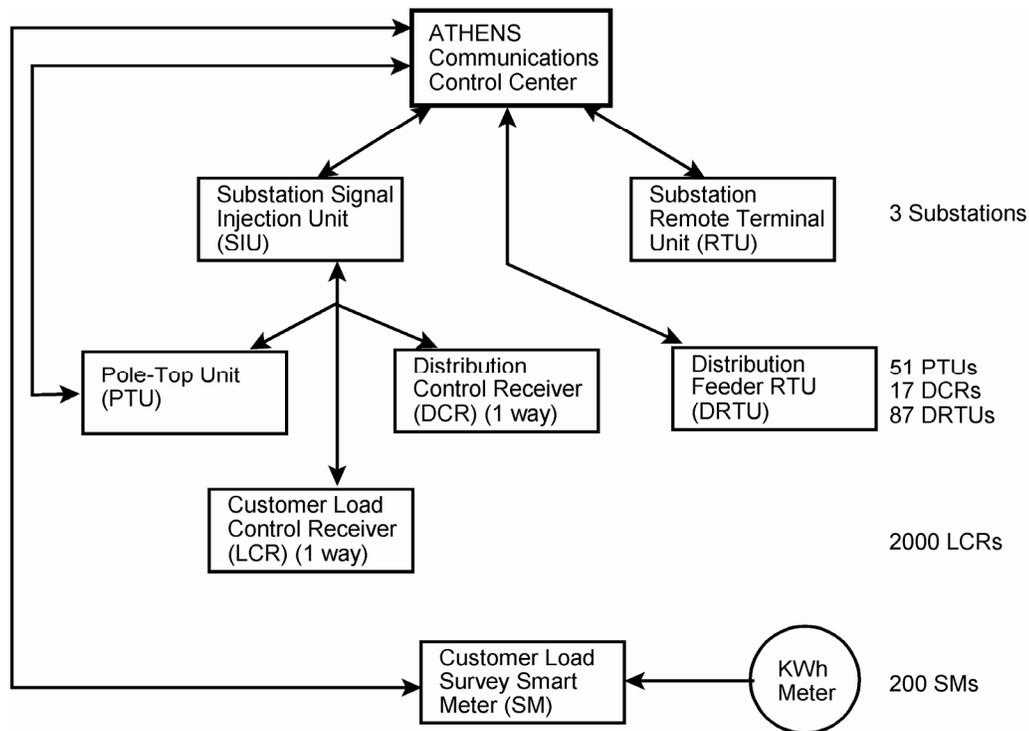


Figure 2-2. Communication and control system used in Athens experiment

As the system was being designed (and before it was installed) our group at JPL was invited to analyze the proposed communication system. This work was summarized by Nightingale and

Satinski (1984). The Athens communications system was analyzed by considering the communications between the central location of the control computer in the Athens Utility Board main office and the substation remote transponder units (RTUs), the distribution RTUs, the signal injection units (SIUs) and the various meters. For each of these links, the type of measured data that could be transmitted (such as analog values, status, or pulse accumulator readings) was considered, as well as command data. The overall time that a channel was occupied was calculated and the effect of bit errors in transmission was considered.

The result of the study was that in most respects the communication system chosen would be adequate. However, in the event that errors were incurred in transmission, or in the event that a disturbance occurred on the system which required multiple units to communicate with the central computer, the communication system was inadequate. The reliability of communication was too low, and access time to the central computer could be too long. Among the recommendations for improvement were the use of additional telephone lines, changes in the communications protocol and the use of error detecting and correcting schemes as part of the communications. In the event, these suggestions were not adopted, and the Athens project did experience some limitations because of inadequate communications.

This is not an unusual result. The distribution automation project installed in Scarborough (near Toronto) by Ontario Hydro also reported difficulties with the communications. In their case, they were particularly bothered by the reliability of the telephone system.

The Scarborough Distribution Automation Project was to demonstrate:

1. Load management
2. Automated meter reading
3. Fault isolation and service restoration
4. Load transfer
5. VAr and voltage control
6. Distribution system monitoring

The automation system was placed in service on the two 27.6/16 kV feeders of the Scarborough Public Utilities Commission. The system is described by McCall (1981). Major equipment installed included 10 overhead vacuum switches, 12 padmount switches, and 8 capacitor banks, ranging in size between 300 kVAr and 2400 kVAr. Thirty-three fault indicators and a large number of current and voltage transformers were used. Altogether, 110 RTUs were installed, 80 on distribution lines and 30 in customer premises. As at Athens, the weather was also monitored.

Preliminary results are described by McCall and Chambers (1985). Two findings are significant for our work: less costly current and voltage sensors were called for, and problems with the communications system were reported.

The communications system was selected to provide high availability and reliability, two-way communication and continuity in the event of a power line disconnection. Initially, PLC, FM radio, TV cable and telephone were all considered as candidates.

PLC was rejected after some unsuccessful performance demonstrations in situ. (One might also note that it probably would not meet the criterion of providing communications capability following a power line outage, either.) The radio and TV options were rejected on the grounds that they did not provide two-way communications. This left telephone as the only technology that could meet the requirements set out by Ontario Hydro.

Possibly influenced by another Canadian experience with telephone communications, where up to 40 seconds had been required to connect using a dial-up system, 48 circuits of hard-wired pairs were used to connect the central computer to the 30 RTUs on the distribution lines and the 80 customer RTUs. Each distribution line RTU was provided with its own dedicated circuit, as were 3 RTUs in commercial customers' premises. The remaining customer RTUs were connected in groups of up to 9 per circuit. The principal measurements were 158 current measurements, 56 voltage measurements and 107 switch and fault-indicator contact measurements.

In spite of the large number of circuits dedicated to the distribution automation system, a complete scan of all the RTUs occupied 10 to 15 minutes. The reliability of the communications system was below target too: the circuits connecting switch and breaker RTUs, capacitor RTUs and the line RTUs were unavailable approximately 0.5% of the time. Line and customer circuits were unavailable about 2.5% of the time. Failure in the telecommunication cable accounted for 45% of the total unavailable time of the system.

While the performance of the distribution automation system is adequate, improvements are needed in system availability and scanning time. It is our opinion that such improvements will not be forthcoming without considerably increased expenditures on communications, if telephone-based systems are used.

As recently as 1980, a panel session was held by the IEEE Power Engineering Society to discuss the problem of communication for distribution automation (Russell, 1980). Presentations discussed the use of VHF and UHF radio, telephones and power line carrier and came to no particular conclusion about the adequacy of any available system. It is our opinion that no currently available system is adequate. This will inevitably be the conclusion of a distribution automation demonstration.

The next section demonstrates, by means of a traffic study, why available communications are inadequate.

2.7. Traffic Study

2.7.1. Generation and Transmission System Communications

A traffic estimate for the bulk power system was performed by Horstein and Barnett (1981). They estimated the number of times data were required for various functions going on in the

monitoring and control of a power system. They estimated the number of points being monitored, and the length of messages needed to accomplish the information exchange. From this, a total utility estimate of traffic was derived.

The numbers of device status indications, alarm points and analog points were calculated to be 1850, 1729 and 770 respectively. For each of these points, the amount of data was calculated.

The polling rate was assumed to depend on the source of the data. For example, it was estimated that all AGC related functions required an update every two seconds. The same polling frequency was used for bulk power substations, circuit breakers, and status indications on a number of devices. Analog values in the transmission system were estimated to need sampling rather less frequently. Table 2-2 summarizes the estimates of polling intervals.

Table 2-2. Polling rates for data acquisition

Function	Polling Interval, s
Generation and Transmission System	
Analog quantities for AGC (Tie-line flows, generation, frequency)	2
Circuit breaker status	2
Alarms and indications	2
Internal flows and voltages	10
Tie-line energy accumulations	3600
Subtransmission:	
Breaker status	2
Flows and voltages	30
Alarms and indications	30
Non-critical system data	
Weather, transformer temperatures, etc	30

A protocol for “Automatic Supervisory and Data Acquisition Systems for Electric Generation, Power Utilization, and Power Conversion Stations”, described in an IEEE working paper (“Automatic Supervisory,” 1980), was used to estimate the communication requirements. This protocol was based in turn on the American National Standards Institute's Standard C37.1, 1979. The poll and message formats are shown in Figure 2-3. It can be seen that the information field of the response message can vary in length, so that the total message can vary between 74 bits and 266 bits.

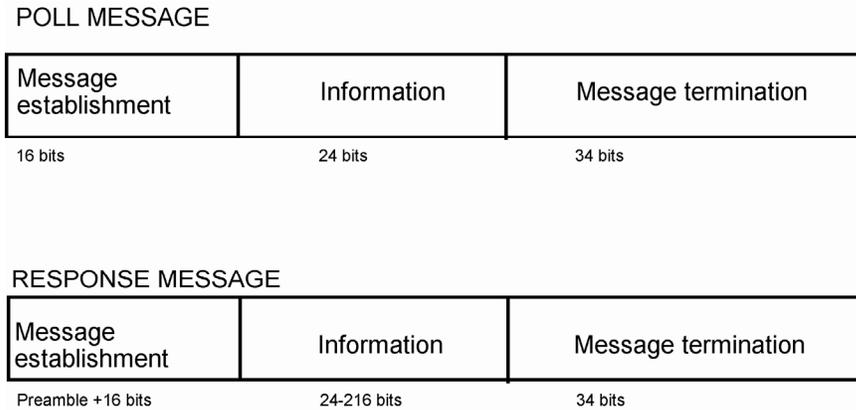


Figure 2-3. Poll and message formats used in Horstein and Barnett's study

The actual length of a specific RTU response depends on the number of data points of each type being reported. It was recommended in the Horstein-Barnett study that 12 bits and a sign bit would be reserved for each analog value, and that the data for each RTU should be considered as a multiple of 192 bits (24 bytes). This is the equivalent of 16 analog values. Although typically there might be more than 100 analog points being monitored at any bulk supply point, they probably would all not be sampled at a two-second interval. An average message length of 242 bits was chosen.

The bit rate corresponding to 770 analog points at a two-second polling interval was calculated at 4.62 kb/s. The device status and alarm points nominally require only a single bit per point, though it was suggested that some points may require a second bit. If these binary variables are also sampled every two seconds, the total bit rate is 6.4 kb/s. If the data to be reported by each RTU were actually in integral multiples of 192 bits, a composite RTU data response transmission rate would be approximately 8.1 kb/s. This might be conveniently rounded up to 10 kb/s for our present purposes.

Two minor considerations have been ignored. One is the effect on transmission efficiency of the preamble of the message, and the other is the possibility of using “report by exception” methods instead of polling. Both of these are likely to have only a very minor effect on the overall traffic communicated by the utility.

The end result, 10 kb/s, is surprisingly small. Perhaps because of this, Horstein and Barnett used another, earlier, estimate to confirm the one described here (Barnett, 1981). This estimate was based on a “synthetic utility” of 11 000 MW, roughly 1% of the capacity of the U.S. utilities. The salient features of the synthetic utility are shown in Table 2-3.

Table 2-3. Salient features of synthetic utility

Item	Number
Generating Plants	6
Bulk Supply Substations	35
Industrial Substations	40
Switching Stations	6
Intertie Lines	15
Distribution Substations	200
Meters	1,000,000
DSG Sites: Large	10
DSG Sites: Intermediate	39
DSG Sites: Small	2500

To obtain the data requirements for the utility, it was assumed that a single RTU was adequate for each distinct site, except for generating stations. There, a separate RTU was assumed for each class of generator (such as nuclear, oil, combustion turbine), with an additional RTU for the associated switchyard. Protocol and sampling rates were essentially the same as those used for the estimate described above.

The resulting traffic is shown in Figure 2-4. Response traffic was always larger than poll traffic. Generation monitoring required a data rate of 21.3 kb/s (including switching stations and bulk power stations); transmission and subtransmission totalled 19 kb/s. If these numbers are added, and the few kb/s added for control center to substation controller traffic, a figure of 45 kb/s is obtained for bulk power system response traffic. This sets the required channel capacity at 90 kb/s, assuming equal bandwidths in the poll and response directions.

The Barnett figure is nine times as great as the later Horstein-Barnett estimate. It was thought that the disparity was accounted for by the larger number of bulk power system installations in the first calculation.

Note that this is the total traffic for the bulk system of a utility of about 1 million customers.

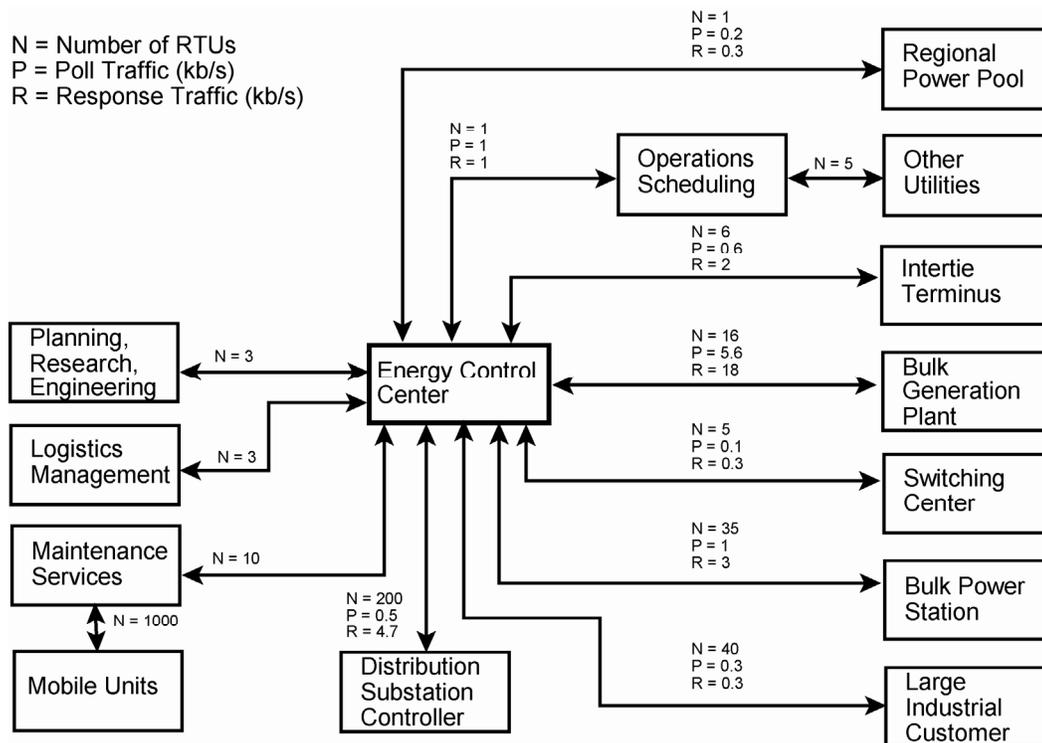


Figure 2-4. Bulk system traffic requirements from Horstein and Barnett's study

2.7.2. Distribution System Traffic Requirements

Because of the radial nature of the distribution system, the traffic calculations for the distribution system can be based on the calculation for a single (representative) substation. Applying this approach to the same synthetic utility, Horstein and Barnett arrived at a traffic estimate for the distribution system. Based on a polling rate of 30 seconds for all distribution system functions, the calculated traffic requirement was 46 kb/s. This is intermediate between the numbers obtained for the bulk power system.

The utility had 200 distribution substations, each with 6 feeders. On each of those feeders were 42 remote points to be monitored. The assumption was made in arriving at this traffic estimate that the outbound commands would be able to address all remote points at the same time. This somewhat reduced the communications requirement in the outbound direction. However, even if this is not the case, the bandwidth of the communications channel is dominated by the amount of information being returned to the distribution substation.

In round numbers then, it seems that the traffic requirement for a single distribution substation is on the order of 200 bits per second. A figure of 130 bits per second is arrived at by a detailed

calculation (6 feeders × 42 points × [242 bits/16 points]/30 seconds); a broad-brush approach (46 kb/s ÷ 200 substations) gives 230 bits per second. Let us take 200 b/s as an average number. Now, the Horstein-Barnett calculations were done for the purpose of judging the practicability of satellite communications for electric utilities. It was assumed that the time diversity between the satellite users would allow the use of an average number – not all utilities would be experiencing the kind of system problems that required increased information flow at the same time. For this purpose, an average data rate is sufficiently accurate.

To see how the peak traffic requirements of a single substation might differ from the average requirements of all substations, it is necessary to examine the problem in a little more detail. We begin by examining the frequencies of messages assumed by Horstein and Barnett for control purposes. They used the term “operational management event frequency,” with values as shown in Table 2-4.

Table 2-4 Operational Management Event Frequencies

Function	Frequency of Occurrence
Load reconfiguration	6% of feeders per day during worst-case month
Voltage regulation	Twice daily during worst-case month
Transformer management	Every 15 minutes during peak load, otherwise once per day
Feeder management	10 samples per hour during peak load, otherwise once per day
Capacitor control	Twice daily during worst-case month
Fault detection, location and isolation	1% of feeders per month
Load studies	10% of substations per year

The item described as “fault detection, location and isolation” is the key to the question of peak versus average traffic. A monthly rate of a mere 1% of the feeders from a substation is insignificant in its effect on the average. However, it can dominate the peak communications. In the Horstein and Barnett study, this was unimportant. The traffic was being calculated for a satellite transponder, with a very wide bandwidth. Time division multiplexing would have allowed any likely practical increase that was due to a distribution system fault.

However, the same cannot be said at the distribution level. If a feeder experiences a fault, it is likely that all the monitored points on the feeder should be read immediately. Using the same model as before, it can be calculated that a total of almost 1000 bits per feeder would be transmitted. It is very likely that a system operator would require information on one or two other feeders at the same substation or a nearby substation before a decision about reconfiguration could be made. Perhaps altogether 5000 bits of information would be required.

This is not an enormous quantity of data. However, since the data would have to be transmitted by up to ten pole-top remote units, the time it would take to retrieve the data would be inordinately long.

Further, one cannot but suppose that the number of measured parameters has been limited in anticipation of communication problems. A total of 42 points is inadequate to describe the state of a distribution feeder. The Scarborough Project measured over 200 analog points and over 100 contact status points for just two feeders, and it is doubtful that everything that was observable was actually measured.

Suppose that a switched tee point on a distribution feeder is instrumented. If there is a switch in each leg, it will be necessary to monitor the voltage and the current on both sides of all the switches, as well as the switch positions. This requires 39 points: voltage measurement \times 4 sides of switches (the central point is common) \times 3 phases + current measurement \times 6 sides of switches \times 3 phases + the position of all nine switches. Even with all this information, it is impossible to determine the power and reactive power, or the direction of the power flow. The addition of the necessary measurements (assuming that these quantities are to be measured rather than calculated after replicas of the waveforms have been telemetered to a computer) almost doubles the amount of data.

In practice, this is not overkill. While it is not strictly necessary to monitor the voltage or the current on both sides of a closed switch because the current through an open switch is zero, most utilities require the redundancy of this kind of instrumentation. It helps them cope with failed components and bad indications.

If the idea is to design a distribution automation system to perform a mission, rather than to design a mission that can be accomplished without advancing the technology, then it should be assumed that a distribution line will be fully instrumented. Current and voltage, real and reactive power on both sides of all phases of all switches (or circuit breakers or fuses) will be measured. Conditions on both sides of distribution transformers will be monitored, as well as internal temperature. At any given time, the operator is unlikely to want all this information, but it is shortsighted to think that there can never be circumstances in which this kind of detail is needed. The situation of the downed line illustrates the point.

A distribution line downed in a storm may not make good enough contact with the ground to cause the overcurrent to blow a fuse or trip a circuit breaker. If someone notices a downed line arcing, and has the thoughtfulness to call the utility (and can get through), it may be possible to send someone out to trip the circuit manually. But, given that there is a storm, people are unlikely to be out, and the downed line may go unobserved for some time. This situation is inherently dangerous, and utilities would like to avoid it.

Suppose that one phase of a line between pole n and pole $n+1$ of a feeder is downed and does not trip. Assuming that only tap points (transformers and tees) are instrumented, the only certain way to detect the downed line is to look for an apparent violation of Kirchoff's law at known tap points lower than pole n and higher than pole $n+1$. For example, if there is a transformer at pole

$n-1$ and a tee at pole $n+2$, current instrumentation might indicate that there was current flowing from one node toward the other that “never arrived.” If the line were energized from one side only, and the energized side were hanging in the air, there would be no fault current. In this case, loss of power on the far side of the fault would indicate the open circuit, but would not show the dangerous hanging conductor.

Software of some sophistication would be required to detect all possible faults with all possible configurations. This might be challenging, but should not be impossible. On the other hand, for this software to work, it must be assumed that all possible nodes (tap points, transformers) can be instrumented for voltage, current and power flow.

A three-phase tee at which voltage, current and power were measured on both sides of all switches would require 57 points: voltage measurement \times 4 sides of switches (the central point is common) \times 3 phases + current and power measurement \times 6 sides of switches \times 3 phases + the position of all nine switches. This is shown in Figure 2-5. It might be argued that three of the power measurements are redundant; allowing for this, the number of points is still 48. A single-phase transformer tap at which measurements were made only on the high side of the transformer (but both sides of the primary fuses) would require 13 points: voltage measurement \times 4 sides of fuses + current measurement at 6 locations (both directions of the line + high side of transformer) + 3 power measurements, as shown in Figure 2-6. If there were 100 such transformer taps, and five three-phase tees on each of the six feeders of our model utility, the total number of points per feeder would be 1585 ($100 \times 13 + 5 \times 57$). With the protocol used before, it takes 242 bits for 16 points; almost 24 kbits are required to describe the feeder. Even allowing 30 seconds for a scan, the data rate required is about 800 b/s, about 24 times the Horstein-Barnett estimate. Changing the various assumptions (scan rate, number of data points, addressing mode, communications protocol) can change the estimated data rate. However, we feel that in practice, even though few operators would require all nodes to be so well instrumented, a higher rate is more likely than a lower one, once the features of distribution automation are implemented. Our figures include no allowance for traffic that is associated with control, or is concerned with operation of the communication system itself, for example. It would probably be prudent to allow 1000 b/s per feeder, and this has the additional merit of being a round number.

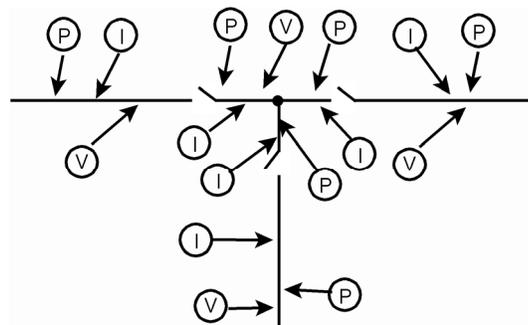


Figure 2-5. Single-line diagram of measurements at a tee point

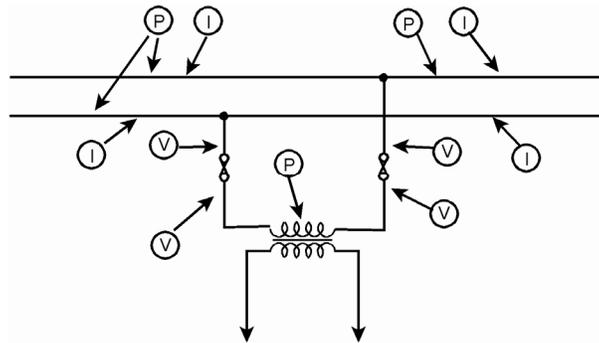


Figure 2-6. Measurement points at a distribution transformer

If the computations needed for distribution automation are executed at the substation, the data rate need never exceed the value for a single feeder. Thus, we can talk about a data rate of 1000 b/s as applicable on a feeder, and we do not need to concern ourselves with the figure of 200 kb/s for the entire utility. However, even 1000 b/s is considerably above the capability of the communication means frequently associated with distribution automation. It is orders of magnitude beyond the reach of many of the power line carrier communication methods. The number of access points is so large that ordinary telephones can be ruled out. Without fiber optics, this kind of communication system would require a dedicated telephone-grade line with the users directly connected. In other words, it would be necessary to set up a local area network (LAN).

If we are forced to consider a LAN, why not a fiber optic LAN? Let us assume, for the time being, that the question of a large number of users accessing the fiber can be solved economically. A fiber cable has the advantage that it is available in all-dielectric form. If the proper insulators are used, the fiber cable can be wrapped directly onto the distribution circuit without degrading the insulation. This means that the power conductor can be used for mechanical strength, and a less expensive cable can be used. The same cannot be said of a metallic conductor LAN, which would have to be strung separately, and would require its own strength member.

While fiber optics are normally thought of as long-distance high-bandwidth devices, particularly because of their much-publicized applications in telephone trunk systems, the fact is that even in a low-bandwidth short-distance system, fiber can make economical sense. This is an unexpected conclusion. To demonstrate the point, we compare the capital cost of a UHF radio system with that of fiber optics for the most basic application: feeder monitoring and control.

2.7.3. Fiber Optics: UHF Radio Cost Comparison

A preliminary version of a communications system for the distribution automation system can be described, based on a few assumptions.

First, we assume that the system will generally use fiber optics for communications.

Second, we assume that the distribution automation system is co-located with the distribution system, both in the substation and along the feeders and laterals, all the way to the customer's premises.

Third, since the fiber communications channel is in place, we assume that the result of a trade-off study to examine the issue of centralized vs decentralized control would indicate an advantage to centralization at the distribution substation. (Normally, such a trade-off study would examine the effect on system cost and performance of increasing the amount of distributed computer power and decreasing the communications system. Since we are assuming a communication system of considerable capability, it seems reasonable to suppose that the remote nodes need be little more than tap-points and repeaters.)

These assumptions are in line with our earlier calculations for data rate. With these assumptions, it is possible to define an outline of the proposed distribution automation system. The general approach and the system functions are as shown in Figure 2-7.

Note that in Figure 2-7, the fiber is co-extensive with the power system. Where the distribution system branches, the fiber cable branches. Every place on the power system that something “happens” (a switch, a transformer or a voltage control capacitor, for example) there is a monitoring or control point on the fiber system.

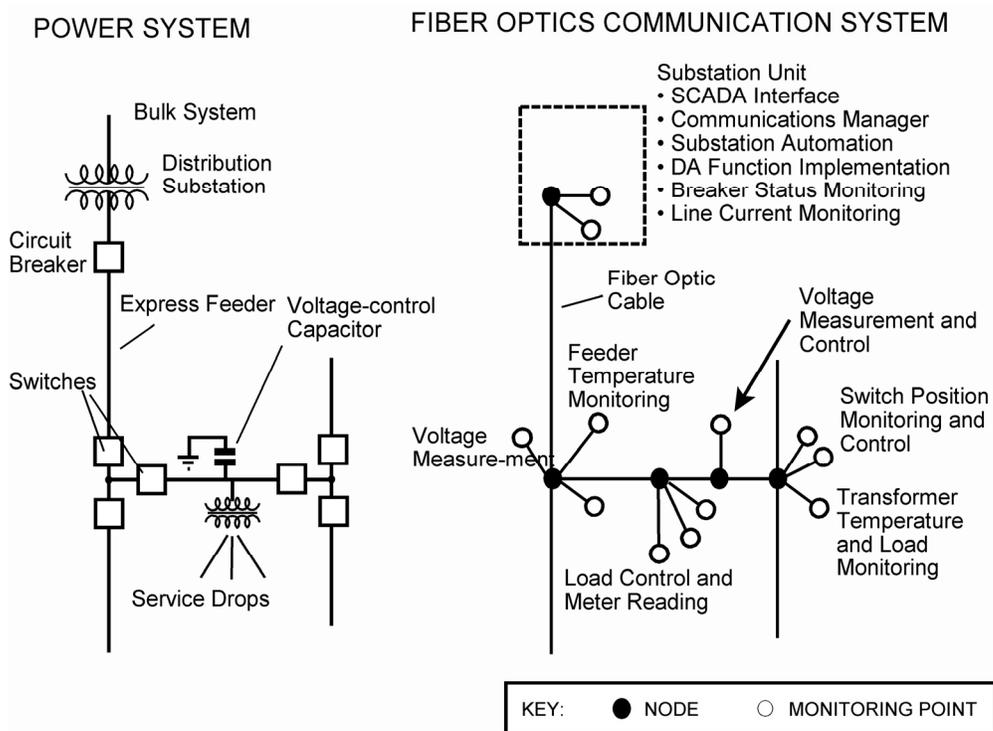


Figure 2-7. Distribution automation system with fiber-based communications

A satisfactory feeder automation system can be based on the use of UHF radio. Low-power UHF radio, operating at ≈ 950 MHz, can provide two way communications for line-of-sight locations. The bandwidth available is not as impressive as the frequency might imply, but signalling rates up to about 10 kb/s can be achieved.

No physical line modifications need be made to the distribution system in order to use UHF radio. For feeder automation, a radio is installed at all control or monitoring points; capacitor banks, switches etc. This contrasts with the fiber optics situation, in which a new component, the fiber cable, must be added along the physical line to each point at which communications are desired.

For either communication system, capital costs are of the form:

$$\begin{aligned} \text{Cost} = & (\text{transmitter cost}) \\ & + (\text{distance}) \times (\text{receiver cost}) \times (\text{number of receivers per unit length}) \\ & + (\text{distance}) \times (\text{channel cost per unit length}) \end{aligned}$$

The costs may be compared on a per circuit basis. For the sake of argument, assume the costs (in dollars) per circuit shown in Table 2-5:

Table 2-5. Cost comparisons: UHF radio and fiber optics

Parameter	UHF	FO
Central unit cost	5000	1000
Remote unit cost	1500	150
Channel cost, per meter	-	3

In this comparison and those that follow, the costs of both the fiber optics hardware and the “conventional” communications equipment are meant to include that portion of the costs of a unit that can be ascribed to the communications function. The analyses presented here are not meant to be exact. The purpose is rather to indicate that under some quite realistic circumstances a fiber optics communication system is competitive in cost.

It has been assumed that a receiver for monitoring or control for feeder automation is installed on average every kilometer along all feeders. It is assumed that in the case of the UHF radio system, the central unit costs are higher than the remote unit costs because of the need for better equipment and better antennas. The results of the cost comparison as a function of distance are shown in Figure 2-8.

The cost lines are almost parallel. In this case, the greater cost of the UHF radio equipment is approximately equivalent to the cost of the fiber for the assumed distance (1 km) between remote units.

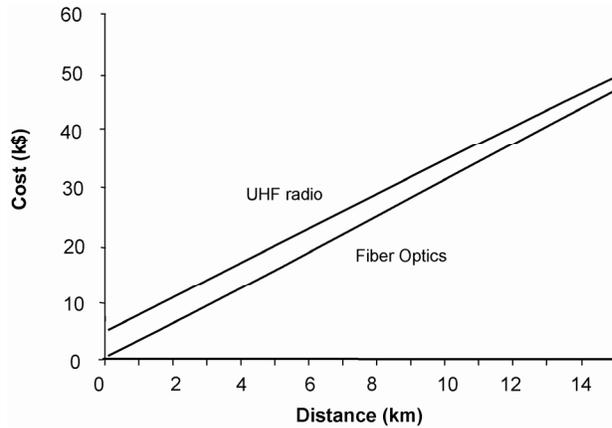


Figure 2-8. Comparison of costs for UHF radio and fiber optics communications

2.7.4. Load Management

Next, we compare the costs of adding load management in a residential area, or some such low priority function that can be accomplished with a slower, low-bandwidth system.

Load management would not seriously challenge the signaling capabilities of either the UHF radio system or the fiber optics system. The utility could choose to add load management by adding UHF receivers at every metering point, but it is much more likely that they will add a separate DLC system. DLC functions by injecting signal energy into the distribution system from the substation. Thus, it reaches all parts of the distribution system.

For the sake of comparison, we assume the costs shown in Table 2-6 apply:

Table 2-6. Cost comparisons: DLC and fiber optics

Parameter	DLC	FO
Transmitter cost	1000	-
Receiver cost, per customer	200	80
Channel cost, per meter	-	1

The communications portion of the fiber optic system is assumed to be a little lower in cost than that of the two-directional transceiver used for the feeder automation system above. The load management unit attached to the fiber on the feeder must, like the feeder automation unit, be a repeater. We assume that one such receiver is added at each pole-top transformer, serving perhaps 3 or 4 customers. It is also necessary to add a second (simpler) receiver at each

customer's premises. A less expensive fiber cable has been assumed for the short distance along the service drop. If the cost of the communications link along the service drop is considered part of the receiver cost, it is clear that the cost per customer is independent of the number of customers per kilometer, just as it is with the DLC system.

If we assume an average value of 15 m for the length of the service drop, we can compare the cost of the two options. The results shown in Figure 2-9 are for two assumed numbers of customers per kilometer along the distribution circuit.

The line representing fiber optics is less steep than the line for DLC because the cost per customer, which includes the cost of the receiver plus the cost of the fiber required to cover the service drop, is slightly less than the cost of the DLC receiver. With a large number of customers per unit distance, this difference can be considerable.

The difference in cost is even more striking when two-way communication is considered and when the bandwidths are included in the comparison. A state-of-the-art PLC system might have a 50-bps data rate, whereas fiber optic systems over the distances considered here have achieved rates approaching 10 Gbps, a ratio of more than 10^8 . It would be fair to say that the various distribution automation functions, considered together, could not utilize the bandwidth available with fiber optics. It would also be true to say that most of the functions singly would exceed the bandwidth available with PLC, and that any two in combination would certainly require additional communications capability. Fiber optics might seem like overkill, but PLC is inadequate.

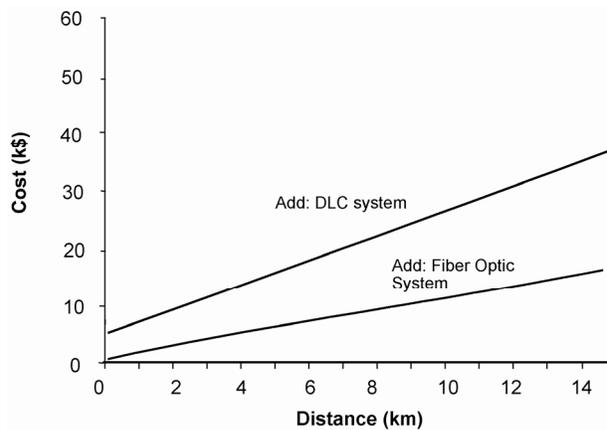


Figure 2-9. Incremental costs for DLC and fiber optics communications

2.8. Topology of a Fiber-based Network

Based on the requirement that the distribution automation system be able to reach anywhere on the power system, it is possible to define the general configuration of the communication system. The topology of the fiber communication system is governed by the configuration of the

distribution system, indeed, the fiber cable may even be wrapped around the conductors of the power network. While the power system is operated radially, it is customarily built as a series of open loops. There is almost always an alternative way of bringing power to any given feeder, if the right switching operations are done in the system. The fiber can, of course, cross an open power switch. This means that the fiber optic communication system is arranged not as a conventional ring, star or bus system, but as a series of interconnected loops, with an occasional spur. An example is shown in Figure 2-10.

This is an unusual topology for a fiber-based communication network, and one whose possibilities and problems have not been thoroughly explored. There are a number of questions that must be answered regarding the large number of taps into the fiber, and the frequent splitting of the circuit. In addition, a communications protocol that enables each distribution substation to avoid interfering with its neighbors must be developed.

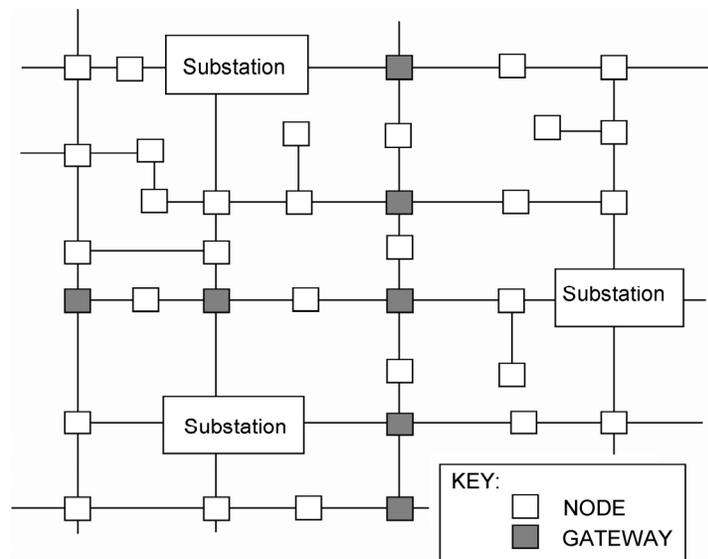


Figure 2-10. Representative topology of fiber-based communication system

A key to the distribution automation system is the node at the distribution substation. It is here that the system control and data acquisition are accomplished, and here that the intelligence resides. The functions and interfaces of the node at this location are shown in Figure 2-11.

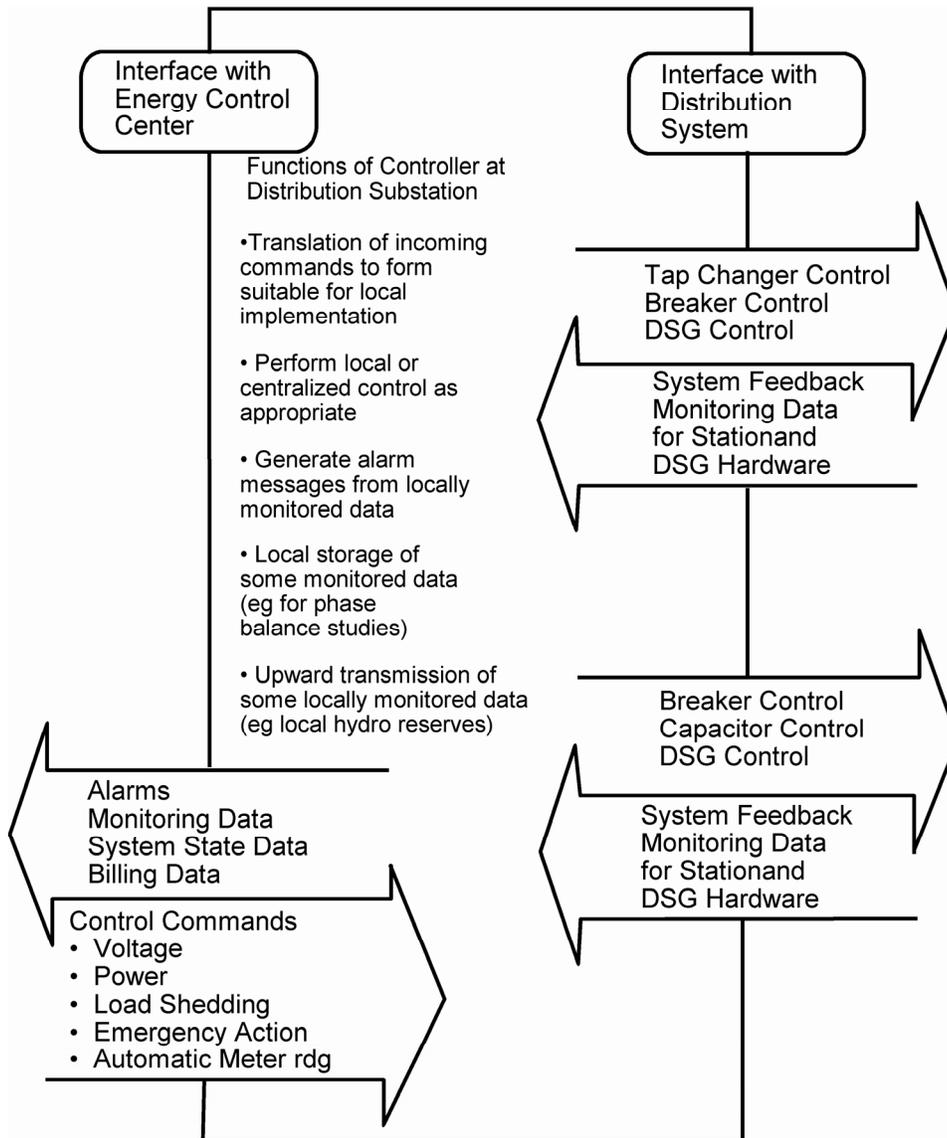


Figure 2-11. Functions and interfaces of distribution automation node at distribution substation

The role of the intermediate nodes in this arrangement is also crucial, and will be explored in our future work.

3. FIBER OPTIC SENSORS FOR DISTRIBUTION AUTOMATION

3.1. Introduction

We intend to demonstrate that fiber optics can be successfully and economically applied to the problems of distribution automation within the next few years. The technical feasibility of a fiber-based communication system was shown in Section 2. The economics are discussed in Section 4. In Section 3, we discuss the applicability of fiber optics to sensing for distribution automation.

Historically, the high voltages and currents in the power system have been isolated from the operator or the meter reader by means of potential transformers (PTs) and current transformers (CTs). The technology has been around since the turn of the century. Today, transformers of sufficient accuracy for protective relaying and for billing are available from a wide variety of manufacturers.

The instrument transformer furnished not only information about the parameter being measured, it also furnished energy to operate the relays that tripped the circuit breakers, and to drive the billing meters. With the recent advent of inexpensive fiber optic cables, several manufacturers are now building optical replacements for some measurement devices, particularly high-voltage current transformers. These new devices will not be capable of supplying the energy to operate conventional relays or meters. In the world of distribution automation this is no disadvantage. An automated distribution system will require hundreds – perhaps thousands – of measurements, designed to furnish information to a computer, rather than a handful of measurements comprising a self-contained protection scheme. In a distribution automation scheme, the operator's role is secondary to the part played by the computer. The problem to be solved by any modern power system control scheme is that of getting information about the power system into a computer. The computer can then initiate whatever control actions are required.

3.1.1. Fiber Sensors: Background

Over the last few years, optical fibers have seen increasing use in the communications industry. Their low cost and high bandwidth mean that they can be used for telephone trunk lines more economically than any other medium, including microwaves, metallic conductors and satellite links. Fibers have some properties which have made them of interest to electric power utilities. They are electrical insulators, immune to electromagnetic interference, and may be used in a number of harsh environments.

They are also small enough and robust enough to be used inside an electrical power conductor that is energized at thousands of volts, and that may be carrying thousands of amps. Some utilities have used optical fibers in their high-voltage transmission systems for communications between the ends of a transmission line. There are some parallels between telephone trunk

applications and transmission system applications. Nevertheless, our application is in the low-voltage part of the power system.

At the point at which the fiber is to be brought to ground potential, it is necessary to protect it from the ravages of the climate in such a way that its electrical integrity is not compromised. At least two U.S. manufacturers have solved this problem with a relatively inexpensive fiberglass and polymer insulator. The insulator spans the ground-to-line potential and affords the optical fiber the necessary environmental and mechanical protection. This greatly facilitates the high-voltage system communication applications of fiber optics.

It has seemed to many workers a natural extension of this work to use optical sensors to measure the various electrical and physical parameters of the transmission line, and bring this information to ground by means of these inexpensive insulators. There are a number of optical effects that can be used for measuring transmission line parameters. Some of them employ the fiber itself as a sensing element and others employ "witness crystals." It is probably fair to say that no two investigators have favored the same approach. Some manufacturers, and a few utilities, have been working on the problem of optical measurements over the last few years and have reported some success.

At the time that this is written (late 1988) no optical system is routinely employed in an American utility for measurement purposes. One or two systems are available from a small number of manufacturers, but rather more on a trial basis than on a routine sales basis. The cost of these systems seems relatively high, and while their performance is in many respects equal to, it is apparently not better than, the performance of the equipment it is intended to replace. Needless to say, the customers have not been beating down the door of the manufacturers of this equipment.

The component that has been chosen to be developed first by most manufacturers is the current transformer (CT) for high-voltage (HV) systems. There are a number of good reasons that this should be the first equipment developed, and a number of companies have been working on optical HV CTs. It is worthwhile before proceeding to explore why this particular component has received so much attention, because there are also some good reasons why these devices have not been widely accepted. In fact, while so much effort is taking place in the area of high-voltage CTs that this application might be called the "conventional wisdom," it is a thesis of this report that the HV CT is an inappropriate and unlikely way for fiber optic sensors to gain acceptance. This must be explained. It is therefore necessary to examine the pros and cons of the issue closely.

3.1.2. Optical Current Transformers

Conventional current transformers for high-voltage systems can be quite accurate ($\pm 0.1\%$) over a wide range of temperatures, but they can be very expensive. Given that the problem of bringing information from a high-voltage conductor to ground potential has already been solved inexpensively, it seems obvious that if this problem can be separated from the question of

actually making the measurement, a considerable economic advantage should result. After all, current transformers are quite inexpensive devices at low voltages. It is the necessity to insulate the output circuit from the high-voltage primary winding that increases the cost of high-voltage CTs.

There are two principal approaches to implementing an optical CT. First, the measurement of current can be done optically. Usually this involves the use of an optical material that changes the state of polarization of a beam of light in response to a magnetic field. A number of companies have been investigating this approach to current measurement, and their solutions differ principally in the optical materials used and in the means that they employ to compensate for their temperature effects. (Most magneto-optic materials are very temperature sensitive.)

The second approach to the optical CT is to use an electronic measurement to obtain a replica of the current in the high-voltage line. Data representing the current are then encoded onto an optical link. This approach is inherently capable of greater accuracy for a given complexity than the all-optical methods because it can use a conventional CT as the transducer. The principal disadvantage of this approach is that the measured data must be encoded in optical form, and this typically involves electronics. The electronics, in turn, requires electrical power.

In the United States, at least two manufacturers have recently disclosed that they have been developing an optical current transformer, and several years ago, JPL wrote a proposal for exactly such a device. In Europe, at least one manufacturer (ABB) has such a device ready for the market, and another (Schlumberger) has demonstrated prototypes. The first two of these optical current transformers (those from Square-D and Westinghouse) use an optical means for measuring the current. While this would seem to be fairly straightforward, it has not been a simple matter to achieve the required accuracy over the required temperature range. Because of the need to correct for many temperature effects, these optical current transformers are not simple devices.

The second two of the four current transformers (that proposed by JPL and that developed by ABB) are not truly optical current transformers. Each uses an uninsulated conventional current transformer, and encodes the data from it into optical form for transmission to the ground. At the ground, the signal representing the primary current is reconstructed. Performance equal to that of an ordinary current transformer should be easily possible.

Nevertheless, it is becoming apparent that the utility industry will not readily use such devices in the transmission system. There are many impediments to their adoption, but not all of them are applicable to the distribution system. This should make the distribution system attractive to manufacturers who want to introduce a line of optical instruments for power systems. Table 3-1 contrasts some attitudes regarding the transmission system and the distribution system.

While we do not endorse the utilities' apparent reluctance to embrace optical CT technology, we do wonder whether it was appropriate for manufacturers to design and produce an optical current transformer as a replacement for a conventional one. While the concept seems simple, the implementation is not. The modern high-voltage current transformer did not spring full-grown

from the R&D laboratory ready to take its place on the latest 765-kV line. It was developed over many years, from designs that had been successful at lower voltages. Comparing the transmission system and the distribution system in terms of suitability for the introduction of a new kind of current transformer, we believe that the balance is tipped in favor of the distribution system.

Table 3-1. Attitudes toward transmission and distribution systems

Transmission System	Distribution System
<p>Conservatism in the transmission system makes it unlikely that an "unproven" optical current transformer with electronic output will be accepted in the utility industry. After all, the consequences of poor information could be far-reaching.</p> <p>The optical CT, with its inherently low-power transmission medium (most fibers are carrying only microwatts) is profoundly unsuited to the application of meeting existing high-energy (5-A or 120-V) standards.</p> <p>The industry's experience with electronic relaying has left a bad taste in the mouth of many utility relaying engineers, who would equate electronic and optical relaying, and actively oppose the adoption of optical CTs.</p> <p>The accuracy demanded of a high-voltage CT can only be met with a complicated optical device which incorporates many means of compensating for the various temperature effects. The hardware is complicated, and scarcely competitive with its conventional counterpart.</p> <p>There are no standards for interfacing optical current transformers. The application of each individual optical CT into a high-voltage system would therefore require a considerable amount of engineering work on the part of the customer.</p> <p>As a replacement for an existing device, the optical CT has to offer a price or performance advantage over the device it replaces. This has not been possible, since the cost of development has been high, and the sales volume is expected to be modest.</p>	<p>Distribution engineers are becoming more daring in their application of new technology. Further, the distribution system is operated radially, so that the consequences of communication or control failure would not be catastrophic.</p> <p>There is no particular need to maintain compatibility with existing instrument transformer standards. Since there is no large commitment to existing methods, cost-saving new approaches can be considered.</p> <p>Distribution system relaying and protection has typically lagged behind that of the transmission system. Because of this, there has been no widespread bad experience with electronic relaying.</p> <p>The required accuracy depends on the application. Presumably the instrumentation will not be used for billing purposes. Measurements that are less than perfectly accurate may be acceptable because even imperfect data are sometimes better than none.</p> <p>There are presently no off-the-shelf distribution automation systems. Manufacturers can develop interchangeable, interconnectable parts. Setting their own standards, and using a "cook book" approach to implementation, they can obviate the need for system engineering on the part of the utility.</p> <p>A utility would view optical sensors as providing new information rather than as replacements. The sales volume can be expected to be enormous, so development costs can be spread over a large number of units</p>

It seems to us that optical devices are more likely to succeed in the distribution system. That part of the utility system is ready to examine a non-conservative approach because something better than the status quo is needed.

3.2. Criteria for Distribution System Sensors

To be commercially successful in the distribution system, as opposed to the transmission system, a sensor must meet a rather different set of criteria. The most important requirement is that the sensor be inexpensive, both to purchase and to install (preferably using live-line techniques). This means that it must be compatible with other distribution system equipment, and other distribution automation hardware and software. Of lesser importance is the accuracy, which need only be moderate (a few percent in many applications), and reliability (which can be lower than for transmission lines since maintenance of a distribution circuit is easier).

Since distribution systems are usually energized at relatively low voltages, 12 kV being typical in the U.S., the design of the insulation system should not pose a problem. At this level, voltage grading inside insulators is a simple matter, and external corona rings are not needed. Provided there is an insulation system to keep the cable clean, fiber optic cables can easily be made to operate with longitudinal voltage stresses. Getting light in and out of a line-mounted sensor should be easy.

Since most distribution circuits are constructed on wood poles, sensors that could be installed on existing lines must be small and light. Optical sensors could fit the bill; since they do not use steel, they are likely to be lighter than conventional instruments.

In general, one may expect passive sensors to be preferred, that is to say, devices that do not require batteries or line power for their operation. This is not a hard and fast rule, however; optically powered electronics or systems with internal energy storage for some hours of operation may be perfectly acceptable.

There is opportunity for innovation. The large number of sensors required to instrument a distribution line means that very little money can be spent on each device. Whereas a utility may spend tens of thousands of dollars for a set of high-voltage CTs mounted on their own steel pedestal and concrete foundation, they would prefer to spend only tens of dollars to measure the current in a distribution circuit. The cost of additional foundation work would be prohibitive. This requirement of very low cost should foster competition and innovation. Can less expensive materials be used? (We describe a plastic-cored iron-free current transformer below; others are investigating the electro-optic properties of low-cost materials such as Plexiglas, which could make an inexpensive 12-kV-class voltmeter.)

During 1988, our contribution to the measurement problem in distribution systems has been on three fronts: an optically-powered low-cost data link that could be used to energize a line mounted electronic measurement and return the data to ground; an optically powered integrator

and a linear coupler current transformer that can be used with the link; and a better understanding of the optics of the reflection of guided light from a variety of surfaces. We begin our description with the optically powered link.

3.3. Optically Powered Data Link for Power System Applications

3.3.1. Introduction

The use of optically-supplied energy as the sole source of power is well known in the communication satellite industry. At distances from the sun up to about the orbit of the Earth, the intensity of solar radiation in space is such that a reasonably-sized photovoltaic array can power a significant electrical load. Our application is more down-to-earth, but has the same general principle: optical power can be used to furnish energy to a location that is otherwise rather inaccessible.

In a power system application, optical powering allows the instrumentation designer to create a sensor that has the advantages of conventional electronics, while having the external attributes of being optical. The only connections to the device are optical fibers, which can easily be contained inside a composite insulator, so the sensor can be operated at line potential. There is no need for an auxiliary power supply, or for the complex temperature compensation sometimes needed with optical measurements.

During 1988, we developed a practical link that transmits optical power to a remote transducer, and data back. Sufficient spare power is available to energize an electronic measurement system.

The prototype link has moderate bandwidth (1 kHz), accuracy (1%), and dynamic range (>60 dB). While these are analog specifications, the link uses a frequency-modulated optical pulse train to retain noise immunity and insensitivity to changes in the fiber loss characteristics. The approach could be used with any of the usual electrical or electronic measurements: current transformers, strain gauges, thermocouples, etc. As an example, we present results showing current measurement by means of a linear coupler.

3.3.2. Review of Optical Powering

The earliest description of a fiber- (rather than solar-) optically powered device for terrestrial use seems to have been for telephones: a system was described by DeLoach, Miller and Kaufman at Bell Labs in 1978. In 1981, an approach to optically powering an implant in a human body was described by DeLoach and Gordon. In 1984, a temperature measurement system was described by Ohte, Akiyama and Ohno; and McGlade and Jones described an optically-powered force sensor. Perhaps because the amount of electrical energy available at the load was small, this method of energizing electronics did not generate widespread commercial interest. Nevertheless,

it would seem perfectly suited to power system applications where the advantages of electrical isolation and immunity to noise are important.

There have been other, more recent, examples of optical powering of electronic systems. A computer-controlled sensor network was described by Hall in 1986. In 1987, a pressure transducer was described by Schweizer, Neveux and Ostowsky. However, there seem to have been no power-system applications until a 1988 paper by Adolfsson, Einvall, Lindberg, Samuelsson, Ahlgren and Edlund that described an optical CT using this principle. Their device operates at a very low power level, through the use of custom integrated circuits.

Over the last few years, our group has developed a number of electric- and magnetic-field sensors that use optical power to supply the electronics (Kirkham, Johnston, Jackson, and Sheu, 1987; Kirkham and Johnston, 1988). In these instruments, the driving factor for the use of optical power (rather than batteries) was size. A considerable amount of effort was devoted to the development in our laboratory of a small photodiode array for the purpose of energizing our field-meter probes. The arrays were fabricated in gallium arsenide, and consisted of four strings of diodes that could be interconnected in any arbitrary fashion, so as to provide a very flexible power supply. The array was approximately 3 mm × 3 mm and had a peak power output of over 3 mW when suitably illuminated. The data link described in this report derives from our earlier work. However, all the components used in the present example are commercially available, including the photodiode array.

Recent developments, particularly in laser technology, have meant that the application of optical power in this way is now a reasonable economic alternative for the designers of power system instrumentation. The principal limitation in optically powering a piece of electronic equipment is the low level of power available in electrical form. However, as is shown in this report, useful functions can be implemented with the amount of power available from modern laser diodes.

3.3.3. System Design

The generic measurement system, using an optically powered data link, can be divided into three parts, as shown in Figure 3-1:

1. The measurement of the primary quantity (in the example of Figure 3-1, the current) and the processing of the resulting signal,
2. The data link which transmits the signal to ground potential and reconstructs a replica of the measured quantity,
3. The power supply which energizes the remote electronics.

3.3.4. Measurement and Signal Processing

The measuring instrument itself can be conventional, and any normal electronic transducer with a small enough power requirement could be used. For example, for current measurement a CT

could be used, provided with a suitable burden. This is the approach taken by Adolffson *et al.* We decided instead to demonstrate current measurement with a linear coupler, which requires a high-impedance buffer and an integrator to couple it to the data link. (Details of the functioning of the linear coupler are given in Appendix A.)

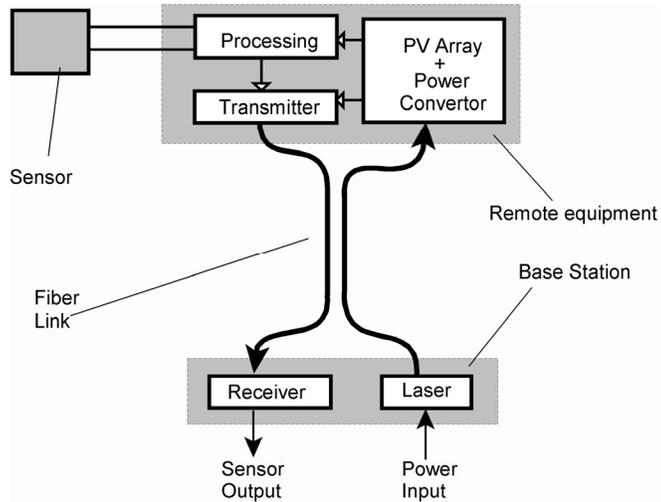


Figure 3-1. Generic optically powered measurement system

3.3.5. FM Link

The FM data link was designed to telemeter an analog signal and was to be flat from dc up to about 1 kHz. This seemed like a reasonable general-purpose goal, and one that could be achieved within the limitations of optical power. The link is shown in Figure 3-2. It consists of a voltage-controlled oscillator (VCO) and an optical pulse generator, both located in the transducer head, the optical fiber itself, and a receiver that reconstructs a replica of the original signal.

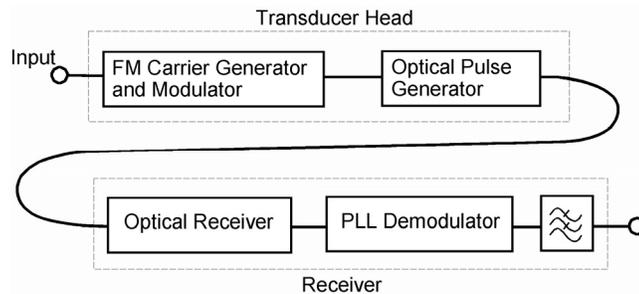


Figure 3-2. Optical FM link

The data link can handle an input on the order of 1/2 V, and has an input impedance of $\approx 10 \text{ M}\Omega$. These values were set by the FM modulator used to transmit the signal to ground. The system uses a CMOS phase-locked loop (PLL) chip to frequency modulate a carrier at 10 kHz. This

device is simple to use, low power, and can be adapted to generate very short pulses to drive the optical transmitter, so as to hold down the total power consumption of the remote electronics.

3.3.5.1. Transducer Head

Figure 3-3 shows the circuit of the remote electronics. In our application, the linear coupler is buffered by a high-impedance unity-gain stage, so that it operates essentially open circuit. This stage drives an integrator configured to have a corner frequency just below 60 Hz, so that the system transmits a replica of the current rather than the derivative, accurate from power frequency up to several harmonics. Details of these circuits are not shown in Figure 3-3, since the arrangement is quite standard.

The FM modulator chip (CD4046) contains a complete PLL system. The VCO section is used to generate the FM carrier. The oscillator is temperature dependent to an extent that depends on the value of the external timing resistor R_1 . To minimize power consumption, R_1 should be as large as practicable. This results in the VCO frequency being quite temperature dependent. To improve link performance, the center frequency of the VCO must be temperature compensated.

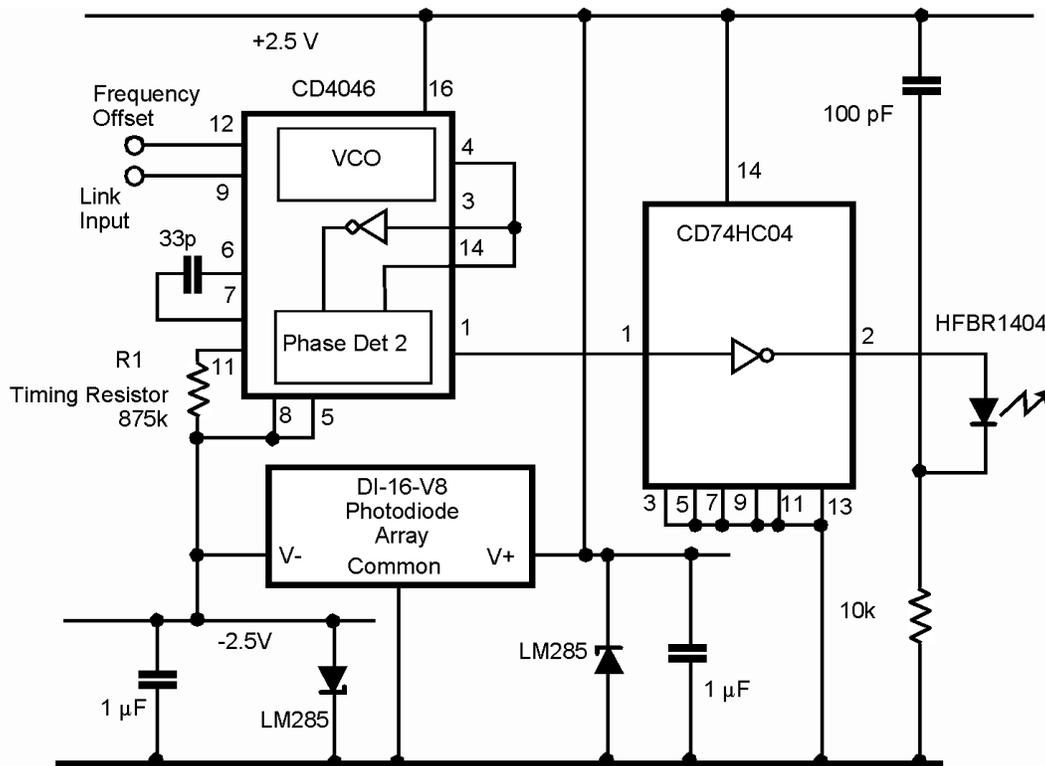


Figure 3-3. Transducer head electronics

There are two constraints on the temperature compensation method used. It must not affect the sensitivity of the VCO, and it must have very low current consumption. The method we used takes advantage of a frequency offset capability of the CD4046, as shown in Figure 3-4. Transistor Q_2 and diodes D_1 to D_3 form a current sink whose current is set by the value of R_2 and the forward volt-drops of the diodes and the base-emitter junction of the transistor. These volt-drops are temperature dependent (about $-2.1 \text{ mV}/^\circ\text{C}$ each), so the current decreases with temperature. This is in the right direction to compensate the CD4046 oscillator, but there is a large component of the current that is not temperature dependent because of the $\approx 0.65\text{-V}$ drop of a forward-biased junction. This component of current is removed by transistor Q_3 , which is operated as a current source. Diode D_4 compensates for the temperature-induced variations in the V_{BE} of Q_3 , so that the programmed source current is almost independent of temperature.

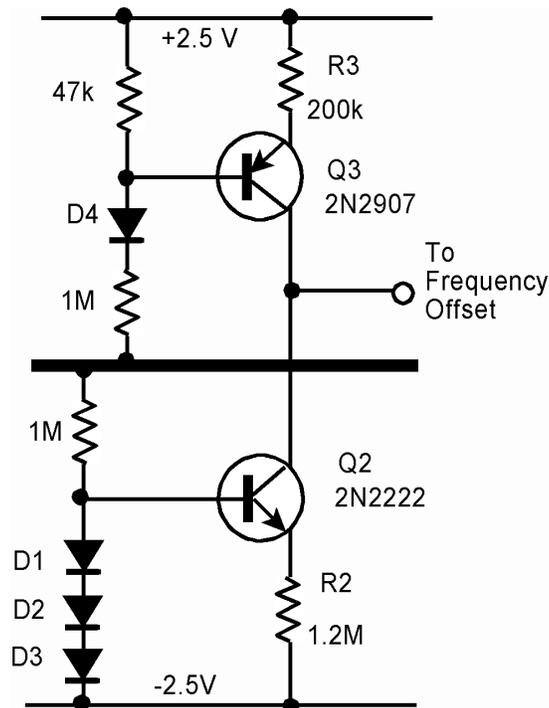


Figure 3-4. Temperature compensation of VCO

The compensation circuit is connected to the frequency offset pin of the VCO. Any difference between the temperature-dependent source and the constant sink currents must be made up by a current source inside the CD4046 circuit. It adds algebraically to the timing resistor current. The use of current compensation (rather than resistive) means that the offset is independent of the voltage on the VCO input, ie, it does not change the sensitivity of the VCO.

The otherwise unused gates of the phase detector are used to generate short pulses ($\approx 150 \text{ ns}$) from the VCO square wave, to minimize power consumption. These pulses are used to drive the LED, via a circuit reminiscent of a photographic flash, designed to minimize power supply current. A high-speed CMOS inverter (74HC04) charges a small capacitor (100 pF in Figure 3-3)

to the power supply voltage through a 10-k Ω current-limiting resistor. When the VCO pulse drives the output of the inverter high, the LED discharges the capacitor. The current is large enough to generate the required optical power. Since the current does not come directly from the power supply, regulation is good. The average current is lower than that obtained by a conventional LED driver design.

Any ordinary LED may be used to generate the optical pulses, but note that a better power margin in the link is obtained with a more efficient LED. Our prototypes used the HFBR-1404, a plastic-encapsulated LED manufactured with an integral fiber connector.

3.3.5.2. Receiver

The purpose of the receiver is to reconstruct the signal transmitted by the remote electronics. First, the optical pulse train is converted to electrical form. While these narrow pulses can be handled by the PLL demodulator, noise considerations in the demodulated output require a square wave to be used at the phase detector. Consequently, a flip-flop is used to generate a square-wave input to the PLL, which runs at 5 kHz, half the link frequency.

The frequency response of the modulator in the remote electronics is essentially flat, so the frequency response of the link is controlled by the response of the PLL in the receiver and by a filter used to reduce noise in the output. Gardner (1966) shows how the loop filter affects the overall loop response. The natural frequency ω_n and the damping factor ζ for a loop with a passive lag-lead filter can be specified separately. For a loop with $\zeta \geq 5$, the response is relatively flat until several times the natural frequency of the loop.

For our purposes, we required a frequency response essentially flat out to 1 kHz. This led to the choice of a natural frequency for the loop of 100 Hz, and a damping factor of 7. Details can be found in a report dealing with an earlier application of this link (Kirkham and Johnston, 1988). Because the loop filter contains a zero at a frequency not greatly above that of its dominant pole, the output of the phase-locked loop contains a considerable amount of energy at twice the VCO frequency. Indeed, the output of the loop filter is an almost rectangular wave whose mark/space ratio varies as a function of the modulation in the loop.

In order to recover the modulating signal from this, it is necessary to apply further filtering. Consequently, the signal is applied first to a low-pass filter. The filtering must be done first (before any linear amplification used to set the overall scale factor) in order to suppress any remnants of the phase detector square-wave output.

3.3.5.3. Dynamic Range

The maximum signal that can be transmitted is limited by saturation. The link was designed so that the probe saturates before the receiver, so that for ordinary conditions the amount of

modulation on the optical link is maximized. This maximizes the dynamic range, if (as we expect) noise is introduced in the link. Signal processing gain ahead of the link should be maximized, concomitant with this principle.

At the other extreme, the noise level in the system sets the lowest signal that can be measured. A wideband signal ordinarily contains more noise than a narrowband signal. Since the bandwidth of the link is fixed, the use of low-noise components, particularly in the early signal-handling stages, is the only option to minimize noise.

3.3.6. Optical Power Supply

The optical power supply consists of four sections:

1. The laser which generates the optical energy,
2. The fiber which transmits that energy to the remote electronics,
3. The converter which produces electrical energy from the optical input,
4. The regulators used to stabilize the load voltage.

3.3.6.1. Laser

We chose to design our power supply around a multistriple laser with a fiber pigtail attached. Lasers of this kind are available with power outputs of over 100 mW (optical) and are quite reliable and economically priced.

It should be noted that if the kind of link described here were to be used in a critical situation, the remote electronics could be powered by two lasers simultaneously, by combining their outputs in an optical coupler. The lasers would be chosen so that either laser alone would be enough to power the system. By monitoring the output of the laser from its back facet, failure of either laser could then be used to generate a "maintenance alarm."

3.3.6.2. Fiber

The laser couples the optical power to the remote electronics by means of an optical fiber. Multimode 100 mm (or larger) fiber with $NA \geq 0.3$ is used. Bearing in mind that the electronics returns an optical signal to ground also using fiber optics, the fiber link can be implemented by means of two separate fibers (one for power, one for data), or by only one fiber (to carry power in one direction and data in the other). If only one fiber is used, the designer must also separate the optical energy going in the two different directions. Inevitably, imperfections in directional couplers and backscatter in the fiber will create a background in the signal channel.

Ohte and his co-workers chose to use the single-fiber method, with dichroic mirrors to separate the different wavelengths used for data and power. Most optically powered systems have been designed instead to use two fibers. A tradeoff exists between the cost of a second fiber and connectors, and the cost of the extra complexity required by the bidirectional approach. We feel that the balance is tilted toward using two fibers.

The energy from the optical-power fiber was coupled directly onto the photovoltaic converter array. Since the dimensions of the array were much larger than the fiber core, an airspace was introduced between the end of the fiber and the photocell array. The gap was adjusted to allow the emerging beam to spread, to match the size of the array as well as possible. Such an arrangement proved simple and effective, although somewhat better matching could be obtained with a suitably designed tapered-horn beam expander.

3.3.6.3. Photodiode Array

A commercially available diode array (Dionics DI-16 V8) was incorporated in the remote electronics to convert the optical input back into electrical form for powering the measurement circuit. In general, after the laser, the limiting factor on the power available for use in the remote electronics is the photodiode array. There are four reasons that the arrangement we used limits the available power.

First, there is an inherent shape mismatch of approximately 30%. The light emerging from the end of a conventional multimode fiber with round cross-section describes a cone of circular section, whereas the diode array used was square. Further, there is a nonuniformity of the energy density across the output area, and this causes a drop in the array output below the theoretical maximum per cell.

Second, there is no anti-reflective coating on the array or on the end of the fiber. Such coatings, tuned to the laser wavelength used, might be equivalent to a 5% increase in the input power.

Third, gallium arsenide would be more efficient at the wavelength used, in terms of better matching the bandgap of the laser material.

Finally, gallium arsenide has a semi-insulating state that can be used as a non-conducting substrate for the epitaxial growth of the diodes. Therefore the diodes can be fabricated very close together, and little light is lost illuminating the region between them. Silicon has no corresponding state, and series-connected diodes have to be made using dielectric insulation, which requires a slightly larger gap between the diodes.

Having said this, however, the fact remains that the technology of processing gallium arsenide is not as well developed as that for silicon. Our group has put considerable effort into the development of suitable GaAs photocells over the last few years, and produced only a small number of successful prototypes. The availability of a commercial diode array far outweighs the small loss in efficiency that the use of silicon entails. The design of the Dionics array is

remarkably similar to the GaAs array we designed independently (and later), with 16 diodes in a square configuration. A sample array, mounted on a ceramic substrate, is shown in Figure 3-5. We used the bare chip array shown because we were interested in making hybrid circuits. The array is one of a small family of photodiode arrays that can be obtained in a variety of packages.

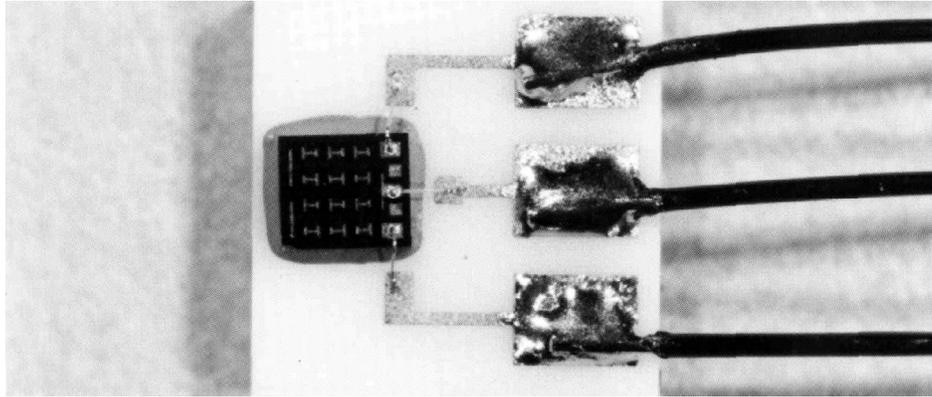


Figure 3-5. Diode array (Dionics DI-16 V8)
mounted on ceramic substrate

3.3.6.4. Regulators

Our earlier work with supplying optical power to electronic systems by means of fiber optics highlighted the need to stabilize the voltage generated by the PV cells. Even the small fluctuation in optical input power from flexing the fiber caused a measurable change in the carrier frequency in some of the FM oscillators used for data encoding. Ordinary zener diodes are inadequate at the low voltage used. A better solution was found to be the use of a band-gap reference diode as if it were a zener. The internal resistance of the PV array is enough to prevent damage to the reference diode. Suitable diodes are available with voltages of 1.25 and 2.5 V.

3.3.7. Measured System Performance

3.3.7.1. Power Supply

The Dionics DI-16 V8 photodiode array was tested using a controllable load, and its I-V curve was obtained. This is shown below in Figure 3-6. The data shown in Figure 3-6 were obtained by illuminating the array by means of a fat fiber (400 μ m core) located approximately 5 mm from

the array, and energized by means of a 30-mW laser with $\lambda = 810$ nm. With the fiber at this distance from the array, which is ≈ 900 mm across, all 16 diodes are illuminated.

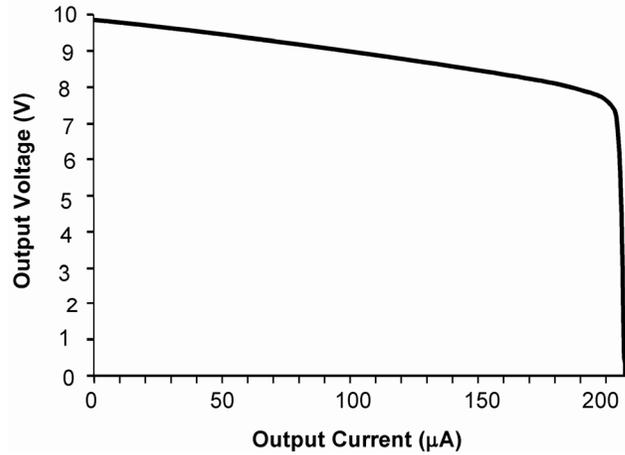


Figure 3-6. Diode array characteristics

Peak electrical power is ≈ 1.5 mW. However, a somewhat smaller amount than this is actually available for use in the electronics because the voltage regulators reduce the supply to 5 V.

With 30 mW optical input, the photodiode array produced up to 200 mA output. The current consumption (at 5 V) of the various parts of the transducer head is shown in Table 3-2.

Table 3-2. Current consumptions

Component	Current (µA)
VCO	26
Temperature Compensation	1
LED driver	26 (17 mA peak)

Low-power operational amplifiers are available that can function with as little as 40 mA each. Thus, without increasing the optical power input, three such amplifiers could be supplied.

The output voltage of a PV cell typically falls with increasing temperature. The array used here is no exception. The open-circuit voltage of the array was found to decrease at about 0.033 V/°C. This indicates that the output is enough to drive our electronics at temperatures beyond the 40 °C we considered reasonable.

The LED current can easily be adjusted to control the optical power output. With the values shown in Figure 3-3, the average LED current is 26 mA, the same as the VCO. Peak current is 17 mA. The optical power output is ≈ 80 mW, measured at the end of a 400-mm fiber. With the HP2202 optical receiver, used in our prototype, there is an optical power margin of 11 dB.

3.3.8. Data Link Performance

3.3.8.1. Link Frequency Response

The measured link frequency response is shown in Figure 3-7. The link response is flat (within 1 dB) from dc to ≈ 1000 Hz. Above this, the response is attenuated. Nevertheless, the output is only 0.5 dB down at 1 kHz, compared to the response at 100 Hz.

These results are a combination of the response of the receiver PLL and the low-pass filter. Careful trimming of the filter components could result in an even better response.

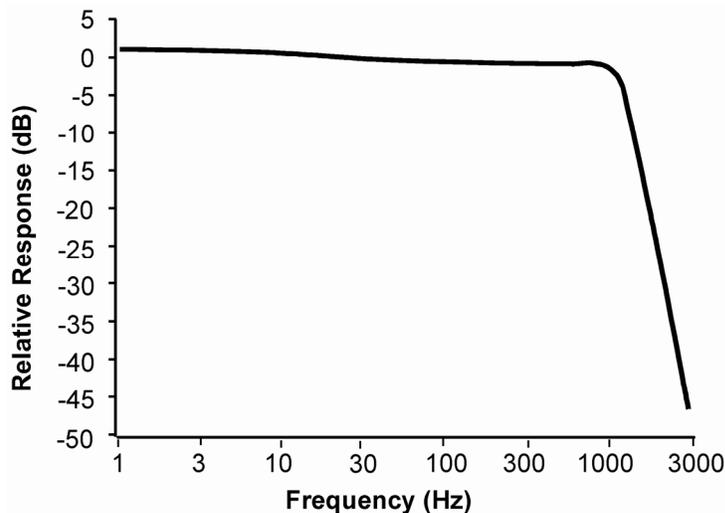


Figure 3-7. Link frequency response (0 dB = 100 Hz)

3.3.8.2. Dynamic Range

The dynamic range of the link is shown in Figure 3-8, which compares the experimentally determined error as a function of applied voltage. The graph shows errors of less than 1% for voltages between 500 μ V and 700 mV. The error is somewhat dependent on frequency, indicating some nonlinearity in the link, probably in the matching of the oscillator

characteristics. Above 700 mV, the error increases very rapidly. This is the effect of clipping in the remote electronics. Below 500 μV , the error increases gradually, as noise makes an increasingly large contribution to the reading.

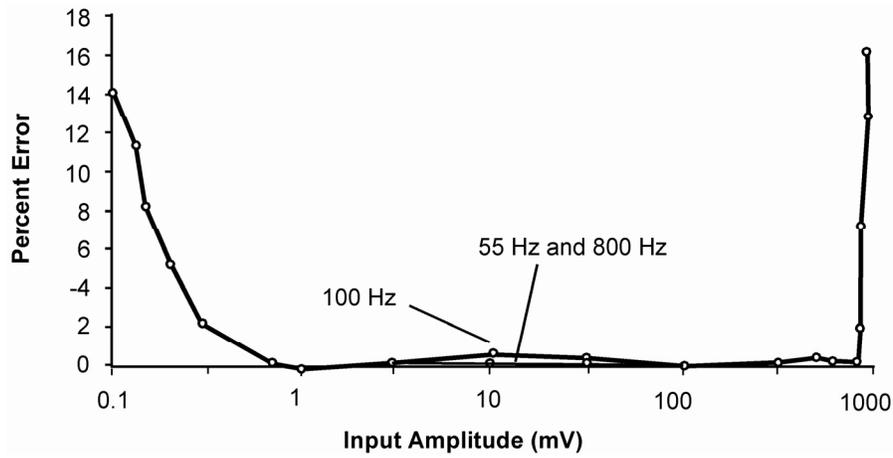


Figure 3-8. Dynamic range of link at 55, 100 and 800 Hz

The dynamic range of the link is better than three orders of magnitude, from $<700 \mu\text{V}$ to $>700 \text{ mV}$. Output waveforms for 60-Hz sine-wave inputs at amplitudes near the extremes of the range are shown in Figure 3-9.

The noise from the link can clearly be seen in Figure 3-9(a) for the 700- μV input. Even so, the noise is not contributing significantly to the measured signal level. Even smaller signals can be measured, but with increasing error, as shown in Figure 3-8. As far as large signals are concerned, note the small amount of distortion discernable in the 700-mV output, Figure 3-9(b). This source of error is not appreciable until the input reaches about 750 mV.

3.3.8.3. Stability

The prototype link was temperature tested. Without compensation, the temperature drift attributable to the CD4046 alone (as opposed to the other frequency determining components) was measured between -10°C and 30°C , and found to be a very constant $0.26\%/^\circ\text{C}$. We concluded that great care in temperature compensation would be required if dc level were not to produce a bias in the measurement. The current compensation of the VCO center frequency was effective in reducing the drift considerably. By adjusting the compensator static current (by changing the values of R_2 and R_3 in Figure 3-4), the drift was reduced below $0.005\%/^\circ\text{C}$, or $50 \text{ ppm}/^\circ\text{C}$. This is an acceptably low value for all but the most demanding applications. The current through the compensation circuit was 870 nA.

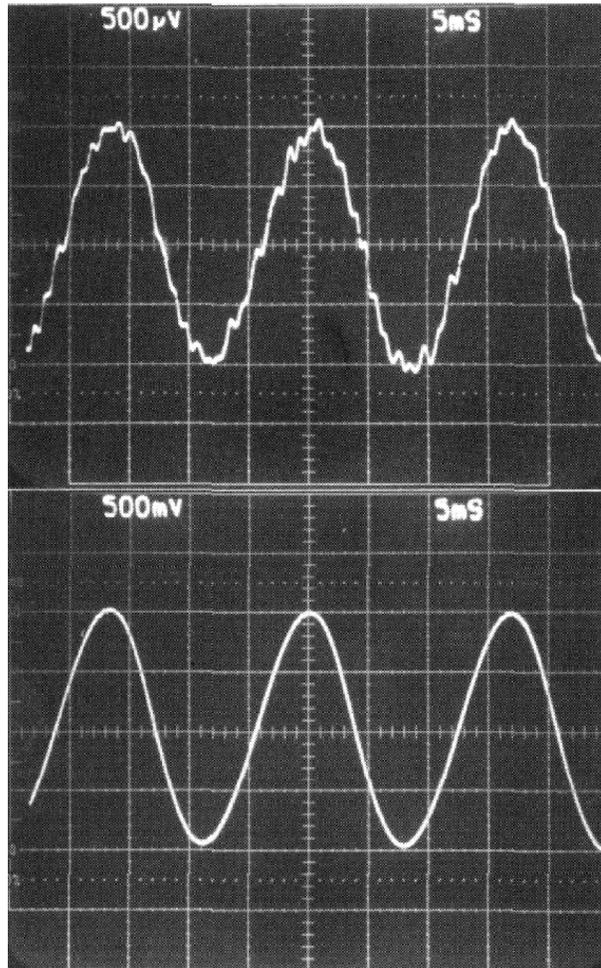


Figure 3-9(a)

$V_{in} = 700 \mu\text{V}$

Figure 3-9(b)

$V_{in} = 700 \text{ mV}$

Figure 3-9. Output waveforms at 700 mV and 700 mV input

3.3.9. Example Application of Link

3.3.9.1. The Current Measurement Problem

As transmission voltages increased into the EHV region, the cost of insulating current transformers increased. In addition, problems of insulation reliability have been encountered. In the hopes of avoiding these problems, considerable interest is being shown in the optical measurement of current. An optical sensor can be connected to line potential, and it is easy to insulate the output using an optical fiber.

A current measurement based on the use of a linear coupler, rather than a CT, has the advantage that the core of the toroid can be made of a very inexpensive insulating material. No particularly stringent magnetic properties are required. Because of this, the sensor can be made very inexpensively, provided the electronics associated with the encoding of the measurement can be energized satisfactorily. The optically powered data link described above is well suited to this application. Therefore, we used the current measurement problem to demonstrate the performance of the link.

3.3.9.2. Example of Current Measurement

Current measurements were made using a linear coupler with the optically-powered data link system. A device like the linear coupler was described by Rogowski in 1912¹, but it has not found wide application in power systems since that time. There are several reasons that the linear coupler is not commonly used in power system measurements. First, since the device is high impedance, it is somewhat susceptible to noise pickup. This is especially true if there is appreciable distance between the coupler and the electronics.

Second, to give a replica of the current (rather than its derivative), the linear coupler requires an integrator. This is an additional measure of complexity compared to a conventional CT.

Third, because of the high impedance of the device, a conventional relay cannot be driven by the low output of a linear coupler.

However, the linear coupler has advantages over a conventional CT. It is entirely linear because there is no magnetic material to saturate. In three-phase relaying applications where phase balance is required, this linearity may be more important than the derivative nature of the output.

By combining a linear coupler with an optically powered integrator and data link, the usual problems of the linear coupler are solved: by putting the integrator adjacent to the pickup coil, both the derivative problem and the problem of noise pickup are solved; by powering the system optically, it is made to seem passive; further, the output of the data link could be used to feed an electronic relay that would not need to be particularly high impedance.

For demonstration purposes, we used a linear coupler/integrator/link combination to measure the current in a simulated fault situation. The design goal for our prototype was to be able to simulate a 100-A CT. To ensure sufficient overdrive margin, the remote electronics was designed to saturate at a simulated 10 kA. There is a tradeoff between the number of turns in the coil and the gain of the first-stage amplifier.

¹ Physicists tend to call toroidal current-measurement coils "Rogowski coils", although the original was actually a flexible band 60 cm long, 2.5 cm wide and 1 mm thick, used to measure magnetic potential, ie, the line integral of the magnetic field between two (separate) points. Power engineers generally use the term "linear coupler" to describe an air-cored CT.

The minimum number of turns is set by the need for uniformity around the toroid, and by an increasing noise contribution from the first stage of the electronics if its gain has to be made too high. In our prototype, a single layer winding of 1046 turns was used, and we decided to operate the first stage of the remote electronics as a unity-gain buffer. The coil was wound on a plastic core of circular cross section, 0.95 cm in diameter. The toroid was 6.7 cm in diameter.

An inductive load (X/R ratio ≈ 10) was energized with maximum current offset, and the link output compared with the output of a current shunt. The results are shown in Figure 3-10.

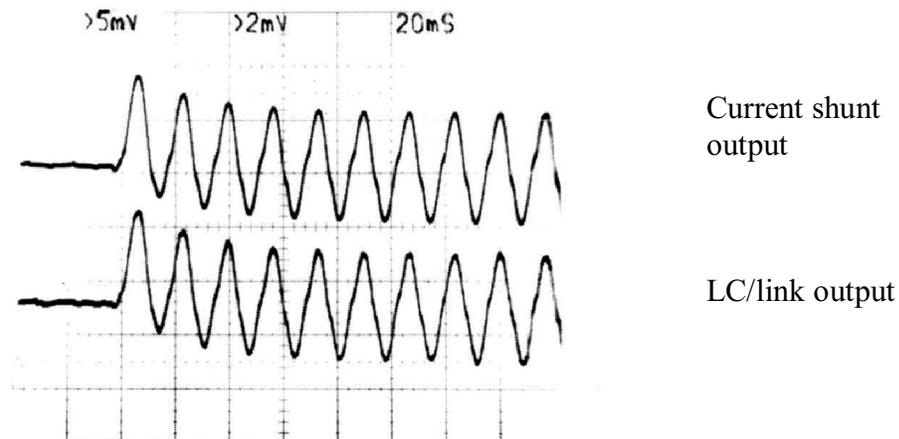


Figure 3-10. Link transient results

There is little difference between the current measured by the LC/link combination and by the shunt. There is slightly more noise on the link output prior to energization. Note, however, that the link is operating about a factor of 350 below its maximum output. The system overdrive margin (or headroom) is about 50 dB in this example.

3.3.10. Future Work

More than any other aspect of the link, the limited power at the transducer head constrains the design. While a successful link has been demonstrated, the usefulness of the approach would be enhanced by the availability of more power for the remote electronics. There are a number of ways that this could be accomplished.

A solid-state laser is perhaps the most efficient way to launch optical energy into a fiber. Efficiency was important in the portable applications that were the precursors of the present work. The use of multiple fibers in a square pattern is one way to improve the efficiency of converting the optical energy to electrical using the same kind of photodiode array. This approach is being studied.

We are presently performing experiments with add-on waveguides of square section and sufficient length to allow a reasonable amount of mode mixing from the circular fiber. If successful, this work should lead to an improvement on the order of 20-30% in the efficiency of the array. We intend to report on this work elsewhere.

Other ways to generate the electrical power for the electronics are being considered. While a GaAlAs photocell array would be most efficient, such a device seems not to be commercially available. Our own attempts to develop a suitable array have now been abandoned in favor of the Si array described here. There are still some alternatives. A single diode driven by a pulsed laser could be used with a transformer to increase the output voltage. A high-efficiency dc-dc converter, or doubler, used with a single circular GaAlAs diode might also give better overall performance than the array approach used here. However, the complexity of the system would be increased somewhat.

In a situation in which power is abundantly available, light sources other than lasers can provide large amounts of energy. Some of these, such as a high-intensity cesium source developed for firing optically triggered thyristors may have promise in the present application (Witting, 1983).

3.3.11. Concluding Remarks

The practicability of an optically powered data link has been demonstrated. The link has moderate bandwidth (1 kHz), accuracy (1%) and dynamic range (>60 dB), over a useful range of ambient temperatures.

The link uses commercially available components, including the photodiode array, which is fabricated using the dielectric isolation process in silicon.

Power transmission efficiency is presently low, at about 0.3% overall (electrical-to-electrical) and 5% optical-to-electrical. Ways to improve these figures are known, and are being investigated empirically. Some of this work may enable the use of even lower cost light sources, though we note that the cost of solid-state lasers is continuing to decrease.

It appears practical to design and build a range of instruments that use optical power. The performance of such instruments could be optimized for different applications, for example by trading off bandwidth for dynamic range.

CMOS technology is inherently low power. By using application-specific integrated circuit (ASIC) techniques, low-cost production methods could be employed. Such a step would make the optically powered instrument widely competitive.

3.4. Reflection of Guided Optical Waves

3.4.1. Introduction

Between 1984 and 1987, we developed a series of field meters for the DOE. The first one measured the electric field due to a direct current power line, without any reference to the ground. Then a sensor was built to measure the electric fields due to ac power lines. The most recent instrument measures the magnetic field due to ac power lines.

In 1987 the dc electric-field meter system was taken to a high-voltage laboratory operated by ASEA, in Sweden, to participate in tests that were being conducted on a high-voltage dc bushing. Generally, the instrument performed well. However, in an environment of rain and wind, some problems were experienced with the position fiber (Kirkham and Johnston, 1988).

3.4.2. Position Sensor

Figure 3-11 shows the inside of the dc field sensor. The position of the external field with respect to the sensor and the rate of rotation are sensed by a stationary fiber which picks up, by means of a reflective spot on the housing edge, light reflected once per revolution. In the figure, it is shown as the position pick-off. For the system to work, collimated light emerging from the fiber must strike the reflective spot normally, so that it reenters the fiber.

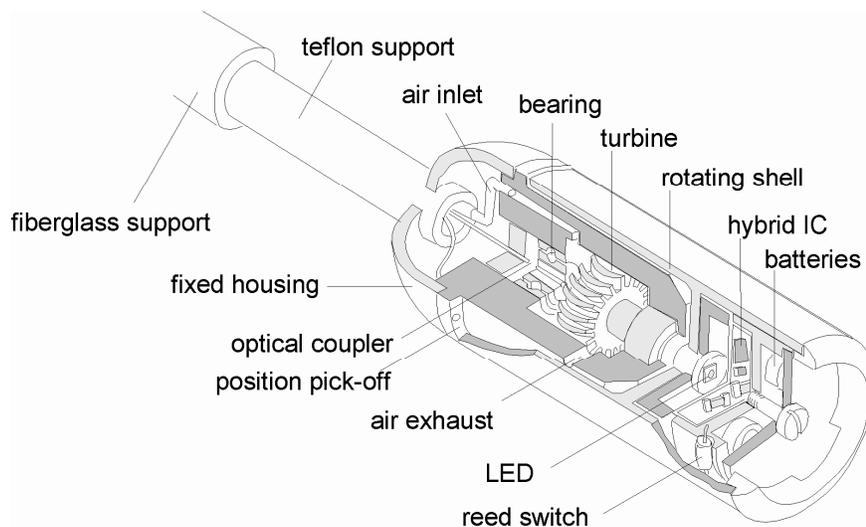


Figure 3-11. Cutaway view of dc field meter probe

3.4.3. Problems

There are several difficulties with this position sensor. First, the collimated light must strike the target normally in order to carry back a pulse. Failure to achieve proper alignment can cause unacceptable power loss in the pulse from the sensor. This places an alignment requirement on the spinning housing that is difficult to guarantee. Second, the position of the reflective spot and collimator lens on the edge of the housing made them vulnerable to moisture and foreign-object interference. The system is also expensive because it requires two costly optical components: a beam splitter and a collimator. In addition, losses are great enough to require a photodiode amplifier in the receiver to make the signal readable.

We sought to make a cheaper and more durable sensor. This would enable us to monitor and control rotation speed within acceptable range and also to automate speed control. There was a need to design a reflection system to ensure that a sufficient fraction of light impinging on the reflective spot returned to the collimator without careful adjustment, impossible with an ordinary mirror.

The problem of debris on the collimator lens is solved by burying the fiber deep within the housing. Moving the fiber and the reflective spot to the inside of the housing eliminates gross moisture and dust problems, but makes alignment of the collimator difficult. Figures 3-12 and 3-13 contrast the original and the modified position-pulse system, in which the optics are protected from the environment.

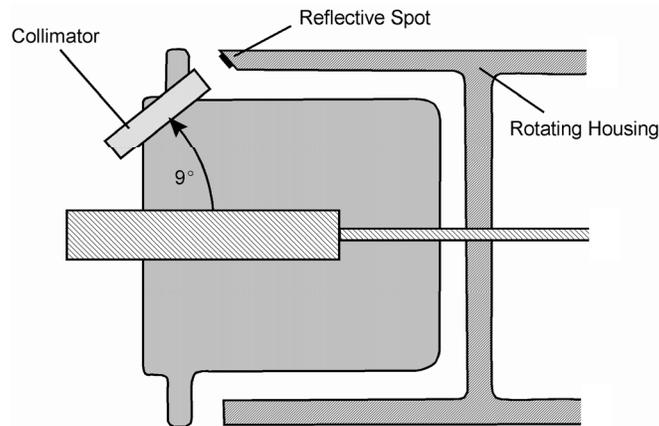


Figure 3-12. Original position-pulse system

Investigation of a fiber pair to replace the single fiber was also undertaken. It was hoped that a two-fiber system could be constructed at substantially less cost than the one-fiber setup, and with less stringent alignment requirements. Light from an LED could be launched down a fiber and allowed to scatter at the reflective surface. The reflected light could then be collected by another fiber, one with a larger numerical aperture which can recapture more of the scattered, reflected light. Figure 3-14 describes such a 2-fiber setup.

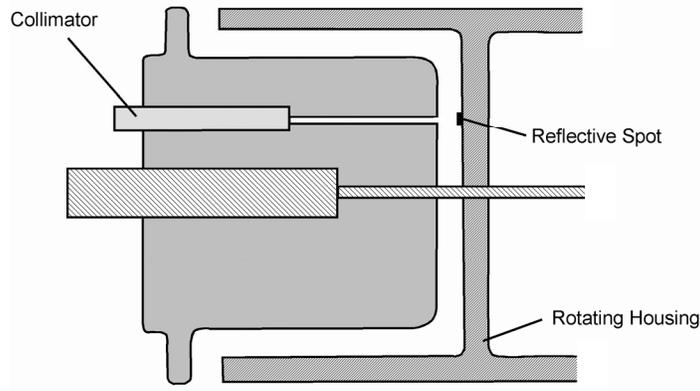


Figure 3-13. Modified position-pulse system

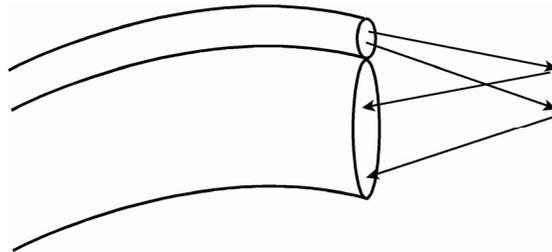


Figure 3-14. Two-fiber position-pulse arrangement

3.4.4. Other Applications

The subject of a position indicator is also interesting because of its distribution automation applications. A position sensor could be used as the optical analog of auxiliary contacts on a circuit breaker or a switch. A low-cost and reliable position indicator might be used to retrofit other distribution system hardware during the implementation of a distribution automation scheme. For example, some pole-top fuses have the feature that they swing out when they blow. Ordinarily, optical inspection of this condition is performed by a member of a line crew. A position indicator could automate the process.

3.4.5. Possible Solutions

To improve the performance of the dc electric-field meter and, in addition, provide an inexpensive and reliable position sensor for new devices, several steps were taken. First, an examination was undertaken of the reflective characteristics of a number of materials.

It was desired to study the coefficient of reflection as a function of angle to identify any materials significantly less sensitive to alignment than others. As the work proceeded, it became evident that the measurement of surface properties was not as simple as had been hoped. It was difficult to separate surface effects from the influence of the optics illuminating the surface and measuring reflected power.

Consider the arrangement shown in Figure 3-15. For the time being, let us consider only the effect of variations in the angles in the plane shown. A collimator is used to illuminate the surface being tested. If this is a perfect collimator, a small region of the surface is illuminated by light with some incident angle ϕ as shown. This light strikes the surface and is reflected and scattered.

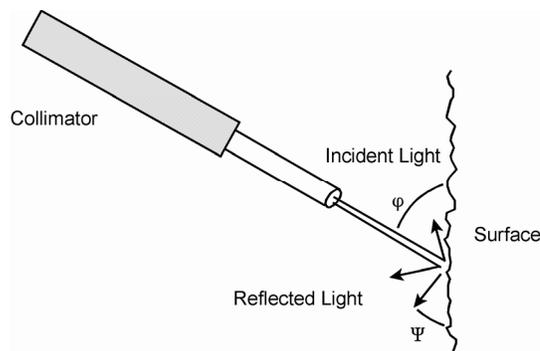


Figure 3-15. Illumination for surface reflectivity measurement

It seems reasonable to suppose that the power reflected from the illuminated region can be expressed in the form $P(\psi) = R(\psi, \phi)P_{in}$, where $P(\psi)$ is the power reflected as a function of the angle ψ , $R(\psi, \phi)$ is a reflection coefficient, a function of both the incident angle ϕ and the reflection angle ψ , and P_{in} is the input power level. The object is to measure the reflected power to obtain the reflection coefficient, $R(\psi, \phi)$.

The optical arrangement used to measure the reflected power is shown in Figure 3-16. It does not matter whether we use the same collimator to collect reflected light and illuminate the surface, or whether some other optical arrangement is used. In either case, the receiving optics will have associated with it some capture fraction that operates on the power at the receiving end. This fraction might be written in the form $C(\alpha, d)$, where α is the off-axis angle of the receiving arrangement, and d the distance from the surface. If the surface is a diffuse one, and the incoming light is collimated as shown, the power density at the receiver can be expected to fall off with distance from the surface.

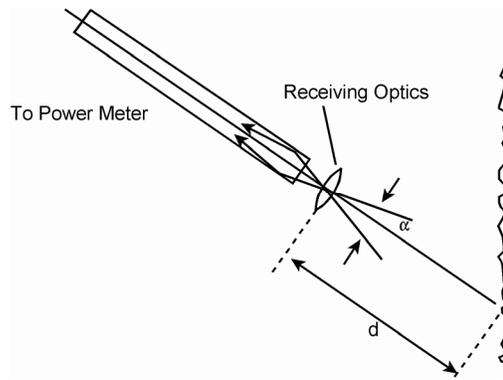


Figure 3-16. Receiver for reflectivity measurement

This shows that the power measured by a power meter behind the receiving optics will be a function of both $R(\psi, \phi)$ and $C(\alpha, d)$ as well as P_{in} . Although only R is an intrinsic property of the reflecting surface, the measurement cannot be made without C : the best one can hope for with this kind of measurement is a combined measurement that expresses the received power as the angle of illumination is varied.

3.4.6. Reflectivity Tests

Optical power was measured as it reflected from various materials as a function of alignment. Tested materials included papers, painted surfaces, mirrored surfaces and a retroreflective sheeting, which reflects light parallel to the incident path. To make these measurements, we built a test stage by which we could fix the polar and azimuthal angle of a fiber with respect to the test surface. The reflection test stage had a mount dovetailed to the stage and aligned to point a collimator at the target surface. The polar and azimuthal angles were indicated. The stage is shown in Figure 3-17. One end of the fiber was attached to the light source. The circuitry was powered with GaAlAs laser diodes operating at 820 nm and either 10 mW or 48 mW. Both lasers were pigtailed with fiber, and short lengths of fiber connected the laser to a power splitter and a power meter. Connections were made with SMA ferrules.

In the first tests a single optical fiber, terminated in a collimator, was aimed at a reflective surface. Laser light was launched down the fiber, reflected by the test surface and guided back through the fiber. The returning power was split, half being sent through an optical coupler to a power meter. Power readings as a function of the angle between the fiber and the perpendicular to the surface were taken for each test surface.

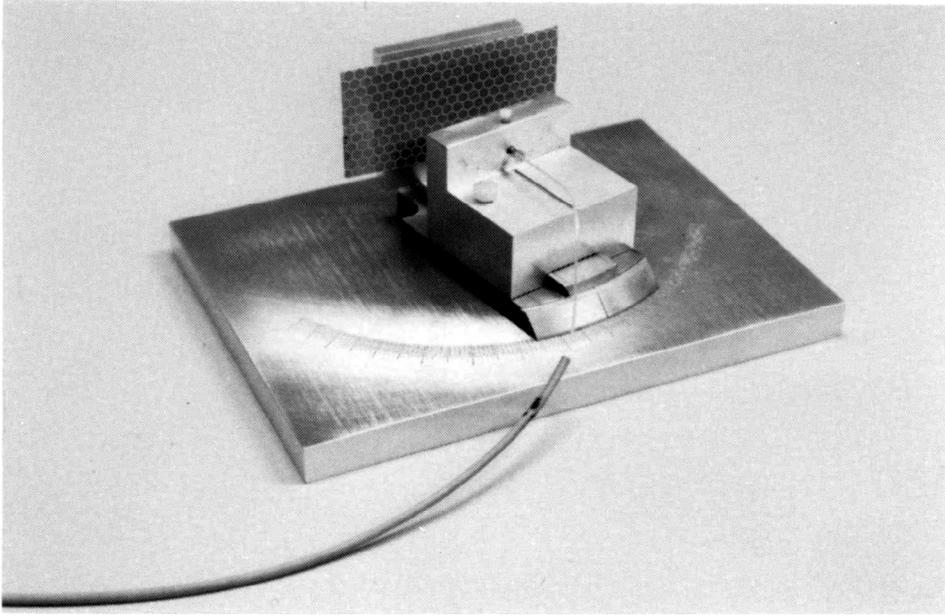


Figure 3-17. Photograph of reflection test stage

Figure 3-18 shows how light is reflected back in the direction of its source by a special kind of surface called retroreflective. An ordinary mirror reflects at an angle equal to the incident angle. Because a ray returning from a retroreflective surface has been reflected twice, it leaves the surface in a direction parallel to the incident ray. The lateral displacement evident in Figure 3-18 is small if the corner reflector of the surface is small. In the samples we tested the offset was considerably less than 1 mm.

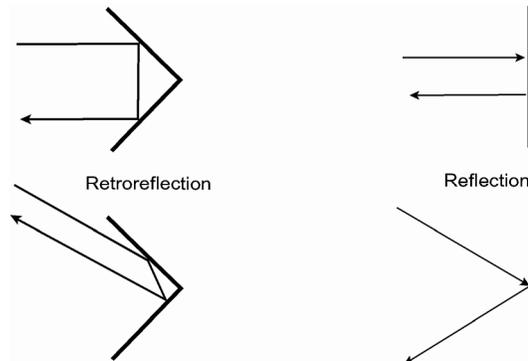


Figure 3-18. Retroreflection

3.4.7. Discussion of Results

In Figure 3-19, a graph of the reflectivity of a mirrored surface over a range of angles shows a peak when the fiber is positioned within ≈ 1 degree from the normal. In most applications, this alignment sensitivity would be a drawback. The retroreflective surface, however, shows less change with variation in angle. Although the maximum reflection is less than that of the mirror's peak range, the retroreflective material functions satisfactorily within ± 55 degrees from the normal.

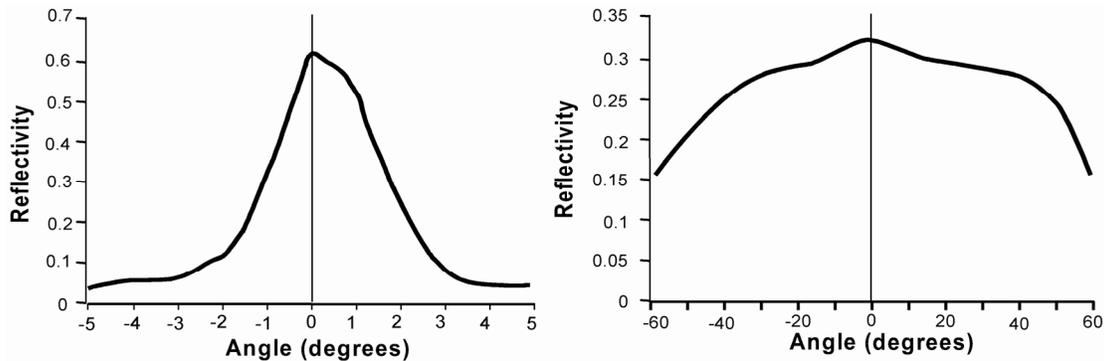


Figure 3-19. Reflected power, mirror and retroreflector

In a two-fiber system it was found that best results were obtained when the second fiber was much larger (several times the diameter) than the first fiber. Also, an LED has a more diffused power distribution than a laser so alignment becomes less critical when an LED is used as a light source. A higher numerical aperture correlates with a higher coupling efficiency, enabling splices and connections that have lower loss.

A mirror-like surface is not the best candidate for a reflective dot in the position-pickoff unit of the field meter. For maximum response, the collimator and dot have to be aligned to better than one degree, and such alignment is practically impossible. The retroreflective sheeting provides a weaker response than a mirror at its best could, but can give that response even under a large misalignment.

3.4.8. Bewley's Lattice

A fiber optic system is made up of many lengths of optical fiber connected by ferrules, couplers, beam splitters. Each of these components modifies the optical signal. The cumulative effect of all modifications is complicated, and it is worthwhile to use a model to predict the overall effect.

A time-space diagram was developed by Bewley (1963) to describe the successive reflections of traveling waves on a power transmission system. This reflection lattice was adapted by us to model optical reflections in a fiber optic system and to predict power losses as a function of

system components and the complexity of their connections. These connections are described in the model as nodes, each with its own reflection, transmission and loss characteristics. The model tracks successive transmissions and reflections at each node.

The optical model differs from Bewley's electrical model in several ways. First, there is an absence of attenuation factors. Whereas in transmission lines, loss is partly a function of line length, the optical fibers in this model are assumed not to attenuate as a function of distance. Second, since the light source is not sufficiently coherent to provide a single wavelength, the effects of phase cancellation are taken as insignificant.

3.4.9. Description of Optical Lattice Model

Each component of the system is described as a node, interconnected to other nodes. Each node is assigned a transmission and reflection coefficient. These coefficients modify light passing through the node by each of two paths, transmitted and reflected. Four magnitudes of power are described at a node: that transmitted in, transmitted out, reflected in and reflected out. Successive reflections and refractions are shown as layers of repetition. Light passes through each node in two directions, represented as left and right arrows in Figure 3-20. As light is transmitted into a node, it is partly transmitted and partly reflected. The transmitted portion enters the next node in the system. The reflected portion reenters the previous node. By implementing the model using a spreadsheet program, this connectivity is easy to represent. Light which is reflected into a node is partially passed through, joining the light being reflected back to the previous node; and partially reflected, becoming part of the transmission out to the next node. These portions of light are split again at each node they encounter into transmitted and reflected fractions. Figure 3-20 represents the light paths at a typical node.

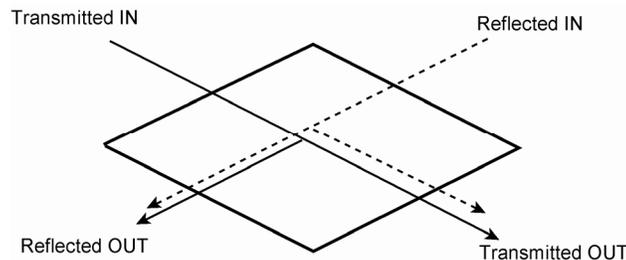


Figure 3-20. Model of a node

3.4.10. Application of Model

Our model assumes that there is no interference between components in any segment of the system and that the transmission and reflection coefficients are linear, that is, valid at any power

level. The model describes any component in the system as a point where light paths cross and are modified. The power transmitted out of the ultimate node is the sum of these successions. The model may be expanded to represent any number of nodes.

3.4.11. Sample Program

Figure 3-21 represents 3 levels of reflection in a four-node system. In this example, the nodes are the source, two ferrules, and the connection to the meter. The source is assigned a transmission coefficient of 1. The power leaving the source and entering the fiber (the "power in") is defined as 100%. The ferrules and meter are each assigned a transmission and reflection coefficient, which may equal 1, or be <1 to indicate a loss due to that component. Each light signal is split into a transmitted portion and a reflected portion. These are derived by multiplying the incoming signal by the coefficient of transmission or reflection. This model is a way of mapping the direction and magnitude of an optical signal through a system.

The model can be used to find the effect of surface properties on a given configuration if the various other loss and reflection coefficients are known. Alternatively, for any specified input power and measured reflected power, the program can be used to determine pairs of coefficients that will give the same value of power out. These coefficients can then be used in modelling other arrangements. The coefficient pairs were plotted for several setups in Figure 3-22. Note that the slope of one line differs conspicuously from that of the others.

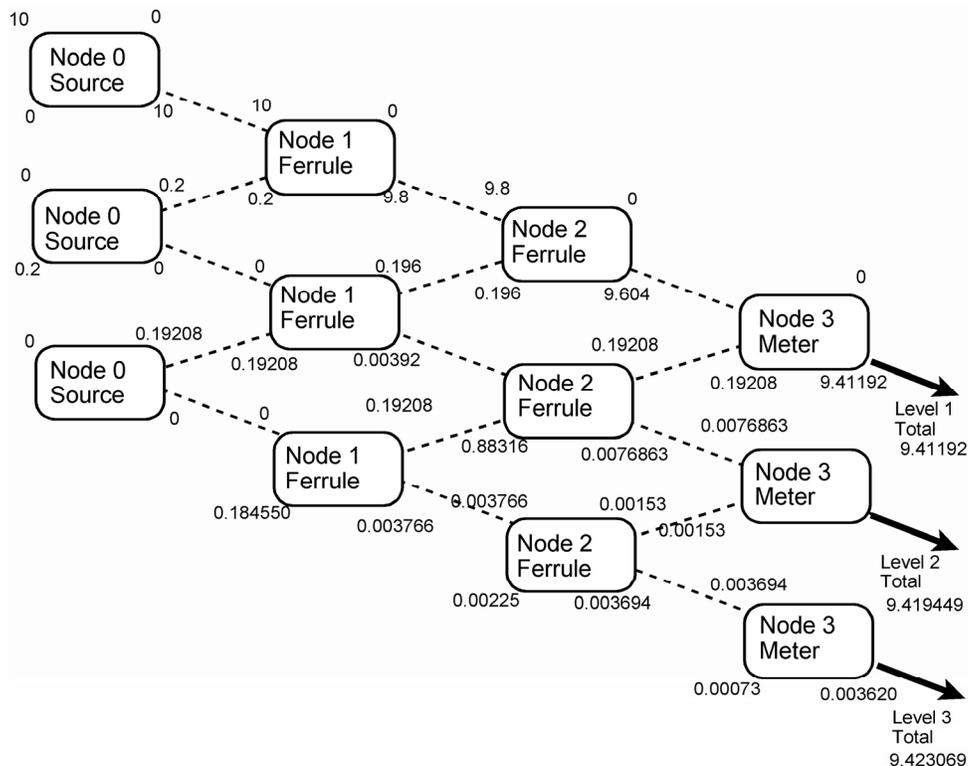


Figure 3-21. Sample program

The modified Bewley model was used to characterize several simple systems. As components are moved, the solution to the model differs significantly, as shown by the different slopes of lines representing pairs of transmission and reflection coefficients. This can be seen in Figure 3-22. The reason is not clear. Possible explanations include uncertainties in connector alignments, and the effects of distinct optical modes that are not mixed in the relatively short lengths of fiber used. More detailed investigation is evidently needed to understand the nature of the surface/fiber interactions.

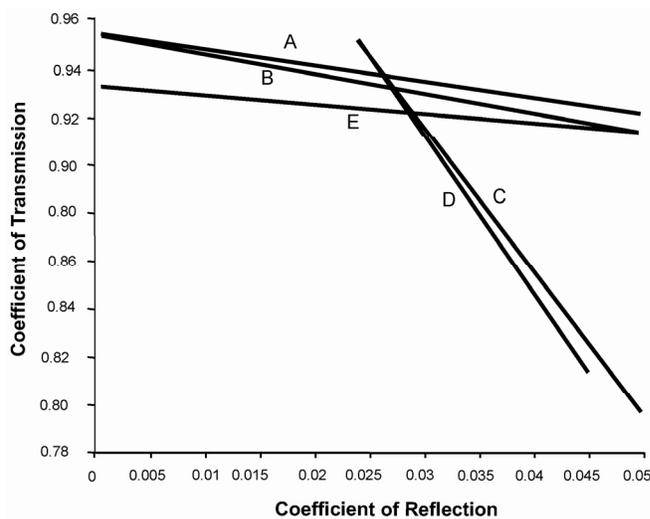


Figure 3-22. Bewley curves

4. SYSTEM CONSIDERATIONS

A survey in Electrical World (1988) summarizes the annual capital expenditures of the nation's utilities, broken down into generation, transmission and distribution. Figure 4-1 is a graphical presentation of the data.

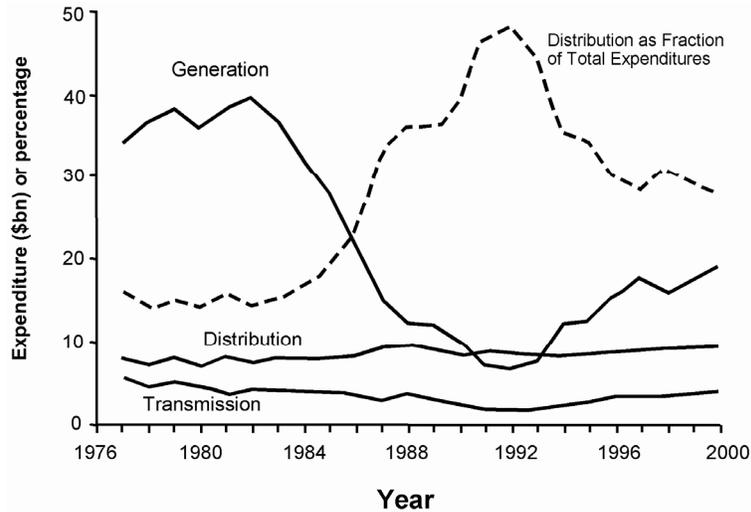


Figure 4-1. Annual capital expenditures (billions of 1988 dollars)

The late 1970s and early 1980s saw strong growth in generation capacity. Because new generation has to be integrated into the transmission system, this was also a period of relatively high expenditures on transmission. As a fraction of the total, investment in the distribution system was quite low. In the mid-1980s, generation (and hence transmission) growth slowed, largely in response to changes in the regulatory situation facing most utilities.

Although capital spending for distribution has not grown significantly, distribution represents an increasing fraction of total capital expenditure. This is expected to continue into the early 1990s. Not only will generation spending continue to fall, but distribution expenditures are expected to rise with the increasing use of underground distribution systems. By 1992, distribution is forecast to account for almost half the capital spent by the nation's utilities. In round numbers, this will amount to an annual expenditure of \$8 billion. Because generation expenditure is expected to resume in the mid-1990s, distribution expenditures expressed as a fraction of the total are predicted to fall. However, note that distribution expenditures expressed in constant 1988 dollars are expected to rise steadily at least until the end of the century.

With an investment of this magnitude, the distribution system certainly deserves careful operation. With a potential market of this size, it is surprising that the equipment manufacturers are not showing a more aggressive attitude towards distribution automation. In this section of the report, we address some of the reasons why distribution automation is not being actively pursued, except by a handful of individuals.

It is our premise that, in addition to the problems with communications, the lack of “systems engineering” is an important reason that automation of the distribution is not being more actively pushed, either by the manufacturers or the utilities. By this is meant that a successful distribution automation system will work as soon as it is installed, without further engineering by the purchaser; is designed from the outset to be capable of all possible automation functions, even though some are not implemented; and is reasonably friendly to operate and maintain. This has not been done. There really seems to be no system for the manufacturers to sell or for the utilities to buy.

The utilities have shown themselves to be reluctant to perform systems integration for the collection of hardware and software that represent the only available components of a potential system. In our opinion, this reluctance is justified. Some utilities have spent considerable amounts of time and money trying to make a collection of components into a system, only to encounter insuperable problems in the end. It is beginning to be recognized that distribution automation has to be “system engineered” from the outset.

The manufacturers apparently perceive this as the utilities shying away from distribution automation. Some of the manufacturers have offered partial distribution automation systems in the past, and have not met with commercial success. When one considers what was really being offered, however, lack of sales should be no surprise. Company A offers to sell a utility a distribution automation system that can read meters, for example. “If you add modems from company B, or radios from C, you can get the readings back to the control center,” they say.

In the world of distribution automation, a glance at the advertisements in any recent issue of the trade magazines shows that we have one manufacturer offering, say, transformers, another one sensors, and another “communications products.” There is no hint that these components might be interconnected to form part of a data acquisition system. Several of the advertisements contain words that indicate the product will work with telephones, radio or fiber optics, and with a variety of data protocols. Right away, one suspects that implementing a distribution automation system using this particular product is going to involve some systems engineering.

This is true, not just of the communications problem. The same remarks apply to sensors. A variety of low-energy sensors is now available, capable of measuring the most common power system parameters. A range of output options faces the poor customer, who must decide whether to use a low-current output, a low-voltage output, or (O Heaven forbend!) sort out the options for a digital interface.

Creating a new distribution automation system presents a unique opportunity to abandon the notion of compatibility with existing standards. While there are large financial and intellectual investments in the existing technology, especially in the transmission system, existence is not a justification for continuing indefinitely the same methods or maintaining compatibility. Of course, the large existing investment cannot be abandoned overnight, but it is time to establish some new standards that recognize the technical advances that have been made since power system measurement and control adopted the present standards, over 80 years ago.

The issue of standards is worthy of closer examination. We suggest that a successful distribution automation system will break completely with many long-established standards in the power industry. While the standards to be employed for such things as measurements and data transfer will be internally self-consistent and compatible, they will not be compatible with any of the older power system standards. The next section examines the question of standards.

4.1. Standards

The establishment of standards is a crucial part of creating a market. The timing for standards frequently involves a compromise between setting the standard too early, so that the industry is unable to take advantage of technological developments, and setting the standard too late, so that the market becomes fragmented, with each manufacturer having his own standard. Early standards may limit innovation; late standards may hinder market development.

In practice, standards in a developing industry leap-frog one another. There are examples in the consumer electronics industry. European color television is better than American television because it uses a standard (PAL) that was developed later than the American NTSC. Technological advances had been made between the times that the two standards were adopted. On the other hand, America had color television for several years before it was available in Europe. In a similar vein, Britain had black and white television according to a 405-line standard established before WW II, which proved later to be incompatible with color. Therefore, when Britain wanted to provide a color service, an entirely new set of standards had to be developed. The European 625-line PAL standard was adopted. For many years, British TV manufacturers were obliged to make receivers which were compatible with both standards, a costly proposition. (Eventually, the older, 405-line standard was dropped.)

The standards for instrument transformers in the power industry have remained unaltered for more than 70 years. The accuracy requirements for metering-grade transformers, and the dynamic-range requirements for relaying transformers, may have improved during the period, but the basic concept of 5 amp for CTs and 120 V for PTs at rated value has not changed since shortly after the turn of the century! This situation is very unusual. Indeed, it is almost without parallel, because electrotechnology has advanced considerably during the same period.

4.1.1. Changing Standards in Other Industries: Consumer Electronics

As an example of the effect of these advances, consider the technology associated with the recording of sound. In the early days of the technology, sound was recorded as a wavy groove on a disk rotating at 78 rpm. A stylus retraced the groove on playback, and caused a diaphragm to vibrate, reproducing the sound waves. As transducer and reproducer became separate, and electronic amplifiers were introduced, it was possible to reduce the speed of the disk and still improve the quality of reproduction. Standards came into being for 45 rpm, 33-1/3 rpm and even 16-2/3 rpm. The recording industry, normally very conservative, adopted the new technologies because the improved quality seemed to presage increased sales.

In the 1980s a complete break with this technology was made by Philips of the Netherlands and Sony of Japan together. Jointly they developed the digital compact disc. In this system, the audible signal is sampled 44 thousand times per second and digitized. The resulting digital information is stored, along with an error-correcting code, on an optical disc, which is read by a laser beam during playback.

This example is instructive because Sony and Philips between them had to define the complete system. The method of sampling, digitizing, error correcting and recording had to be defined, as well as a medium for data storage. In addition, the equipment to make the digital disks, and the equipment to be sold to the consumer in order to play them back, had to be designed and made.

This kind of break with the existing technology may be required for distribution automation to be a commercial success.

4.1.2. Changing Standards in Other Industries: Industrial Electronics

Another example, not in the consumer electronics area, is provided by the situation facing Hewlett-Packard as they introduced HP-IB. For many years Hewlett-Packard has been known as a manufacturer of test instruments of high quality. Some while ago, they branched out into the computer business and began making a series of minicomputers. Many Hewlett-Packard computers found application in data acquisition systems. However, for a period that lasted many years, interfacing Hewlett-Packard's computer to Hewlett-Packard's digital voltmeter, for example, was a matter of considerable engineering. Special connectors had to be wired, and special I/O driver software had to be written.

Eventually, Hewlett-Packard changed all of this with the introduction of HP-IB. A single special-purpose connector, from a single I/O card in the frame of the computer, could connect to the first of a series of peripherals that could be daisy-chained together. The I/O driver was available off-the-shelf, written by Hewlett-Packard. A language and protocol for the parallel bus was also specified by Hewlett-Packard. The data rate on the bus was fast enough (10 Mb/s) that a large number of users could be on the same bus. At the same time that they introduced HP-IB, the company produced a number of peripherals specifically for HP-IB applications. It was then possible to plug a plotter, a real-time clock, a voltmeter, an oscilloscope and various other pieces of test equipment into the computer. Naturally these various peripherals were only available from Hewlett-Packard.

Later, other manufacturers began producing equipment that was compatible with HP-IB, and ultimately the IEEE adopted the standard and renamed it IEEE-488. Note that in a way similar to the Philips-Sony development of the digital compact disc, this is an example of a small segment of the industry adopting a method which later became a *de facto* standard for the remainder of the industry.

It is suggested that distribution automation in general would benefit greatly from the formation of a consortium of manufacturers that would act together to define new standards for hardware and software, capable of meeting all foreseeable distribution automation requirements.

If the technical problem (communications and control) can be solved economically, the incentive is there to invest the effort required to do the systems engineering, and develop the new standards. It is therefore necessary to present a convincing economic case.

4.2. The Economics of a Fiber-based Distribution Automation System

The utility industry is one of the most capital-intensive businesses in the country. Economies of scale have driven extensive development efforts aimed at generation and transmission system cost-reduction. A 765-kV transmission circuit might cost \$200,000.00 per kilometer to build, and if it were transmitting 1000 MW it could be carrying enough power to supply a half-million residential customers. This means a capital investment in transmitting power of 40 cents per km per customer, or perhaps \$40.00 per customer per circuit. Because of the large number of customers involved, reliability of supply must be obtained by providing alternative circuits. As a result, the transmission part of a power system is always highly interconnected. Loss of one, and frequently two, transmission circuits does not result in power outage to any customer.

The situation is different in the distribution system. Circuit costs are lower, of course, because of the lower voltage levels and smaller size of equipment. On the other hand, the number of customers served per circuit is also lower. A 12-kV feeder might cost \$10,000.00 per km, to serve only 35 customers. This is almost \$290.00 per customer, seven hundred times the cost per customer-km of the transmission system example given above. It is, of course, this enormous economy of scale that has led the utilities to the present levels of high-voltage transmission, and the high degree of interconnection. Because the cost would be so much higher than in the transmission system, and because of the smaller number of customers involved, distribution circuits are rarely interconnected.

The result is that, by and large, reliability of service for most customers is determined by the distribution system. Several aspects of distribution automation are aimed at improving this reliability without the necessity for interconnection.

But distribution automation has many aspects. The reason that one utility might be considering distribution automation could be quite different from the reason another is considering it. A utility that has a peaking-capacity shortage might be more interested in customer-side control, which addresses peak demand, than they would in the reliability and lost-revenue aspects.

The economics of each application area must be clearly demonstrated if the idea of distribution automation is to become accepted. It is not easy to calculate the benefits of all the distribution automation functions. Some of them, such as the reduction of distribution system losses, do have readily calculable benefits. For other functions, the dollar value may be harder to establish. (An example of this is improved service reliability.) Yet, these are the kinds of issues that must be honestly addressed. The idea is to go beyond the usual presentation of benefits, such as those shown in Table 4-1.

Table 4-1. Benefits of distribution automation

Function	Benefit	Value to Utility
Feeder Automation	Isolate faults Redistribute load	Reduce lost revenue Reduce losses Defer system improvements
Load Management	Reduce system peaks Control loading in distribution system	Lower generation costs Customer satisfaction Better system performance in emergencies Reduce losses
Volt/VAr control	Local VAr supplies Improved voltage control Load control	Reduce losses Customer satisfaction Better system performance in emergencies
Substation Automation	Higher substation reliability Higher equipment loading	Reduce spares, O&M costs Defer replacement
Cogeneration/DSG Control	Reduce system peaks Control loading in distribution system	Lower generation costs Defer generation addition Defer system improvements Reduce losses

In the next section, we shall examine the economics of some of these functions. We begin by outlining the general approach.

4.2.1. Present Value Analysis

A useful way to evaluate a project is to use the methods of discounted cash flow (DCF). In contrast to simply comparing, say, rates of return, DCF accounting techniques enable the future profitability of a project to be evaluated whether the profits are earned quickly or slowly.

The technique of present value analysis provides a way of comparing the cost of implementing a function with the projected savings. While the result of such an analysis is unambiguous, it must not be thought that it is error-free (because assumptions are necessarily made about factors beyond the control of the utility, such as interest rates) or that there are no alternatives. A utility might have several ways to ask the question, “Does distribution automation make sense?” For example, they might want to know how long it would be before an installation paid for itself, or whether some particular distribution automation function was more cost effective than a particular alternative, such as reconductoring a line. We shall present some examples that are more specific than this, answering the question, “Is it better to invest this amount of capital in this distribution automation function or not?” Thus, while time appears as a parameter in the equations, it does not appear in the solution. However, the method does lend itself to comparing alternatives.

We use present value analysis to compare the total cost of raising the capital to implement a distribution automation function with the cost of not implementing it. Thus, for example, if there are energy savings (in kWh) associated with a given function, the value of these savings can be compared with the cost (in \$) of implementing the function.

The mathematics are readily derived. If an amount of money P (the starting principal) is invested at annual interest rate x (assumed constant), the amount $P(1 + x)$ is returned at the end of one year. If this is reinvested (compound interest), the amount $\{P(1 + x)\}(1 + x)$ is returned at the end of two years, and so on. This is easily generalized: most spreadsheet programs, and some calculators, calculate compound interest by applying the formula

$$S = P(1 + x)^n \quad (4-1)$$

where S is the compounded amount at the end of n periods. If we normalize by dividing by the principal, we can see why the quantity $(1 + x)^n$ is sometimes called the accumulation factor. It gives the amount by which P must be multiplied to find the compounded amount at the end of n periods.

We can rearrange to solve for P :

$$P = S(1 + x)^{-n} \quad (4-2)$$

Now, the quantity $(1 + x)^{-n}$ is the discount factor, in contrast with the accumulation factor. (This can be seen by dividing by S . Note that the discount factor is less than unity.) If the discount factor is multiplied by the sum expected at the end of a period, the result is the present value, or present worth. Thus, \$110 next year is worth \$100 now, if the interest rate is 10%.

Since this expression for discount factor was derived from the expression for compound interest, it can be applied to periods longer than a year, although the result is less intuitively obvious. In any case, the expression is mostly used to find the present value of a series of investments made over a number of years. This answers rather a different question.

Suppose, for example, that we implement a distribution automation function that saves us \$110 per year. It is clear that, if the savings only last one year, and the interest rate is 10%, the present value of the installation is \$100. What if we get another \$110 in the second year? Equation (4-2) tells us that the present value of having \$110 in the second year is \$90.91. The present value of the whole series of (two) cash flows is therefore \$190.91. If we add all such future cash flows, we get the net present value (NPV), which can be defined as follows:

$$\text{NPV} = \sum_{i=1}^n S_i(1 + x)^{-i} \quad (4-3)$$

Here S_i is the return expected at the end of the i th period. In other words, the NPV is the sum of the present values of all the future cash flows. This expression can be simplified for comparing functions that have a constant return each year, or (and this is especially easy if a spreadsheet is used for the analysis) the return can be variable. While the variable x was the interest rate in the

compound interest expression, it is sometimes referred to as the return on investment (ROI) figure in NPV calculations.

For our purposes, the method has basically five steps. Suppose we wish to evaluate an energy-saving function:

1. Compute the energy savings (in kWh), and from this an annual value of energy saved (in \$). This may not be quite as straightforward as it sounds. The cost of energy may vary as a function of the time of day at which the energy would have been used, for example.
2. Compute the net present value of these savings, assuming a lifetime (derived from the characteristics of the hardware) and a reasonable return-on-investment figure.
3. Compute the annual carrying charge for the capital investment. This will be greater than the interest rate. Strictly speaking, the revenue requirements of a distribution automation investment should include consideration of factors such as ROI, depreciation, taxes, and operation and maintenance costs. This is why the company accountant is such a valuable employee.
4. Compute the present value of the annual carrying charge, using assumptions similar to those in step 2.
5. Compare the net present value figures of the savings and the investment.

We will now apply this method to a few distribution automation functions.

4.2.2. Feeder Automation: Loss Minimization

Losses caused by the resistance of distribution feeders can be significant. The obvious way to reduce them is to reconductor the feeder; an alternative is to reduce the losses by switching feeders so as to balance the currents in the various circuits. It is clear that, since losses vary as I^2R , equal currents in similar circuits minimize the losses. Circuit switching can also be used to restore the maximum amount of load following a fault. This aspect of the technology of feeder switching has been addressed in a number of IEEE papers.

Baran and Wu (1988) cast the reconfiguration as a minimal spanning tree problem. Starting with a feasible solution, branches are exchanged one at a time. Their search results in a locally optimal solution. Liu, Lee and Vu (1988) aim at a globally optimal solution. Shirmohammadi and Hong (1988) describe an approach that may result in a solution that may be only “near-optimal.” This work shows that feeder reconfiguration is technically possible, mainly in terms of post-fault load restoration. However, the approaches presented in these papers are mathematically almost impenetrable, perhaps because the authors have attempted to obtain a general solution, taking into account all the system constraints. While in any individual case the problem is probably rather simple because there are usually few options, a computer-based

solution that could be implemented in a distribution automation scheme should avoid the need for case-by-case algorithms. However, none of these papers discuss the economics of alternatives to feeder reconfiguration.

Economic analysis is the goal of a paper by Boice, Gursky and Trad (1988). They present a more broad-brush approach to evaluating the economic impact of the cost of losses in the whole power system (from production to distribution). Examples given include the effect of tap-changing on 345/138-kV transformers, and the effect on conductor selection for a new 138-kV line. The second example is incomplete in the sense that the total cost calculated for the line is not compared with the costs for another selection. The first example, however, is instructive in that it compares the economic effects in a number of cost categories. The demand-charge reduction for generation in the example is shown to be by far the largest effect. It is almost an order of magnitude larger than the demand-charge reduction for transmission and distribution and five times larger than the energy charge savings.

If this result is typical, it would be unlikely that loss reduction by feeder switching would be economically attractive. Let us examine this proposition by means of an example adapted from Burke (1988) with permission.

Assume that there are two feeders that are equally loaded for 21 hours each day, but that have non-coincident peaks during the remaining three hours. The original configuration for this system is shown in Figure 4-2, which also shows the load currents seen at the substation during the peak load on feeder A.

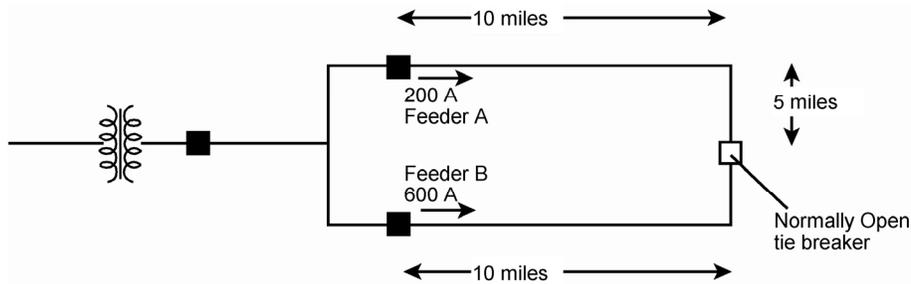


Figure 4-2. Original feeder configuration

Suppose, now, that an additional breaker could be added to the longer of the two feeders, so as to balance the loads during this peak. This arrangement is shown in Figure 4-3.

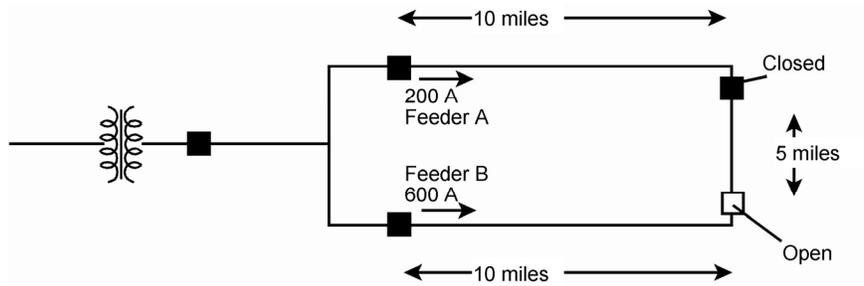


Figure 4-3. Feeder configuration with automated breaker

Losses in these two configurations can be compared by assuming that the loads are evenly distributed and that the wire resistance is everywhere the same. Under these assumptions, it is readily shown that the I^2R losses for one phase of a feeder are given by $(I_0^2R)/3$, where R is the total resistance of the feeder and I_0 is the current seen at the substation. Three phase losses are then simply (I_0^2R) . If we designate the resistance per unit length by r , then the conductor losses for the two configurations can be calculated. For the original system, the losses L_o are given by

$$\begin{aligned} L_o &= (600)^2 \times 15r + (200)^2 \times 10r \\ &= 5.8 \times 10^6 r \end{aligned}$$

For the automated version, the losses L_a are given by

$$\begin{aligned} L_a &= (400)^2 \times 15r + (400)^2 \times 10r \\ &= 4 \times 10^6 r \end{aligned}$$

This is a 30% decrease in the losses. If r is 0.5Ω per mile, the change in losses is $0.9 \times 10^6 \text{ W}$.¹

Let us assume that the load factor for the 3-hour peak is 90% (after all, this is peak load) and apply a conventional rule of thumb for the average losses:

$$\begin{aligned} \text{Loss Factor} &= 0.15 (\text{Load Factor}) + 0.85 (\text{Load Factor})^2 \\ &= 0.82 \end{aligned}$$

¹ These loss figures seem rather high. Although the parameter values used here are based on the original work by Jim Burke, some comment seems in order. Assuming that the distribution circuit in question is overhead, and that the cable is the customary ACSR (Aluminum Cable Steel Reinforced), it would be unusual to allow 600 A in a circuit whose resistance was 0.5Ω per mile. Such a cable would likely be limited to about 300 A. A 600 A cable would likely have a resistance of perhaps $0.1 - 0.14 \Omega$ per mile, and losses around a quarter of the values here.

Since the loss factor is defined as

$$\text{Loss Factor} = \frac{\text{Average Loss}}{\text{Peak Loss}}$$

we can calculate the average loss as 0.66 MW for the three-hour peak period. If this number is applied for 261 workdays per year, the total energy saved is 516 MWh. If the cost of electricity is 5 cents per kWh, the annual cost savings is \$25,792. To apply the present value method, we need to know the cost of implementing this automation system. Let us suppose that the capital cost of the new circuit breaker and the modifications to the existing tie point is \$60,000 over the anticipated lifetime of 20 years. The interest rate for a cash investment is assumed to be 12%, and the (levelized) carrying charge rate on the hardware is 20%, higher than the interest rate because of the factors listed earlier. The annual carrying charge is therefore \$12,000.

The present value of the investment in hardware can readily be evaluated. The easiest way is to use a spreadsheet program: in Lotus 1-2-3, the expression @PV(payment,interest rate,number of payments) can be used, yielding a value of \$89,333 for the distribution automation system. The present value of the savings is seen to be \$192,651. Consequently, over the life of the installation, the present value of the benefit to the utility is \$103,018.

The same number can also be derived by computing the present value of the difference between the levelized annual cost of the distribution automation investment and the annual savings. This simplicity arises because the costs were levelized and the savings assumed constant.

The comparison can be made even in the case that the savings or the costs are not constant for the lifetime of the equipment. Equation (4-3) allows us to vary the return in each period, and this function is also available in spreadsheet form. In Lotus, the function @NPV(interest rate,range of cash-flows) can be used when the cash flow varies from year to year. In this way, for example, it may be shown that even if the savings due to loss reduction are \$20,000 in the first year, \$15,000 for the next five years and \$5000 thereafter, the distribution automation scheme would still be economical.

Perhaps the savings are unrealistically high because the losses before modification were high. Evidently the distribution automation system would pay for itself if the monthly savings were \$12,000, that is, if the loss savings were roughly half the value used in this example. Our point is not to show that line switching is economically sensible. It is to indicate that an unambiguous answer to the economics question can be obtained. In the particular case of line switching, the number of opportunities to implement a scheme like the one described here are few. Lines from the same substation generally have similar load cycles, so there would be little or no diversity of the peak demands.

In another example in his paper, Burke analyses the case of a three-feeder, two-substation situation. In this situation, dissimilar load cycles are more likely. In this example, a total savings

of \$4000 per year (for all feeders) was realized. With similar assumptions to those used earlier, this would be economical for a capital expenditure of no more than \$20,000. Whether or not this would be feasible might depend on whether the distribution system already had suitable circuit breakers installed.

4.2.3. Feeder Automation: Volt/VAr Control

Line losses are minimized by supplying reactive power locally, as far as possible. Often a line is furnished with a fixed value of capacitance at one location, and the ability to switch in other banks (possibly at other locations) as the load increases. Such switching is usually based on time, based in turn on a knowledge of the time variation of kVAr loading. This is open-loop control. It has been said that closing the loop, and installing an integrated volt/VAr system can pay for the entire distribution automation system (Kendrew and Marks, 1989). Can this be true?

Once again, we examine a situation studied by Burke. Suppose we wish to consider the economics of an automated capacitor switching system. First, it must be realized that we have to compare the cost of an automated system with that of open-loop switching, not with no switching at all. There are probably several viable open-loop alternatives: in his example, Burke considers two.

The feeder chosen was a 13.8-kV 4-wire configuration, 7 miles in length. The daily load cycle was quite pronounced, with a minimum value of 100 A between 10 pm and 6 am and a peak of 300 A between 5 pm and 8 pm. For the remainder of the time there was a 200-A load. Of course, it would be possible to compensate precisely for the reactive demand if it were known in advance as precisely as the current. This is not typical, nor is the precise timing of the cycle.

Using a computer model, Burke arrives at annual savings of the order of \$450 for the controlled capacitor scheme for this feeder, compared with open-loop alternatives. Bearing in mind the \$4000 savings calculated for three feeders that are switched between substations, the capacitor scheme seems to have been evaluated about correctly. It can be said that it would be economical to implement such a system if the additional capital cost were less than about \$2000. This is scarcely going to pay for an entire distribution automation system.

On the other hand, utilities are obliged by statute to hold the service voltage between some particular limits, and the flexibility of control afforded only by the automated system may be justified on these grounds, at virtually any cost.

An interesting approach that combined reconfiguration and capacitor control was described by Lee and Brooks (1988). During 1984 and 1985, the Pennsylvania Power and Light Company collected time-of-day load data at 15-minute intervals on six feeders in the company's Lehigh Division. Using these data, and in collaboration with the Advanced Systems Technology Division of Westinghouse Electric, the effects of system reconfiguration were studied. The switching approach consisted of removal of capacitors, reconfiguration in the optimal arrangement and, finally, re-application of capacitors, not necessarily in the same locations as

before. Additional switches were assumed to have been installed if needed. Losses in the original configuration and the final configuration were compared.

The study could not have been performed without the extensive load data base. The detail of the data made it possible to analyze the effect of switching on losses, not only to take into account seasonal variations in the load, but also diurnal variations. It was the ability to switch on a daily basis that resulted in the largest benefit. In the system studied, losses were reduced over 14% (2500 MWh), with an annual estimated savings of over \$110,000 for 26 feeders.

The overall system efficiency was calculated to rise by 0.2% to 98.95%, indicating better use of generated power. This small increase in efficiency would be very important on a company-wide or national basis.

While one might be concerned about the effect of such frequent operation on the switches themselves, it may be pointed out that such switching as that required in the PP&L study could scarcely be carried out manually. Lee and Brooks point out that manual switching can have benefits in terms of seasonal reconfiguration, but the benefits are much smaller.

4.2.4. Economic Analysis of Other Functions

Some of the other functions of distribution automation can be studied in much the same way as the examples given above. The concept of load management, which started in Europe, has probably received more attention than any other application, and an analysis of it will not be repeated here. The interested reader can find economic studies of European load management practice reported in Critical Analysis, (1977). The relevance of load management to the U.S. was examined by Morgan and Talukdar (1979). Since then, the economics have been examined in a number of papers and reports. In the early 1980s, Nelson (1981) showed that air conditioner load management makes sense for a small utility paying a demand charge, and Fiske, Law and Seeto (1981) of Pacific Gas and Electric showed that air conditioner load management would benefit their utility, society and the company's ratepayers. Evidently the economics have now been convincingly demonstrated: water heaters and air conditioners have been the subject of utility control in many areas for many years now.

It is harder to put a value on increased reliability. The value of lost revenue is, in most cases, trivial. Roy Billinton of the University of Saskatchewan has been considering reliability issues for some time. In a survey reported by Burke, he attributes a cost of \$1.50 per kW to a 2-hour feeder outage. This is based on the costs of litigation, not energy. While lawsuits resulting from outages are rare, they can evidently be quite costly to the utility. Assume that a typical feeder is 7 miles long and suffers 0.15 outages/mile/year. The connected load is 20 MVA. Using Billinton's figures for cost, outages on this feeder might cost the utility \$31,500 annually. If distribution automation (reconfiguration) could reduce this figure by a factor of, say, three, the savings would be over \$20,000 annually. This far exceeds the savings attributable to most other distribution automation functions.

Meter reading will probably be less a matter of economics than of complying with PUC regulations. The regulatory authorities in most states would like the customer's meter to be read every month. However, difficulties with access to the meter have resulted in a situation where some estimated readings can be used for billing. Further, most utilities are prepared to bill for a while on the basis of the customer's own reading of the meter. The end result is that the utility may be required to read the customer's meter regularly, but the frequency may be as low as every six months, or even every year.

Both the regulatory authorities and the utilities would like more frequent readings. Automated meter reading may be the only practical way for utilities to comply with changing rules. Thus, while there may be interest in the topic of automated meter reading, the economics may never be demonstrated in a clear-cut way. If the utility has no choice, the best they can hope to do is find the lowest cost way of complying.

4.2.5. System Redesign

In one of the earliest papers proposing microprocessor control of the distribution system, Lyons and Thomas (1981) suggest that economic analysis must await data from demonstration projects. For many of the distribution automation functions listed earlier, the economics can be shown to be favorable. Those functions, however, are somewhat unimaginative. Another aspect of distribution automation, and one that has not been explored to any extent in the literature outside Europe, could be called system redesign. We would like to take the opportunity to bring this possibility to the attention of the reader.

By system redesign is meant the reconsideration, from first principles, of the way the distribution system operates, and consideration of the way that similar performance might be obtained with less costly components if an extensive communications system were in place. Thus, a study in the United Kingdom (Black, Formby and Walker, 1985) showed that 60% of switching operations on the 11-kV system were for the purpose of isolating other similar equipment for maintenance, and 20% were post-fault operations made to identify the faulted section (rather than to isolate it). Each of these operations required a site visit, and was therefore considered costly and time consuming.

If a low-maintenance, low-duty kind of switchgear could be used, the number of switching operations could be reduced. In order to maintain the existing quality of supply, the operation of the feeder system would have to be automated. A communication and control system that would enable the identification of a faulted zone, and its subsequent automatic isolation, would be necessary. The newly available information from the distribution automation system would obviate the need for the 20% of switching operations that were made for fault-identification purposes. If the feeder automation system were capable of isolating a faulted feeder, low-maintenance low-duty switchgear (such as switchgear that could only be operated dead) could be used to disconnect the faulted section so that the main circuit breaker could reenergize it rapidly.

In the case of the work of Black *et al.*, the use of dead operating switchgear was estimated to result in a savings of about 30% in the replacement of life-expired switchgear. The cost of the

automation system was estimated to be less than this amount. Distribution automation was the economically attractive choice in this case.

This amounts to a different philosophy of operation. In essence, a trade-off is made between reducing the outage time by means of automation, and increasing the number of customers affected because of limitations of the switchgear.

Once the possibility of a different way of operating the system is accepted, other opportunities will be perceived. In the paper by Black *et al.*, the possibility of more complex feeder configurations is mentioned. In the typical distribution system in the United States, single-phase switching might have some appeal. Few loads on the typical overhead 12-kV system are three-phase loads. Single-phase switching would require a much greater knowledge of the system than is presently available, but would lead to increased reliability of supply with the present hardware. Presumably, less costly hardware could be used, and the reliability maintained at its present value for less cost.

This seems to be an area that holds considerable promise.

5. CONCLUSIONS

As a prelude to technical work on distribution automation, we investigated the impediments to the widespread implementation of the technology. We found that there were three problems:

First, the economics of distribution automation are ambiguous. While some of the proponents of distribution automation have made statements to the effect that the functions would pay for themselves in a very short time, hard economic analyses supporting this are few and far between.

Second, there are hidden costs to the implementation of distribution automation. These hidden costs, in the form of the system engineering required to be performed by the utility, added to the uncertainty of the overall economic picture. The utility contemplating distribution automation knows that it has to assemble its own system from components purchased from a number of vendors. Considerable resources have to be expended to make components operate successfully together.

Finally, while some distribution automation functions did not require a great deal of communications, we found that others required a better communication system than was currently available. Consequently, even if the economic impediments to the implementation of distribution automation could be removed, there would remain the technical impediment that general purpose automation was ruled out by the inadequacy of communications.

Our technical work in 1988 has therefore aimed at developing a communication system capable of supporting all the functions of distribution automation, and doing so at minimum cost. Cost is an essential factor in the design of a communication system for distribution automation, if it is not to bias the economic situation further against implementation.

The communications system has to be able to reach all parts of the distribution network, and must be tapped in dozens, perhaps hundreds, of places. The data rate was found in our analysis to be moderate by the standards of modern communications technology, and easily achieved with fiber optics.

We showed that a fiber optic solution to the communication problem can be implemented for a cost that compares with the conventional alternatives for a single function. Our proposed solution shows clear economic advantages as further functions are added. We feel that the ability to add further functions to a distribution automation system at lower incremental costs is essential if market development is to proceed.

Now that a communications backbone for distribution system control is available at a reasonable cost, it is to be hoped that suitable hardware and application software for distribution automation can be made available. Our future endeavors will be aimed at solving the medium access and routing control problems of the interconnected ring configuration of a fiber optics communication system, and at developing other sensors that can aid in the low cost acquisition of data.

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APPENDIX A: THE LINEAR COUPLER

The linear coupler, like the current transformer, is a device whose functioning is based on the magnetic flux of a current-carrying conductor. Typically, the sensing coil is wound over a toroid of non-magnetic material. The total flux Φ linked by the coil is

$$\Phi = \oint_c \int_A n(\mathbf{B} \cdot d\mathbf{A}) dl \quad (\text{A-1})$$

where n is the number of turns per unit length, \mathbf{B} is the magnetic flux density, A is the area element of the winding and dl is an element of length along the coil. The first integration is over the contour c of the toroid; the second is over the area of the winding.

In a well-made coupler, A is constant and the areas $d\mathbf{A}$ are normal to the toroid. Equation (A-1) is thereby simplified because $\int d\mathbf{A}$ is simply A . In addition, the sensor winding is uniform, so that n is constant. If it is assumed that the coil is small, so that the field is uniform across it, Equation (A-1) then becomes

$$\Phi = nA \oint_c \bar{\mathbf{B}} \cdot d\mathbf{l} \quad (\text{A-2})$$

Substituting $\mathbf{B} = \mu\mathbf{H}$ into equation (A-2) shows that the device implements the line integral of the magnetic field over a closed path to find the current enclosed by that path:

$$\oint \mathbf{H} \cdot d\mathbf{l} = I \quad (\text{A-3})$$

In other words, the flux linked by the linear coupler is given by $\Phi = \mu nAI$. Clearly, μ , n , and A are each constant, so that the flux is simply proportional to the primary current.

If we visualize the coil as being centered on the primary, the field seen by the secondary coil is uniform, with no azimuthal variation. (This configuration is not essential to the proper functioning of the device, it merely simplifies the mathematics. The linear coupler is accurate wherever the primary is located, provided the earlier assumptions of uniform construction and small cross-section are valid.) Equation (A-2) shows that the flux Φ is thus given by $\Phi = nIA\mu H$, where l is the length of the contour, ie, the circumference of the toroid. The product nl is conveniently written as N , the total number of turns.

The induced emf e in the secondary winding is given by

$$e = \frac{-d\Phi}{dt} \quad (\text{A-4})$$

so that the output of the coupler becomes

$$e = -\mu NA \frac{dI}{dt} \quad (\text{A-5})$$

Since the usual application of a linear coupler requires a knowledge of the primary current, rather than its derivative, the need for an integrator is clear. For sine-wave excitation, Equation (A-4) can be rewritten as the familiar transformer equation:

$$E = 4.44 B^{\wedge} A f N \tag{A-6}$$

where E is the rms output voltage, B^{\wedge} is the crest value of the flux density, and f the frequency. In the case of a CT, we would use Equation (A-6) to find the minimum cross section required for the core material chosen (ie, cold-rolled, stalloy, mu-metal etc.) not to saturate (hence the use of crest value for flux density) for a given burden. In the case of the LC, we can instead find the output voltage.

It is important to ensure that the single turn of the toroid itself links no flux. In the CT, the magnetic core ensures that the winding sees only flux due to an enclosed primary; without this core, the output can include a voltage induced by an adjacent, external current. The effect is reduced by using a large number of secondary turns, by completing the winding with a return conductor inside the coil, by winding the coil in two layers so that the winding ends at the same place it started, or by enclosing the coupler in an electrostatic shield that essentially short-circuits the single turn of the toroid without shorting the winding.