COMPUTER-BASED ANALYTIC METHODS USEFUL IN CONSIDERATION OF THE RATEMAKING STANDARDS OF PURPA

prepared by

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FOREWORD

This report was prepared by The National Regulatory Research Institute (NRRI) under Contract No. EC-77-C-01-8683 with the U. S. Department of Energy (DOE), Economic Regulatory Administration, Division of Regulatory Assistance. The opinions expressed herein are solely those of the authors and do not reflect the opinions nor the policies of either the NRRI or the DOE.

The NRRI is making this report available to those concerned with state utility regulatory issues since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with utility regulation.

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I. INTRODUCTION

Title I of the Public Utility Regulatory Policies Act[1] of 1978 (PURPA) has established a number of electric utility ratemaking standards which must be considered for adoption by each state's regulatory authority. Since the fair consideration of these standards requires the collection, organization, and manipulation of quantities of numerical data, it is appropriate to examine in detail the computer-based programs which can systematize the processing of such data. It is not the objective here either to discuss the relative merits of the various accounting methodologies or to examine in detail the provisions of PURPA, both of which tasks have been accomplished in part by the voluminous Electric Utility Rate Design Study conducted by EPRI[2]. Described in this report are the data manipulations required by PURPA which are amenable to computerization.

II. IDENTIFICATION OF ANALYTICAL METHODS IMPLIED BY PURPA STANDARDS

It is advantageous from an heuristic approach to review each of the ratemaking standards for the sake of identifying the analytic methods required by an objective consideration of adopting that standard. Since each method identified may be pertinent to several standards, detailed discussion of methods is withheld from this section.

1) <u>Cost of Service</u>: The electric rates for a class of consumers should have as their basis the cost of service to that class. This cost should show a functional dependency upon demand, energy, and customer levels. Because the demand and energy components generally have a strong

variability with time-of-week and time-of-year, the costing method should identify cost differences incurred by daily and seasonal use. Note that the demand and energy variables may be viewed collectively as the exhaustive cause of daily and seasonal cost variations; hence, the mention of daily and seasonal cost differences serves only to further define the level of detail required in the cost-component functions: they should be explicitly functions of time, at least to the level of generic day (e.g., winter holiday, summer weekday, spring/autumn weekend). Thus for each consumer class, it is necessary to have the hourly load curves as distinguished by season and type of day. Furthermore, the costing method should consider the costs of additional peaking capacity and base-load generation incurred in meeting the class demands. This implies that the costing should include not only historical but also projected data.

To perform a projection of the demand, energy and customer levels requires a Load Forecasting package that includes demographic and economic data for the region. The demand and energy projections should be maintained by class of consumer and voltage level so that class-specific rates can be evaluated throughout the projected years.

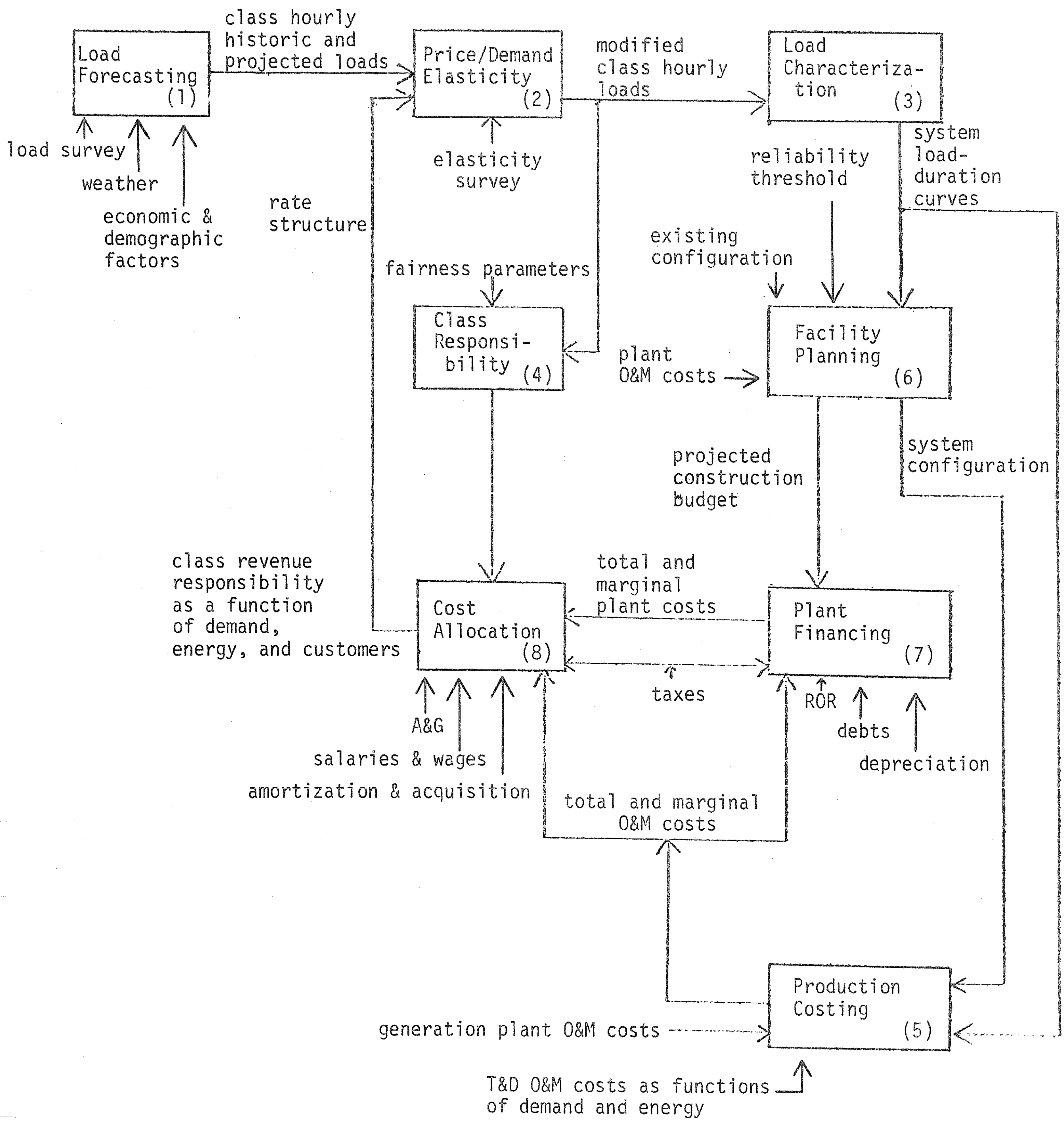
The distribution of accounting costs to the demand, energy, and customer categories requires a Cost Allocation package which is capable of either an embedded-cost allocation or a marginal-cost calculation. In support of this, a Load Characterization package is needed to convert the hourly load curves to load-duration curves appropriate to an aggregate-time (as opposed to real-time) simulation methodology; a Production

Costing package is needed to relate the generation operations-and-maintenance expenses to the historic and projected demand and energy functions; a Class Responsibility package is needed to determine the relative responsibility of each consumer class for the existence and construction of physical plant; a Plant Financing package is needed to compute the cost of plant additions in terms of revenue requirements per unit of load increase; and a Facility Planning package is needed to project generation, transmission, and distribution plant additions as a result of retirements and load growth. To convert the cost-function output of the Cost Allocation package to a tariff is a straightforward process of apportionment of the class cost-functions among the billed members of each class. The flow of information among processing packages is shown in Figure 1.

2) Declining Block Rates: The energy component of a rate for a consumer class should decrease with energy consumption no faster than do the energy-related costs. Thus declining block rates may be retained or imposed to the extent that the energy-related marginal costs for a class decrease with the consumption of that class.

This standard is seen not as a distinct addition to the ratemaking formula, but as a clarifying restriction upon the primary standard of service cost. No analytic methods other than those identified above will be needed to weigh the equitability of rates with declining energy-block coefficients.

FIGURE 1: INFORMATION FLOW DIAGRAM



3) Time of Day Rates: The rates for each consumer class should vary with time-of-day to reflect corresponding variations in the cost of service. However, if for any consumer class the long-term benefits to its members and to the utility are outweighed by additional metering and associated costs, the standard is nullified for that class.

In considering this standard, a stream of expenses due to meter installation and reading is to be compared with a stream of prospective savings due to reduced operating and maintenance costs and reduced or delayed capital expenditures for generating, transmission, and distribution plant. For a first-order analysis, the prospective operations and maintenance savings may be simplified to fuel savings. In either case, it is clear that the load curves used in the Production Costing package must carry detail at least to the hourly level, and must be subject to alteration by the price elasticity of demand. A routine net-present-value calculation is required to bring the elements in the two cash-flow streams into a single numeric pair for the long-run cost/benefit analysis.

Thus, in addition to a Plant Financing package for evaluation of plant capacity savings, and to the two costing packages, a Price/Demand Elasticity package is required to estimate the feedback effect of the proposed time-of-day rates upon the load curve of each class. This would logically be placed in series with the load-curve output from the Load Forecasting package, as shown in Figure 1.

4) Seasonal Rates: The rates for service to each class should vary with the seasonally-incurred costs in providing that service. Since the seasons may be defined to change at roughly the same time as the meters are read, very little additional metering and meter-reading expense is anticipated, and cost-justification is not explicitly required.

If seasonal (as opposed to annual) accounting data were available for all components of each class cost function, then this standard would require merely a seasonal iteration of the costing and allocation process outlined for the first standard. More likely, however, the seasonally-differentiated load-curve data must be analyzed by the Production Costing and Class Responsibility packages to determine seasonally-appropriate factors for allocation of the annual accounting data to each season defined in the tariff. This requires only a slight complication to be added to the Cost Allocation package.

5) Interruptible Rates: Rates for interruptible service should be offered to industrial and commercial consumers. Such rates should reflect the reduced cost of providing interruptible service compared with continuous service.

Since the purpose of such rates is the reduction of expenses due to a leveling of the system load curve, this standard should be considered using the same analytic methods as the time-of-day rates standard. The

possibility of defining the interruptible-service period as inclusive of emergency situations outside the normal time period of system peaks, offers the utility system a load-management advantage over that provided by the diversified response to time-of-day rates: the interruptible load is predictably responsive to peak-load-pricing whenever the peak (as defined by the load interrupter) occurs, independent of prescribed hours. Hence the interruptible consumer's cost of service should show a greater peak/base differential than a comparable consumer whose peak-load signals come only by the clock. In the case of interruptible consumers, the diversification of response comes in the acceptance or rejection of the price discount offered for reduced quality of service; it is not expected that all offers would be accepted. Hence the Price/Demand Elasticity package must be capable of estimating the response to the discount offer.

6) Load Management Techniques: Those techniques reliable and effective in reducing demands upon system capacity should be offered to consumer classes to the extent that they provide an expected savings to the utility (and thence to the contributory classes) in long-run costs.

Each such technique under consideration is expected to entail some capital outlay for energy storage or load-switching devices, in addition to ongoing expenses for operations and maintenance. The benefits are expected in the areas of reduced expenses for operations (specifically, fuel) and maintenance. Depending on the location of the energy-storage

device (compare, e.g., residential water tanks with a pumped-storage reservoir), the fair evaluation of each technique's cost-efficacy may involve the consideration of capital plant outside the utility company proper in the stream of cash flows pertinent to the long-run estimation of savings. To fit the framework of Figure 1, such exogenous costs would analytically be considered in aggregate as an endogenous cost borne by the utility exclusively for the sake of that consumer class accepting the load-management technique. The consideration of each diurnal technique requires, therefore, the same methods of analysis as did time-of-day rates; consideration of longer-term (e.g., annual cycle) energy storage techniques requires these same methods applied to both daily and appropriately longer-term capacity reductions. For example, a storage technique capable of smoothing cyclic load variations over a period of one week should be considered beneficial in impacting not only the weekday load-factor but also that for the entire week.

Although the next two standards are not pertinent to ratemaking, they are included here for the sake of orderly discussion.

7) <u>Master Metering</u>: The use of master meters in new buildings is restricted to those buildings for which the long-run savings to its consumers due to reduced consumer-related costs and meter expenses is greater than the savings under the alternative unit-metering due to individual price incentives to minimize consumption.

To execute the determinations required by this standard, the Price/Demand Elasticity package must be used to estimate the reduction in hourly demand by a group of consumer units when each is given an opportunity to save by curtailing its consumption, over the demand by that group having a single shared bill. The package should be capable of predicting load shifts based on input data on the statistical behavior of consumers in group-pricing situations. The alternative sets of load data would be processed in separate calculations of the expected annual bills using existing rates appropriate to each class. The net present worth of these billed differences (which include customer-costs), less the expense of meter purchase and installation, will determine the cost-efficacy of separate metering.

8) Automatic Adjustment Clauses: Each automatic fuel-cost-recovery clause should provide incentives for economic purchase and use of fuel and electric energy.

To execute the provisions of this standard, it is expected that a fuel-adjustment-clause monitoring (FAC Monitor) package would be used to periodically audit the performance of each utility, alone and in comparison with others, in the areas of economic purchase of fuel, thermal efficiency of generating plant, and economic purchase of power from a pool or network grid. A state regulatory authority may arguably insist, however, that its adjustment clause provides the mandatory incentives without performing any such audit of performance.

Inasmuch as the consideration of adoption of Lifeline Rates or the remaining standards of Section 113 does not require cost-justification by the provisions of Title I, no evaluation of numeric data is apparently needed. These matters will be decided most likely on the basis of legal and political ramifications rather than strict economics. Of course the design of various lifeline rates may require particular data collection and manipulation.

III. DATA MANIPULATIONS PERFORMED BY ANALYTICAL METHODS IDENTIFIED

For each of the analytic methods required by consideration of adoption of, or by implementation of, the standards reviewed above, a generic description is given of the input and output data and the algorithms used. For details specific to an existing computer-based model, the reader is directed to the documents referenced in section IV.

1) Load Forecasting: Intended to project hourly load curves by consumer class and by season, for typical and peak days for ten years, this package requires as input: historic load data in the same detail; temperature data for normalization of weather-sensitive components; and sufficient area-specific demographic and economic data to project industrial load, commercial load, number of residences and their appliance mix. For each group of consumer classes having distinct historic load characteristics, the load is broken into base and temperature-sensitive components. Using data on that group's installed

heating and air-cooling capacity, regression techniques are used to determine coefficients of peak-demand and energy change with temperature. Consideration of both saturation of installed air-cooling equipment and mandatory restrictions of operating thresholds should be made before extrapolating the weather-sensitive components. Given the probabilistic nature of future weather, account is taken of a range of probably extrapolations within a confidence band. Using the demographic and economic data, regressions are performed on historic base-load data, and the appropriate extrapolations are performed. At this point, daily peak-demand and energy has been projected by class and season for weekdays and weekends. To project the hourly data, correction factors relating increases in hourly consumption to daily energy are computed by correlating historic data for comparable days[3]. Aggregation of projections across consumer classes yields the system load.

Virtually all the output of the Load Forecasting package is duplicated by the utility-supplied data submitted in conformance with FERC regulations[4], with the exception of projected class hourly loads, which may be useful in analysis of time-of-day pricing and load management techniques. It is anticipated, however, that state regulatory authorities will pursue an independent projection of the verifiable historic data, hence will employ their own forecasting methodology.

2) Price/Demand Elasticity: Three sets of survey data must be provided to this package. The first will consist of hourly load data

from a sample of consumers under experimental time-of-day rates and comparable data from a control group, as in the Wisconsin Electricity Pricing Experiment[5]. These data allow calculation of the elasticity of diversified substitution of off-peak energy for peak energy, as a function of the duration of the peak period and of the price ratio. The data for evaluation of interruptible rates is of a similar form, but can be obtained by a survey of willingness to subscribe at the various discount rates, without any time-consuming experiment. The third set consists of data comparing consumption of master-metered units with that of separately metered units under similar circumstances of tenants' income and appliance stock; such data may be available by scrutiny of historic bills.

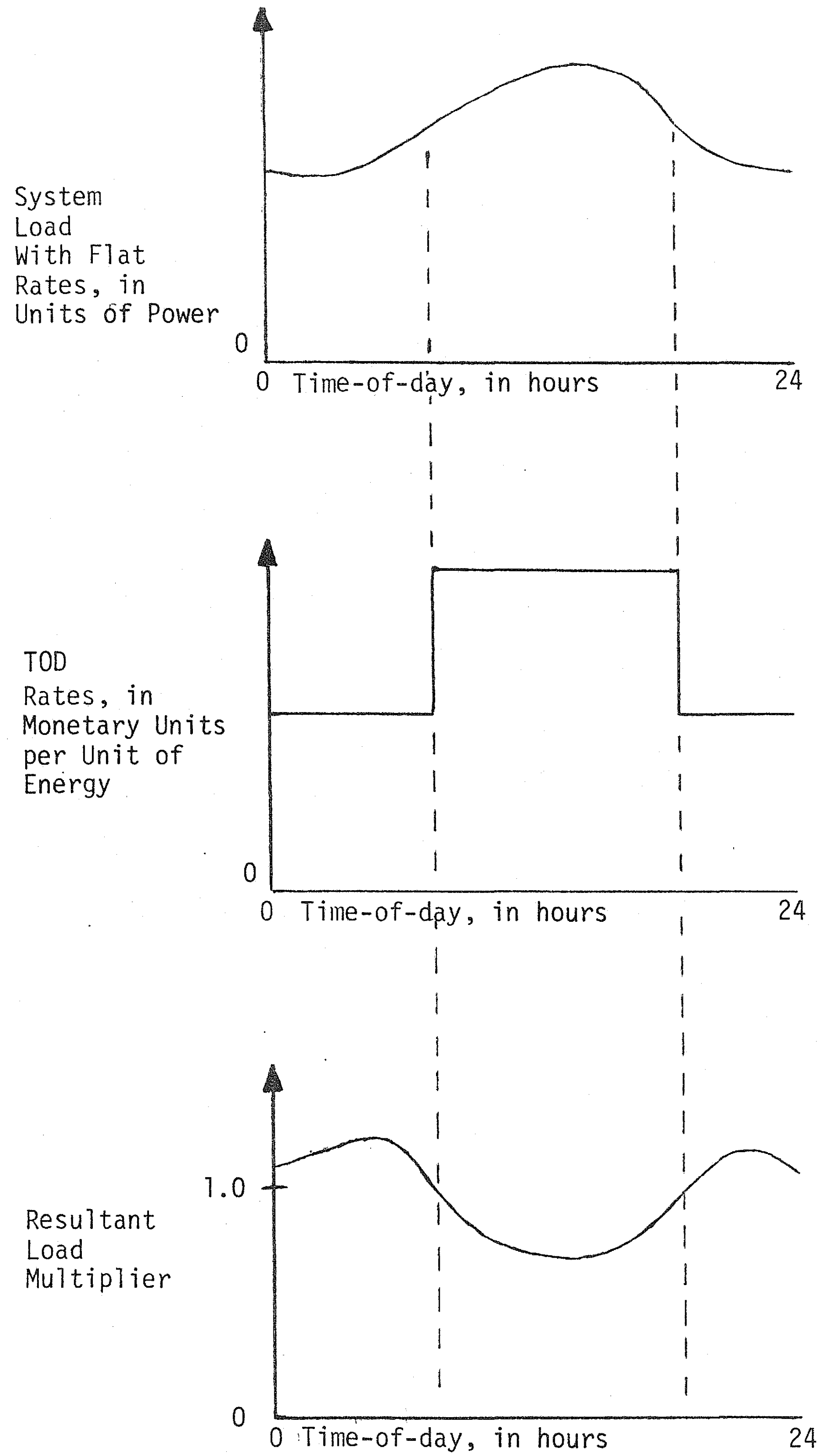
In each case, the derived elasticity function will be used as a control parameter for each iteration of the package, which merely accepts the unmodified historic or projected class load curve as an input vector, multiplies each element by the load ratio for that hour appropriate to the rate-policy under investigation, and produces an output vector of modified hourly loads. In the case of time-of-day rates, the multiplier is expected to be more complex than a two-valued diagonal matrix. In general, the hourly loads under time-of-day rates will be a function also of proximity to the price-switching times. These effects are taken into account by employing a matrix of multiplier elements; for modification of a vector of 24 hourly loads for, e.g., the seasonal peak day for one class, the matrix need be no larger than 24 square.

The general shape of the proximity-sensitive multiplier is illustrated by Figure 2.

The package will be used repeatedly to generate a family of hypothetical load curves, one for each proposed combination of price differential and peak-period duration. Even if greater complexity than two-valued rates is contemplated (e.g., shoulder-periods) the approach outlined is sufficient. The package can thus be used, in conjunction with the packages downstream from it in the data flow of Figure 1, to define the rate periods and to estimate their net efficiency in reducing costs.

3) Load Characterization: Intended to reduce hourly class and system load data to the form of load-duration curves and graphs, this package requires as input the 60-minute-integrated demand data indexed by hour of day, day of week, day of month, month, and year (as, e.g., supplied to the Edison Electric Institute). Under the direction of input parameters defining the period and day-types of interest, the package scans the database for qualifying days, counting frequency of occurrence at indexed discrete load-levels. The resultant load-frequency array is transformed to a load-duration array by simple accumulation of the frequencies (hours) counted. An auxiliary graphing routine may be used to display the load-duration curve or the hourly average and peak loads for specific days of the week. The latter, while not of analytic value to downstream packages, may be found useful in preliminary stages of defining peak-load-pricing periods. The load-

FIGURE 2: ILLUSTRATION OF DISPERSION EFFECTS OF TIME-DIFFERENTIATED RATES



duration curve, or its normalized version, the load-probability curve, provides fundamental input to the Facility Planning and Production Costing packages.

4) Class Responsibility: The fixed and operating costs of plant fuel, maintenance, ownership, new construction, taxes, etc., must be fairly distributed across the consumer classes. The desired output is thus a set of three vectors (one each for demand, energy, and customer categories) of responsibility by class, whose elements sum to unity in each case. In the absence of justifiable bias, it is expected that the cost of service standard would imply that elements in the energy vector be proportional to class energy consumption, and that those in the customer vector be proportional to number of customers in each class. It may not, however, be difficult to justify higher-than-average costs for classes of large-usage or few customers.

The bulk of the processing work is performed in determination of the demand vector. This requires judgmental input of parameters defining a) whether peaks shall be counted at hours coincident with system peaks, or simply at class peaks; b) the number of peaks to be counted to obtain a statistically valid picture of relative demand; c) the fraction of the summer and winter peaks considered the threshold for high-energy consumption; and d) the relative weighting factors associated with the peak responsibility, summer high-energy responsibility, and winter high-energy responsibility. Implicit in the package methodology is the decision to consider class peaks' significance on

the basis of probability of contribution to system peak, or on the basis of probability of loss-of-load (LOLP), which probabilities may differ considerably dependent upon the maintenance schedule for generation plants. The package scans the hourly-load data over the seasons and years of interest, accumulating peak demand, LOLP, and high-energy data for qualifying hours. The ratio of each class sum to the system total, combined across peak and high-energy categories using the weighting factors, yields the demand-responsibility vector.

5) Production Costing: The operations and maintenance costs for generation of electricity are to be expressed, by FERC accounts, as functions of the system load. As input, the package requires the system load-duration curve, the set of plant operating parameters (heat rates, fuel costs, block-capacities, forced-outage rates), and the loading order (including effects of scheduled maintenance). Each unit's block-loading under probabilistic simulation of forced outages contributes an increment of energy to the system as it is brought on-line. Multiplying the energy increment by the fuel cost yields the system fuel-cost increment. If non-fuel O&M production expenses are assumed to have some simple relationship, for each type (e.g., hydro, nuclear, gas turbine) of unit, to the energy produced by that unit, then stepping through the loading order allows the production cost to be accumulated for the particular load-duration curve used as input. By iteratively calculating the total cost for a set of incrementally larger load-duration curves, the production cost is determined as a function of demand. Numerical differentiation of this continuous function yields

the marginal energy cost as a function of demand (system integrated hourly load).

6) Facility Planning: Changes in the system load curves are reflected in changes in the optimal expansion plan for generation, transmission, and distribution plant. This package requires as input the seasonal system load-duration curve (in array form), the set of operating parameters for existing and anticipated plant-types, the configuration of the existing plant mix, and the reliability threshold for consideration of future configurations. The comparative simplicity and short lead-times of transmission-and-distribution (T&D) planning have concentrated packaged efforts mainly on generation-facility planning; effects of load-management and peak-pricing upon T&D expansion plans should not be ignored, however. Some sort of marginal (i.e., correct for small changes to the existing T&D configuration) relationship must be drawn between a hypothetical increase in demand and the expected addition of T&D plant (see Reference 4, paragraphs 290.304 and 290.305).

The generation-planning section uses an optimization approach to examine the costs of pursuing each of the feasible branches of a multi-step (long-term) expansion plan; the lowest-cost (up to the planning horizon) sequence of configurations is defined as optimal. Note that the type of load-growth (in the base, cycling, or peaker regions), as well as the existing plant mix, determine to a large extent the type of plants needed to supply marginal growth; one should not assume that the marginal cost of increased generation capacity is that of adding peaking units alone.

7) <u>Plant Financing</u>: Given a schedule of plant retirements and new construction, this package computes revenue requirements to satisfy parametric constraints (e.g., return on ratebase or common equity). Supporting data required are historic debt and preferred stock obligations, federal and local tax rates, capitalization and dividend-payout ratios, value and depreciation rates of plant by categories, and AFDC rates and trends. From the Production Costing package, data are needed on projected running costs categorized by operations, maintenance, fuel, and purchased power. Under the parametric constraints, the package projects annually to the planning horizon, issuing debt and stock as required to finance the new construction program. The marginal cost of plant capacity is obtained by tracking changes in revenue requirements due to changes in the construction plan. Since distinct types of plant (generation, transmission, and distribution) may be allocated differently to demand, energy, and customer categories, the output marginal cost should be maintained in disaggregate form by plant type.

Note that a relaxation of some of the non-linear constraints may permit the unitized marginal cost of plant to be approximately computed by considering only a few elements: book and tax depreciation rates, interest rate of debt, property taxes, insurance, income taxes and deferrals, investment tax credit, and the required rate of return[6]. Such simplifying approximations may prove useful in performing first-order estimates and in bounding the range of reasonable results from a more detailed model.

8) <u>Cost Allocation</u>: The system-wide annual cost of service is required to be fairly allocated to a ratemaking matrix having demand, energy, and customer components for each class of service distinguished by a separate rate. The FERC Uniform System of Accounts provides that all operations and maintenance accounts have their data functionalized by five categories: production, transmission, distribution, customers, and administrative and general. Other major expense accounts (depreciation, state excise tax, other taxes, net operating income, and amortization and acquisition expenses) are allocated to the five functional categories generally according to the distribution of net plant in service in those categories; the exceptions are payroll taxes (allocated proportionately to salaries and wages) and taxes other than excise, federal, property or payroll (assigned entirely to administrative and general).

Next, the sums in the five functional categories are allocated to demand, energy, and customer components. This may be accomplished by consideration of historical cost-incurrence and logical assignment either by individual accounts or by grouped accounts. For example, all depreciation and property taxes may reasonably be assigned to the demand component; steam plant maintenance, which may be assigned to a particular range of system loads, is reasonably allocated to demand and energy components using the same load-specific criteria as discussed under Class Responsibility.

Since Section 133 of PURPA requires cost-of-service data pertinent to consideration of its ratemaking standards to be submitted separately by components of demand, energy, and customers, the above allocation steps will be required only for those accounts not pertinent to the standards. They are still necessary, however, to express the full cost of service in component terms, so that the hypothetical rates derived therefrom will be comparable to existing tariffs and will fully recover the required revenues.

In contrast to the allocation of embedded costs described above, a marginal-cost approach would express expenses in each of the functional categories (production, transmission, distribution, customers, and administrative and general) not as fixed fractions allocable to the three components, but as a generalized function of these components as arguments. Note that if this function were linear in each argument, it would degenerate to imply a 5 x 3 matrix of allocation coefficients, as in the embedded-cost approach. Hence, the calculation of marginal costs requires the development of five nonlinear cost functions which, for the purposes of numerical computations, are combined and expressed on a set of discrete three-dimensional points covering the range of component-space over which the utility operates. Assuming that this aggregate function is linearly separable into demand, energy, and customer components, its three partial derivatives at any point in the component-space are the short-run marginal cost components. Applications to multi-period pricing have been discussed in the literature [7].

The demand, energy, and customer components, as submitted or derived, must be distributed across the rate-differentiated classes by using the class-responsibility vectors. The resultant array or rate-making determinant is used to close the feedback loop around the information-flow model; a modified rate structure acts as parametric control of the Price/Demand Elasticity package, causing effects on the system load curves, which drive each of the other packages (except Load Forecasting) to a new state.

The portions of the model recommended for breaking the loop to investigate sensitivity to judgmental input are 1) the cost-allocation factors relating the functional categories to components; 2) the responsibility parameters defining those portions of load to be considered demand-related; and 3) the highly visible area of rate-structure design as a function of class components. In each case there is room for considerable latitude of considered opinion. Therefore a range of parametric values is appropriate for study in the process of considering each PURPA standard.

9) FAC Monitor: This package is considered separate from the others because its conclusions are not impacted by hypothetical changes in the system load characteristics; it covers only historical data on heat rates, fuel costs, and purchased power. It organizes the monthly data, making comparisons with the recent past to call attention to abnormal purchases or operating conditions. Computation of achieved

heat rates allows comparison with target values used in a program of incentives for improved fuel efficiency. Energy purchases from available pools are checked for economic advantage.

IV. EXTANT COMPUTERIZED PROGRAMS SUPPORTING THE ANALYTIC METHODS

A review of a compendium[8] of abstracts of publicly available computer programs has produced a number of candidates from which regulatory authorities may choose in implementing the analytic methods described. The analytic methods of the previous section which each program covers are presented in tabular form by Figure 3. Since familiarity with the detailed contents of each listed program is nearly impossible, the noted comments are necessarily brief, in most cases being derived from the abstract alone. Having selected the modules most likely to fill the needs of its state, the regulatory agency should refer to the contact agency for a more detailed description of program capabilities and limitations before requesting a source copy.

In organizing the acquisition and use of these programs, it is recommended that the Plant Financing and Cost Allocation modules be considered central in the sense of defining the form and quantity of data required from the other modules; these two should be chosen and developed first.

REFERENCES

1) "Public Utilities Regulatory Policies Act," Public Law 95-617, 16 USC 2601, November 9, 1978.

2) Reference Manual and Procedures for Implementing PURPA, Electric Utility Rate Design Study Volume #82, Electric Power Research Institute, March, 1979.

3) "Weather Sensitive Electric Demand and Energy Analysis," Ronald P. Thompson in IEEE Transactions on Power Apparatus and Systems Volume PAS-95 #1, January/February, 1976.

4) "Procedures Governing the Collection and Reporting of Information Associated With the Cost of Providing Electric Service," Federal Energy Regulatory Commission Docket #RM 79-6, June, 1979.

5) "Findings of Fact and Order Establishing Temporary Experimental Rates," Public Service Commission of Wisconsin Docket #6690-ER-5, February 18, 1977.

6) Costing for Peak Load Pricing: Topic 4 Results for Portland General Electric Company, Electric Utility Rate Design Study Volume #30, pp. 103 ff., Electric Power Research Institute, June, 1977.

7) "Peak Load Pricing with a Diverse Technology", Bell Journal of Economics, pp. 207-231, Spring 1976.

8) Task 2G Deliverable: Regulatory Computer Program Descriptions, National Regulatory Research Institute, June 20, 1978.

Figure 3: Supportive Computer Programs+

#	Program Name	Contact	Analytic Methods*	Comments
1	Short Term Load Forecast	Power Technologies	1	projects load for each day in a year
2	Electric Forecasting	Florida PSC	1	projects kwh load based on exponential and polynomial functions
3	Residential Energy Conservation Strategies	Oak Ridge National Laboratory	1,2	projects for 25 years residential energy impact of changes in economic and engineering conditions
4	Dynamic Model for Forecasting Demand	N. Carolina State University	1	projects for 12 years demand for a specific region in the Carolinas
5	PNW/West Group Load Estimate	Bonneville Power Admin.	1	estimates peak and average loads
6	Weather Normalization Studies	New York PSC	1	extrapolates normalized sales using multivariate regression
7	Load Weather Correlation	Power Technologies	1	develops correlation between historic weather and load
8	Load-Lambda	Temple, Barker & Sloane	3	generates load statistics for user-defined peak and base periods
9	System Load Data Analysis	Iowa State Commerce Commission	3	generates average weekday load-duration data from EEI input on monthly, seasonal, and annual basis
10	Industrial Load Patterns	Battelle Memorial Institute	3	provides perspective on industrial load patterns
11	Load Research System	Gilbert Associates	3	produces a time-structured load research database
12	Load Data Analysis (FRED)	NRRI	3	produces load-duration data from EEI input for a specified period

+Sources are listed in Figure 4.

* Key to Analytic Methods:

1 Load Forecasting
2 Price/Demand Elasticity
3 Load Characterization
4 Class Responsibility
5 Production Costing
6 Facility Planning
7 Plant Financing
8 Cost Allocation
9 Fuel Adjustment Clause Monitor

Figure 3: Supportive Computer Programs (continued)

#	Program Name	Contact	Analytic Methods*	Comments
13	Marginal Cost & Pricing of Electricity	Planning & Conservation Foundation		methods used are undisclosed
14	Time-of-Day Pricing	Ohio PUC	4	computes monthly bill based on adjusted EEI input and a hypothetical tariff
15	Neoclassical Peak-Load Pricing	Bell Telephone Laboratories	4	assigns capacity costs to users in all time periods
16	Rate Structure Time of Use, Cost Allocation	FERC	4	assigns revenue responsibility across customer classes
17	Cost of Service	New York PSC	4,8	distributes rate increases across customer classes
18	Cost Allocation	Gilbert Associates	4,5,7,8	generates a complete cost-of-service study
19	Future Test Year, Cost of Service	FERC	7,8	projects cost of service and revenue requirement based on past sales and O&M, and on plant forecasts
20	Marginal Cost of Electricity	Wisconsin Office of Planning & Energy		methods used are undisclosed
21	Marginal Cost	NRRI	5,7	computes marginal capacity and energy costs for generation and T&D using method of Cicchetti, Gillen, and Smolinsky
22	Economic Merit Order and Marginal Costs for Fossil and Nuclear Units	Oak Ridge National Laboratory	5	
23	Production Cost Simulation	Virginia State Corporation Commission	5	dispatches units according to load-duration and variable 3-block loading

Figure 3: Supportive Computer Programs (continued)

#	Program Name	Contact	Analytic Methods*	Comments
24	Generation Reliability and System Expansion	Power Technologies	6	uses load-frequency/duraction input, computes LOLP and frequency of reserve-margin states
25	Load Resource Comparison	Bonneville Power Administration	6	evaluates present worth of a 20-year plan of hydro and thermal plant additions, considers reserve requirements
26	Optimal Expansion Planning	Systems Control	6	incorporates model for intermittent generation sources
27	Long-Term Generation Expansion Planning	Carnegie-Mellon University	6	considers future uncertainty, mix of nuclear, fossil, hydro, and pumped-storage units
28	OPTGEN	Stone and Webster Engineering	6	selects most economical generation expansion plan
29	WASP	Oak Ridge National Laboratory	6	uses dynamic programming to find the optimal expansion plan
30	Optimal Generation Planning	Power Technologies	6	develops sets of expansion patterns in stages
31	Capacity Planning	Power Technologies	6	considers 2-block loading, mixed plant types, maintenance scheduling for level risk, LOLP, and load frequency/duration
32	GEM	Massachusetts Institute of Technology	6	present worth of costs of expansion patterns are minimized subject to constraints on demand, pollution, reliability, fuel and site availability
33	OGP	General Electric	6	long-range optimized generation planning considering alternative load-growth scenarios
34	TNET	General Electric	6	long-range transmission planning considering alternatives in load-growth, generation plans, and network designs

Figure 3: Supportive Computer Programs (continued)

#	Program Name	Contact	Analytic Methods*	Comments
35	Optimization Models for Nuclear & Fossil Plant Planning	Oak Ridge National	6	
36	Long Range Generation Planning	United Engineers and Constructors	6	identifies cost of production plans, including carrying costs
37	Generation Planning (LOADS, PROBS, HPROD, ICOST)	General Electric	3,5,6	produces operating costs of generation and revenue requirements of alternative expansion plans
38	GENCAP	U. of Wisconsin Institute for Environmental Studies	1,3,6	computes yearly costs of each generation expansion plan investigated after forecasting load-durations
39	Capacity Optimization #1	N. Carolina Utilities Commission	6	creates an optimal schedule of capacity additions considering fuel and capital costs
40	None	Jerome Karaganis EPRI	6	considers reserve margins, outages, fixed and variable costs, environmental costs
41	Corporate Model	Power Technologies	5,6	submodels provide input to Financial Model below
42	Financial Model	Power Technologies	7	annual and monthly models consider tax and regulatory constraints
43	FSP	General Electric	7	financial simulation considers planning scenarios, rate changes, earnings, new financing, cash flow
44	Financial Forecast for REA Borrowers	Rural Electrification Administration	7	produces statements of operations and ratios, balance sheet, sources and uses of funds; models terms of REA loans
45	Financial Statement Projections	New York PSC	7	evaluates financial structure of power companies or pools

Figure 3: Supportive Computer Programs (continued)

#	Program Name	Contact	Analytic Methods*	Comments
46	RAm	Temple, Barker & Sloane NRRI	7	projects financial conditions for a given capital budget and historic O&M costs, subject to regulatory constraints, producing balance sheet, sources and uses of funds, and income statements
47	Utility Financial Model	Michigan PSC	7	rate-case oriented system produces rate base, rate of return, revenue deficiency, sources and uses of funds, and income statements
48	REM	Joskow D. Baughman Massachusetts Institute of Technology	1,7	regional model considers supply, demand, and financing under regulatory constraints
49	Corporate Modeling & Financial Planning	Corporation Commission of Oklahoma	7	considers alternative growth-patterns, expansion plans, and rates.
50	Electric Utility Corporate Model	General Electric	7	projects tax and cash reports, balance sheet and income statements based on regulation of earnings on rate base or common equity
51	Fuel Adjustment, Fuel Cost	FERC	9	considers adjustments due to changes in fuel costs, generation mix, and heat rates
52	Fuel Adjustment Data	Pennsylvania PUC	9	stores and prints data on fuel type and source
53	Fuel Adjustment Clause	Ohio PUC	9	verifies and reports fuel purchase and use data, flagging areas of conflict with regulations

FIGURE 4: SOURCES OF COMPUTER PROGRAMS

Battelle Memorial Institute
505 King Avenue
Columbus OH 43201

Bell Telephone Laboratories, Inc.
600 Mountain Avenue
Murray Hill NJ 07974

Bonneville Power Administration
P.O. Box 3621
Portland OR 97208

Carnegie-Mellon University
Frew Avenue & Margaret Morrison
Pittsburgh PA 15213

Corporation Commission of Oklahoma
308 Jim Thorpe Building
Oklahoma City OK 73105

Electric Power Research Institute
Energy Analysis Department
P.O. Box 10412
Palo Alto CA 94303

Federal Energy Regulatory Commission
825 North Capitol Street NE
Washington DC 20426

Florida Public Service Commission
101 East Gaines Street
Tallahassee FL 32301

Gilbert Associates, Inc.
P.O. Box 1498
Reading PA 19603

Iowa State Commerce Commission
Fourth and Walnut Streets
Des Moines IA 50319

Massachusetts Institute of Technology
77 Massachusetts Avenue
Cambridge MA 02139

Michigan Public Service Commission
P.O. Box 30221
Lansing MI 48909

National Regulatory Research Institute
2130 Neil Avenue
Columbus OH 43210

New York Public Service Commission
Agency Building #3
Empire State Plaza
Albany NY 12223

North Carolina State University
2205 Hillsboro
Raleigh NC 27607

Oak Ridge National Laboratory
P.O. Box 117
Oak Ridge TN 37830

Ohio Public Utilities Commission
180 East Broad Street
Columbus OH 43215

Pennsylvania Public Utilities
Commission
P.O. Box 3265
Harrisburg PA 17120

Planning & Conservation Foundation
c/o National Technical Information
Center
5285 Port Royal
Springfield VA 22150

Power Technologies, Inc.
P.O. Box 1058
Schenectady NY 12301

FIGURE 4: SOURCES OF COMPUTER PROGRAMS
(Continued)

National Rural Electric Cooperative
Association
2000 Florida Avenue NW
Washington DC 20009

Stone and Webster Engineering Corporation
90 Broad Street
New York NY 10004

Systems Control Inc.
1801 Page Mill Road
Palo Alto CA 94304

Temple, Barker & Sloane, Inc.
33 Hayden Avenue
Lexington MA 02173

United Engineers & Constructors, Inc.
100 Summer Street
Boston MA 02110

University of Wisconsin Institute for
Environmental Studies
c/o National Technical Information Center
5285 Port Royal
Springfield VA 22150

Virginia State Corporation Commission
P.O. Box 1197
Richmond VA 23209

Wisconsin Office of Planning & Energy
P.O. Box 511
Madison WI 53701