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PRODCOST—An Electric Utility Generation Simulation Code

C. R. Hudson, II
T. M. Reynolds
G. R. Smolen

MASTER

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Prepared by
OAK RIDGE NATIONAL LABORATORY
Oak Ridge, Tennessee 37830
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PRODCOST — AN ELECTRIC UTILITY
GENERATION SIMULATION CODE

C. R. Hudson II
T. M. Reynolds
G. R. Smolen

ABSTRACT

The PRODCOST computer code simulates the operation of an electric utility generation system. Through a probabilistic simulation the expected energy production, fuel consumption, and cost of operation for each plant are determined. Total system fuel consumption, energy generation by type, total generation costs, as well as system loss of load probability and expected unserved energy are also calculated.

1. INTRODUCTION

PRODCOST was developed to probabilistically simulate the generation system of an electric utility. The PRODCOST code will calculate the expected operation of each unit in the system identifying the energy generation, the operating cost, and the fuel consumption. The code also aggregates this information into total system generation, cost, and fuel consumption by fuel type. System unserved energy and loss of load probability are also presented. This code does not take into account the transmission and distribution system of the utility. It assumes that there are no transmission limitations within the system. Finite energy exchanges with neighboring utilities can be modeled, however.

PRODCOST was originally developed in the early 1970's as a joint effort of ORNL and TVA. Some modifications were made as the code was used at ORNL in the 1970's. During the summer of 1980, substantial modifications were made to the code by the authors. Improved maintenance scheduling and loading order calculations as well as the ability to explicitly model external purchases and sales and unit deratings are among the enhancements present in the current version of PRODCOST.

This document discusses the methodology used in PRODCOST as well as the specific function of each routine in the code. An index of variable

names and their meaning is offered in Appendix A. User input instructions, an example, and a description of the output from the example are also presented.

2. PRODCOST METHODOLOGY

2.1. Probabilistic Simulation of Electric Utility Systems¹

The concept of using a probabilistic simulation for estimating the operating cost of generating plants within an electrical utility was first introduced in 1967.² In general, the probabilistic simulation technique develops the cost of operating a utility system over an extended period of time by forecasting the expected amount of energy to be generated by each plant. The basic model for this technique requires the following information: system load duration curve, loading order of units, generating unit characteristics, fuel costs, and energy supplied by energy-limited units such as pumped storage and conventional hydroelectric units. The major advantage of this technique is its capability to simulate the effects of random events such as unit forced outages.

A load duration curve, shown in Fig. 1, is frequently used to represent the system load over an extended period of time. As with a chronological hourly load curve, the area under the load duration curve represents the total system energy requirement; however, the chronological sequence of loads has been lost. In the load duration curve, the abscissa

Fig. 1. Typical load duration curve.

represents the number of hours during which the system load equals or exceeds the associated amount of power on the ordinate. By normalizing the time variable, the value at any point on the abscissa becomes the fraction of the entire period for which the load equals or exceeds the associated power. Carrying this logic a step further, the abscissa can be considered to represent the probability that a particular value of the system load will be equaled or exceeded.

It is more convenient in probabilistic simulation work to use the load duration curve with the ordinate and abscissa reversed (see Fig. 2). This form of the curve is called an "inverted" load duration curve. If all units were available for generation 100% of the time, the amount of energy generated by each unit could be determined by plotting each unit's capacity, in order of increasing cost of operation, on the inverted load duration curve as shown in Fig. 3. The energy for each unit would be

Fig. 2. Typical "inverted" load duration curve.

Fig. 3. Unit loading when all units are 100% available.

calculated by integrating the curve* between the proper limits:

$$E_i = T \int_{a_i}^{b_i} L(x) dx , \quad (1)$$

where

E_i = expected energy generation of i th unit;

T = time period represented by load duration curve;

$L(x)$ = inverted load duration curve;

a_i = cumulative capacity for units 1, 2, ..., $i-1$;

b_i = cumulative capacity for units 1, 2, ..., i .

Unfortunately, all generating units are subject to random outages, the occurrence and duration of which are unpredictable. In the simplest model for treating unit reliability, two possible states are defined for each unit. The unit is either available and capable of full power generation, or it is unavailable and unable to deliver any power. Associated with each state is a probability of the unit being in that state. Let p_i be the probability that unit i is available, and let q_i be the probability that the unit is not available. Since the unit must be in one of the two states,

$$p_i + q_i = 1.0 . \quad (2)$$

The probability q_i is normally referred to as the forced-outage rate. As an example, the amount of energy likely to be generated by Unit 1 in Fig. 3 can be calculated by multiplying the area under curve L by the probability that this unit will be available:

$$E_1 = p_1 T \int_{a_1}^{b_1} L(x) dx . \quad (3)$$

*PRODCOST uses a discrete representation of the continuous function $L(x)$. For ease of discussion, the continuous representation will be used.

The major difficulty encountered in using a load duration curve to estimate the unit loadings is that the position of operating units in relation to the load duration curve changes when any unit suffers a forced outage. The order in which the units are plotted in Fig. 4 shows how the system would be operated when Unit 1 is not available. Comparing Figs. 3 and 4, it is observed that all units have been shifted to the left by an amount equivalent to the capacity of Unit 1. It is important to note that a significant change has occurred in the expected generation of some of the units, particularly the units in the region of the maximum system load (Units 9-14).

Instead of considering two separate loading positions, an alternative and equivalent representation of an outage of Unit 1 would be to leave Unit 1 in its original position and shift the inverted load duration curve to the right by the capacity of Unit 1 (see Fig. 5). Let L represent the original inverted load duration curve and let L' be the shifted curve. From Fig. 5, it can be seen that

$$L'(x) = L(x - MW_1), \quad (4)$$

where

MW_1 = the capacity of Unit 1.

From this, the probability that Unit 2 would be loaded by curve L is p_1 , and the probability that Unit 2 would be loaded by curve L' is q_1 .

Fig. 4. Unit loading when Unit 1 is not available.

Fig. 5. Representation of equivalent load.

The expected generation of Unit 2 would be calculated by:

$$E_2 = p_2 T \left\{ \int_{a_2}^{b_2} [p_1 L(x) + q_1 L(x - MW_1)] dx \right\} . \quad (5)$$

The effect of forced outages can be combined with the system load in a single variable, the equivalent load. The equivalent load is defined as:

$$EL_{i-1} = L + O_i , \quad (6)$$

where

EL_{i-1} = equivalent load considering outages of units before Unit i in the loading order (Units 1, 2, ..., $i-1$);

L = system load duration curve;

O_i = additional operation required of unit i by outages of units prior to Unit i in the loading order (Units 1, 2, ..., $i-1$).

For Unit 2, the system load would be determined from the original inverted load duration curve (L) as:

$$L = L(x) .$$

The operation of Unit 2 caused by an outage of Unit 1 would be represented by the difference between curves $L(x - MW_1)$ and $L(x)$. The equivalent load curve for Unit 2 (EL_1) would be evaluated by multiplying the additional load by the probability of having to serve the additional load,

$$EL_1 = L(x) + q_1 [L(x - MW_1) - L(x)] ,$$

which, on substitution of Eq. (2), becomes:

$$EL_1 = p_1 L(x) + q_1 L(x - MW_1) . \quad (7)$$

Substituting Eq. (7) into Eq. (5) yields

$$E_2 = p_2 T \int_{a_2}^{b_2} EL_1(x) dx . \quad (8)$$

In a similar manner, the effects of outages in both Units 1 and 2 must be considered in order to evaluate the expected generation of Unit 3. In doing this, four different cases must be considered:

- (1) Units 1 and 2 both available, probability $p_1 p_2$.
- (2) Unit 1 available and Unit 2 unavailable, probability $p_1 q_2$.
- (3) Unit 1 unavailable and Unit 2 available, probability $q_1 p_2$.
- (4) Units 1 and 2 both unavailable, probability $q_1 q_2$.

For case 1, Unit 3 would be loaded according to the inverted load duration curve $L(x)$. For the remaining cases, it has been shown that an outage of a unit can be represented by shifting the load duration curve to the right by an amount equivalent to the capacity of the unit out of service.

Therefore, Unit 3 would be loaded for case 2 by curve $L(x - MW_2)$, for case 3 by $L(x - MW_1)$, and finally by $L(x - MW_1 - MW_2)$ for case 4.

Now the expected energy for Unit 3 would be:

$$E_3 = p_3 T \left[p_1 p_2 \int_a^b L(x) dx + p_1 q_2 \int_a^b L(x - MW_2) dx \right. \\ \left. + q_1 p_2 \int_a^b L(x - MW_1) dx + q_1 q_2 \int_a^b L(x - MW_1 - MW_2) dx \right] . \quad (9)$$

The first and third terms in Eq. (9) can be rewritten as:

$$p_2 \int_a^b [p_1 L(x) + q_1 L(x - MW_1)] dx . \quad (10)$$

Referring to Eq. (7) the term inside the brackets is seen to be simply the definition of the equivalent load curve (EL_1) incorporating an outage of Unit 1. Thus,

$$\begin{aligned} E_3 = p_3 T & \left[p_2 \int_a^b EL_1(x) dx + p_1 q_2 \int_a^b L(x - MW_2) dx \right. \\ & \left. + q_1 q_2 \int_a^b L(x - MW_1 - MW_2) dx \right] . \end{aligned} \quad (11)$$

Let $y = x - MW_2$; then, noting that $dx = dy$, the last two terms in Eq. (10) become:

$$q_2 \int_a^b [p_1 L(y) + q_1 L(y - MW_1)] dy .$$

Referring to Eq. (7), this is simply the equivalent load curve for y , $EL_1(y)$, when the outage of Unit 1 is incorporated. Therefore,

$$E_3 = p_3 T \left[p_2 \int_a^b EL_1(x) dx + q_2 \int_a^b EL_1(y) dy \right] .$$

Now, replacing y with $x - MW_2$ and rearranging Eq. (11) yields

$$E_3 = p_3 T \int_a^b [p_2 EL_1(x) + q_2 EL_1(x - MW_2)] dx . \quad (12)$$

Hence the energy to be generated by Unit 3 would be calculated from a new equivalent load curve which is formed by incorporating the effect of outages of Unit 2 into the original equivalent load curve:

$$E_3 = p_3 T \int_a^b EL_2(x) dx , \quad (13)$$

where

$$EL_2(x) = p_2 EL_1(x) + q_2 EL_1(x - MW_2). \quad (14)$$

An equivalent load curve can be generated to include forced outages of any number of units by successively applying Eq. (14). For successive units the equivalent load curve is:

$$EL_n(x) = p_n EL_{n-1}(x) + q_n EL_{n-1}(x - MW_n), \quad (15)$$

and the expected generation for each unit is:

$$E_n = p_n T \int_{a_n}^{b_n} EL_{n-1}(x) dx. \quad (16)$$

This procedure is repeated until all units have been considered and the resulting equivalent load curve includes the forced outage effects of all units. Additional information about the system can be obtained from the final equivalent load curve. Figure 6 shows this curve with the total

Fig. 6. Equivalent load curve for entire system.

system capacity, $\bar{X}_N$, also being plotted. P^* is the probability of having an equivalent load equal to or greater than the system generating capacity. Since the generating system would not be able to supply loads greater than the system capacity, P^* is the loss-of-load probability for the generating system. The area under the equivalent load curve to the right of the $\bar{X}_N$ (shaded area in Fig. 6) represents the expected energy demand that the generating system would not be able to serve:

$$U = T \int_{\bar{X}_N}^{\infty} EL_N(x) dx .$$

2.2 Hydroelectric Power Simulation

Hydroelectric power stations cannot be expected to generate energy to the limit of their availability since their fuel (water) supply is dependent upon variations in rainfall. Also these units may have a storage capability so that this inexpensive energy can be used during peak loads instead of energy from fossil fueled peaking stations. Because of these unique characteristics, different assumptions must be used to determine the amount of hydroelectric energy that will be used to satisfy system load. The difficulty does not lie in computing just how much of the hydro energy will be used since in nearly all cases all the available fuel (water) will be used to generate power. A utility could not afford to waste such cheap power. The problem is to determine *when* to use this energy to obtain the lowest overall production costs.

The code requires that the system contain one and only one hydro plant. If the system has no hydro facilities then a dummy hydro plant with zero capacity must be used. More likely, a multi-hydro system will have to be aggregated into a single unit simply by summing the capacities and energies. This single hydro plant is a two-piece plant with the base portion representing the run-of-river and the top piece representing the storage capability.

The base piece of the hydro plant is handled much like a thermal plant. This plant is placed in the first position in the economic loading order to simulate demand for this plant's energy over the entire interval.

The base portion delivers energy to the system to the limit of its availability. The plant is then convolved with the load duration curve to begin creation of the equivalent load curve. The top piece of hydro is handled in a special way to satisfy peak load thus reducing the energy required of peaking plants.

Before any plants are convolved with the load duration curve the energy corresponding to the top piece of hydro is used to reduce the actual load. This energy is equal to the amount of hydro energy that is specified for that interval less the amount that is generated by the base block. As shown in Fig. 7, the load is reduced by the difference in maximum and run-of-river capacity until this hydro storage energy is exhausted. An approximation is made with regard to this top piece as its forced outage rate is not used in generating the equivalent load curve. Instead,

Fig. 7. Modified equivalent load curve.

the top piece is treated deterministically by derating the capacity. This approximation, however, is not serious since hydro plants usually exhibit low forced outage rates.

The PRODCOST code uses the same procedure that the WASP code uses in dispatching hydro energy. The code does not have the capability to optimize hydro energy usage among time intervals (e.g. among months in a year). The data which specifies how much hydro energy is available to each study interval must be supplied as input. Historical hydro information can be obtained from the Power System Statement, Schedule 2, that is filed annually by each utility with the Energy Information Administration.

2.3 Simulation of Pumped Storage Units

Pumped storage units are used for peak shaving duty to reduce the system production costs. These units operate during times of peak load to off-load expensive combustion turbines using water in the storage pond that was pumped there by base load units during times of low load.

As with the hydroelectric plant, the PRODCOST code will accept at most only one pumped storage plant. However, if the system doesn't contain a pumped storage plant the code doesn't require a dummy plant unless one will be added during subsequent intervals. The capacity of this composite plant is the sum of the individual plants. Each of these plants has a certain cycle time which includes the time required to completely fill the reservoir plus the minimum time needed to deplete the reservoir when generating. The maximum amount of energy that can be delivered by each plant is equal to the interval length divided by the cycle time multiplied by the energy delivered per draw down. These energies are summed to yield the maximum energy which the composite plant is capable of delivering per interval. The cycle efficiency is assumed to be 85% in each direction, but can be changed by altering the value assigned to the variable PSEFF in the MAIN program of PRODCOST.

As the code computes the energy contribution of each thermal plant, it also determines the energy available for pumping and the energy that

could be off-loaded if the pumped storage plant was generating. The capacity of the pumped storage plant in both the pumping and generating modes as well as the appropriate availabilities are taken into account when determining the possible pumping and off-loading duties of each plant. The high cost plants will be offloaded only if (1) the generation energy is available from the pumped storage plant, (2) pumping energy is available from less expensive plants, and (3) the following constraint can be met:

$$\text{Pumping Cost} < \text{Displaced generation cost} \times 0.85 \times 0.85$$

The code starts with the most expensive plant and determines if there is sufficient generating and pumping energy available for off-loading in addition to the amount that must be used to satisfy the dispatching of the pumped storage unit at peak load. If the pumping energy satisfies the economic constraint, then the next most expensive plant is checked to determine if it can be off-loaded which will require more pumping energy from increasingly costly plants. Eventually, the economic constraint will not be met or there will no longer be sufficient energy to pump or the generation capability of the reservoir will be exhausted. No further pumped storage operation will take place in that time interval.

2.4. External Purchases and Sales

Purchases from and sales to a utility system outside the one being modeled for a fixed amount of energy and power can be represented explicitly in PRODCOST. The user inputs the power and energy levels of the transaction(s) and the cost of the purchase power (if applicable) by interval (e.g., by month). Up to five separate firm purchases and five firm sales can be modeled.

The modeling is done in a similar manner for both firm purchases and sales. Both cause the load curve to be modified. An assumption inherent in the approach for both purchases and sales is that purchases and/or sales occur during the times of peak load. In the program this means that changes to the load curve start at the far right of the curve (point of

highest load). For purchases, the load curve is shifted to the left (direction of lower loads) by the power level of the purchase until the energy limit of the purchase is encountered. For sales, the curve moves to the right by the power level of the sale until the energy limit of the sale is encountered. The approach is similar to hydro off-loading discussed in Sect. 2.2. Simulation of the operation of the plants in the system being modeled is performed based on this modified load curve. Figure 7 shows the effect of an external purchase on the load curve.

2.5 Two-piece Representation of Units

All base and intermediate loaded units must be modeled in two pieces. This is required to allow for modeling of spinning reserves. The first piece of a unit, which will be referred to as the base or lower piece, represents the maximum capacity of the unit less the spinning reserve contribution of that unit. The remaining piece represents the spinning reserve contribution. Each piece has a separate position in the loading order. The loading order subroutine, SEQUEC, will maintain a user-supplied spinning reserve requirement by delaying the loading of the upper pieces of units until sufficient spinning reserve exists to allow an upper piece to be loaded and still maintain the spinning reserve requirement. Once all units have been loaded (at least the lower pieces), the spinning reserve requirement is dropped and any remaining top pieces are placed in the loading order.

3. DESCRIPTION OF PRODCOST MAIN PROGRAM AND SUBPROGRAMS

MAIN Program

MAIN is the controlling program in PRODCOST. Subroutine calls which perform the actual simulation originate in MAIN. The activities in MAIN reflect the flow in the program and will be discussed in order of occurrence. First, variables and arrays are assigned initial values. Many are assigned the value of zero through a call to a local system subroutine called ZERO. Next, the user-prepared input data is read (see section 4.1). Once all the input data has been read, an initial loading order (for listings purposes only) is determined, if not input by the user, by a call to SEQUEC. The annual maintenance schedule is then calculated, if necessary, by a call to MNTNCE. The input data is then printed to the output file (e.g. line printer).

At this point the program enters a loop to perform the simulation. The activities within the loop consist of the following:

- Make any fuel changes for a given plant (subroutine FUCH).
- Establish loading order, if necessary, (subroutine SEQUEC).
- Develop discrete inverted load curve (subroutine LOADS).
- Calculate expected operation of each plant (subroutine SIMUL).
- Total various quantities.
- Store results in subroutine MOSUM.
- Depending on the option selected, print results for that interval.

These activities within the loop are performed for each interval of the year.

At the completion of the interval loop, a yearly summary is printed showing aggregate totals for costs, energy generated, LOLP, heat rates, and quantities of fuel consumed. Next, an annual summary by plant showing energy generated, cost, capacity factor, and fuel consumption is given. The program then returns to the point of initialization and begins to read new input data to start the simulation of a subsequent year. If there is no subsequent year to be simulated, the code then calls subroutine CHECK which prints a one line summary of the simulation. Execution of the program then ceases. A flowchart showing the major activities and responsible subroutine is presented as Fig. 8.

Fig. 8. Flowchart of major activities within PRODCOST.

Subroutine CHECK

Called by MAIN immediately before execution ceases, this subroutine prints a one-line summary of each year's simulation. Cost, energy, fuel consumption, and capacity factor are given.

Subroutine DISMOD

Called by subroutine SIMUL this subroutine modifies the equivalent load curve to reflect the random forced outage of a unit. In general, the equivalent load curve is shifted to the right (i.e. higher probability of a given load) by Eq. 15 shown in Sect. 2.1.

Subroutine ENG

Subroutine ENG is called by subroutine SIMUL and calculates the expected energy to be generated by a given unit based on its position on the equivalent inverted load curve. Expected hours of operation are also determined here.

Subroutine FUCH

FUCH performs two separate functions. The first is to escalate the fuel costs input through index 15 at the beginning of each year (excluding the initial year) in a multiple year simulation. The second purpose is to change the type of fuel consumed in a given plant. The new fuel must be one of the twelve types defined in index 15. If FUCH is used to change fuels in a plant, generic data cannot be used in index 4 (i.e., each plant in index 5 must have a separate card in index 4).

Subroutine IDAY

Called by MAIN, this is a local system subroutine that returns the current date as an argument in A8 format. For computer systems outside ORNL, an equivalent local routine will have to be substituted.

Subroutine LOADS

LOADS establishes a discrete inverted load curve from the polynomial representation of the load duration curve in index 3 (see Sect. 4.1). The subroutine returns to MAIN with the load probabilities in the PROB array.

Subroutine MNTNCE

Subroutine MNTNCE schedules annual plant maintenance. In PRODCOST, maintenance is scheduled in terms of complete intervals. When the annual maintenance period input in index 5 extends for a complete interval or more, the maintenance outage is scheduled for a whole interval (or intervals) with any remainder used to derate the capacity of the unit for a subsequent interval. Similarly, when a unit has less than a full interval given as its annual maintenance requirement, a capacity derating is applied to the unit for a selected interval. Maintenance intervals are selected by searching for the interval with the largest reserve margin. It has been assumed that nuclear plants must have their annual maintenance in a continuous space of time. Thus if a nuclear plant has an annual maintenance requirement of 1.5 intervals, the two intervals selected (one with a full outage; the other a 50% derating) will be contiguous. This is not a requirement for fossil units.

The subroutine assigns maintenance to plants in order of decreasing size. Maintenance for a given plant is assigned to the interval with the highest reserve margin (available capacity being adjusted accordingly). It is assumed that new units coming on-line as well as those units that are retiring during a given year will not require scheduled maintenance in that year. The process of searching for the largest unit still requiring maintenance and the interval with the largest reserve margin continues until all maintenance has been scheduled. The program then returns to MAIN.

Subroutine MOSUM

Subroutine MOSUM stores the aggregate simulation results (e.g. total cost, total energy, etc.) by interval. It also has two entry points (ANSUM1 and ANSUM2) which print the aggregate results by interval at the end of each year's simulation. See Sect. 4.2 for discussion of the output items presented.

Subroutine PAGE

Subroutine PAGE prints the results of the simulation. Depending on the option selected, PAGE will provide results by interval and generic

fuel type or by interval by plant. PAGE also prints the annual summary by plant. See Sect. 4.2 for discussion of the output items presented.

Subroutine SEQUEC

SEQUEC determines the plant loading order in each interval. Basically, it loads plants in ascending cost order considering the two piece representation of base and intermediate loaded fossil and nuclear plants. Spinning reserve requirements can also be included in the determination.

Initially the subroutine determines which plants are nuclear, base loaded fossil-fired, and intermediate loaded fossil-fired. All nuclear plants and base and intermediate loaded fossil plants must be two piece plants. First in the loading order are the bottom pieces of the nuclear and any base loaded fossil plants (in ascending cost order). The upper pieces are placed in the loading order in ascending cost order when (1) they do not violate the spinning reserve requirement, and (2) they are less costly than the next bottom piece not yet loaded (e.g. intermediate fossil or peaking plant). Finally, the pumped storage plant is placed in the loading order if present. The subroutine also has the ability to list each plant in the loading order and its effect on spinning reserve. The subroutine then returns to the MAIN program.

Subroutine SIMUL

Subroutine SIMUL is the heart of the PRODCOST code. In this subroutine, the determination of expected energy generation of all the units on the system is made. Adjustments to the equivalent load curve to reflect forced outages of units are also made here. The specific activities in the subroutine will now be discussed in the order they take place.

First, adjustments to the inverted load curve to reflect firm external purchases and sales are made. These adjustments are discussed in Sect. 2.4 and result in a modified load curve such as shown in Fig. 7. Next, the conventional hydro energy that can be used for meeting peak demand is accounted for by modifying the load curve (see Sect. 2.2). At this point, the determination of each unit's expected energy begins. As discussed in Sect. 2.1, the energy is calculated through a discrete representation of Eq. 16 in Sect. 2.1. This is done in SIMUL with a call to

subroutine ENG. In order to later determine the effect of pumped storage operation (if any) on each unit, subroutine ENG is actually called three times for each unit; first, as if there is no pumped storage facility, second, with the load of the pumped storage pumps on the system, and third, as if the pumped storage plant was generating power. The amount of energy expected from a given unit under each of these scenarios is stored in arrays for later use until all units have been considered. It is during this process of calling ENG that adjustments to the equivalent load curve to reflect each unit's forced outage rate are made. After each unit's expected energy generation has been determined, the equivalent load curve is modified by a call to subroutine DISMOD. DISMOD operates on the equivalent load curve as shown in Eq. 15 in Sect. 2.1.

One other subroutine may also be called during the process of calculating expected energies. As base and intermediate loaded units are modeled in two pieces, when considering the upper piece of a unit the forced outage effect of the lower piece (already in the equivalent load curve) must be removed. Otherwise, the upper piece would be supporting the outage of the bottom piece which is not possible. To prevent this, subroutine XMOD is called whenever a top piece is being considered. XMOD removes from the equivalent load curve the forced outage effects of the lower piece of a unit under consideration.

After the expected energies of all units have been calculated, the amount of pumped storage operation is determined. This is described in greater detail in Sect. 2.3, but briefly pumped storage operation is scheduled as long as (1) the cost to pump is less than cost savings of the deferred generation, (2) pumping energy is available, and (3) the reservoir capacity (generating ability) has not been exhausted. It is here that the possible states of energy generation by each unit mentioned earlier are used.

Once pumped storage operation has been determined, the loss of load probability (LOLP) and amount of expected unserved energy are calculated. SIMUL returns to MAIN and is recalled for each interval of the simulation.

Subroutine XMOD

This routine removes the forced outage effects of a given unit from the equivalent load curve. It is called from subroutine SIMUL when the upper piece of a two-piece unit is under consideration and the forced outage effects of the lower piece of that unit must be removed from the equivalent load curve. The computations in XMOD are the reverse of those performed in subroutine DISMOD.

Subroutine ZERO

Subroutine ZERO is a local system subroutine which assigns a value of zero to variables or arrays defined by the user. ZERO is used for this purpose since large amounts of core can be set to zero with one call to ZERO.

4. INPUT/OUTPUT DESCRIPTIONS

4.1 User Input Instructions

The PRODCOST code requires approximately 260 K bytes of core for execution. Typical running time on an IBM 3033 is 6-7 CPU seconds per simulation year. In addition to line printer output, PRODCOST writes to two disk files (which can be scratch files for the duration of the job).

Input to PRODCOST consists of a series of index controlled data cards (or card images). Referring to Table 1, there are twenty-one separate input elements (not all of which are required). The first card of any element must be an index card in I3 format identifying that element. The remaining cards within any element are described further in Table 1. If the user elects to skip certain input elements, the index for that element must also be omitted. All input for a given year should be in ascending index sequence. To simulate a series of years, place the data for year $n + 1$ (in order of increasing index number) immediately following the two cards of element 20 for year n . Index card 21 should be used only once at the very end of the input data stream. A sample input is shown in Appendix B.

4.2 Description of PRODCOST Output

The following will discuss the sample output shown in Appendix C. The first page of output presents the load data, the firm purchases and sales data, and the conventional hydro plant data. The load data, listed for each interval of the year, consists of the peak load in megawatts for the interval, the number of hours in the interval, the six coefficients of the fifth degree polynomial (highest degree coefficient first) and the year of the study. The firm sales data follows the load data and lists the name, energy, and power of each firm sales contract up to a maximum of five separate sales contracts. The energy and power are given for each interval of the year. The firm purchase data is next and lists in addition to the name, energy, and power of each contract (up to a maximum of five) the cost of the purchase energy. This cost is included in the total

Table 1. User input key

Index	Card	Ccolumns	Format	Variable	Entry
1	1	1-3	I3		1
	2	1-80	20A4	TITLE	Title of current simulation.
2	1	1-3	I3		2
	2	1-6	F6.0	DM	Size in MW of the discrete steps of the equivalent load curve. Recommended value is total system capacity divided by 300. If not entered, default value is 100 MW.
3	1	1-3	I3		3
	2	1-3	I3	JMO	Number of load intervals per year. Suggested values are 1, 2, 3, 4, 6, or 12. If zero or blank, default value is 12.
	3	1-80	20A4	TIT	Interval title card. The name of the interval should be the first 8 characters.
	4	1-10	F10.1	XL(1,*)	Interval peak load, MW
		11-16	F6.1	XL(2,*)	Hours during the interval
		17-25	F9.5	XL(3,*)	Coefficient of x^5 in polynomial defining the load duration curve. A fourth degree polynomial may be used by setting this coefficient equal to zero.
		26-34	F9.5	XL(4,*)	Coefficient of x^4
		35-43	F9.5	XL(5,*)	Coefficient of x^3
		44-52	F9.5	XL(6,*)	Coefficient of x^2
		53-61	F9.5	XL(7,*)	Coefficient of x
		62-70	F9.5	XL(8,*)	Constant in polynomial
		72-75	A4	XL(9,*)	Interval name
		77-80	I4	NYR	Year
	5	Similar to cards 3 and 4 respectively for intervals 2 through JMO. The sequence is title,			
	6	coefficients; title, coefficients, etc. A total of 2*JMO data cards are required. The second			
	etc.	index of the XL array (denoted by * above) varies from 1 to JMO.			
4	1	1-3	I3		4
	2	1-3	I3	NUM	Number of data cards to be read. Must be less than or equal to 200.
	3	1-3	I3	N	Plant or generic type number.
		5-12	2A4	NAMP(N)	Plant or generic type name.
		13-16	I4	NPTYP(N)	Generic fuel type (see Table 2).

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
		19-24	F6.0	FCST(N)	Fuel cost (cents per million Btu) or fuel type number as defined in index 15. The normal procedure is to supply the fuel cost here. An alternative is to supply the fuel type here, the fuel data under index 15, and to use index 17. See index 17 for further details.
		25-30	F6.0	HVAL(N)	Heat value of fuel, million Btu per unit Typical entries would be 23.0 million Btu/ton coal, 5.8 million Btu/bbl oil, 1.0 million Btu/thousand ft ³ gas.
		31-36	F6.0	FOM(N)	Fixed O&M cost, \$/MW/interval.
		37-42	F6.0	VAR(N)	Variable O&M cost, mills/kWh
		43-48	F6.0	FESC(N)	Fuel cost escalator
		49-54	F6.0	OMESC(N)	O&M cost escalator The fuel and O&M escalators are yearly multipliers. Constant costs are represented by an escalator of 1.0; escalation at 6% a year by an escalator of 1.06. If fuel and O&M escalators are omitted, default value of 1.0 will be assigned.
	4				Similar to card 3 for items 2 through NUM. A total of NUM data cards are required. If generic values are not used in index 4, then a card should be supplied for each plant given in index 5.
	etc.				
5	1	1-3	I3		5
	2	1-3	I3	NUM	Number of plant data cards to be read. Must be less than or equal to 200.
	3	1-3	I3	N	Plant number
		5-12	2A4	NAME(N)	Plant name
		13-16	I4	NOGEN(N)	Number of units operating at plant
		17-20	I4	NTYPE(N)	Type of operation (see Table 2).
		21-24	I4	NPLANT(N)	Reference to index 4. This associates a plant with a given fuel and O&M cost and allows use of generic fuel and O&M values in index 4. If generic values are not used in index 4, then NPLANT should have the same value as N in index 4.
		25-30	F6.0	MWB(N)	Lower or base piece unit output, MW. All intermediate and base loaded units are simulated in two pieces, each piece being loaded separately. For pumped storage units, this is the generating capacity. For peaking units, MWB must equal MWC.
		31-36	F6.0	MWC(N)	Maximum unit capacity, MW. For pumped storage units, this is the pumping capacity.
		37-42	F6.0	BTUKWB(N)	Heat rate (Btu/kWh) at MWB output.

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
		43-48	F6.0	BTUKWC(N)	Incremental heat rate between minimum and maximum output (Btu/kWh). The total heat input at maximum load is $MWB*BTUKWB+(MWC-MWB)*BTUKWC$. If $MWB = MWC$, set $BTUKWC=BTUKWB$.
		49-54	F6.0	ENERGY(N)	Maximum energy output per interval, GWH (required only for pumped storage) for entire plant.
		55-60	F6.0	AVLBTY(N)	Availability; defined as 100% minus the forced outage rate during scheduled operation periods and expressed in percent. (Example, if plant availability is 95%, enter 95.0.)
		61-66	F6.0	FLYASH(N)	Flyash content, pounds per unit of fuel (may be omitted)
		67-72	F6.0	EOTASH(N)	Bottom ash content, pounds per unit of fuel (may be omitted)
		73-78	F6.0	AMN(N)	Length of annual maintenance period expressed in intervals defined in index 3. Hydro maintenance is performed through index 14.
4		Similar to card 3 for plants 2 through NUM. A total of NUM plant data cards are required.			
etc.		NOTE: Plant 1 must always be hydro, even if NOGEN = 0.			
6	1	1-3	I3		6
	2	1-6	F6.0	ECOST	Cost of unserved energy, mills/kWh
		7-12	F6.0	ECESC	Annual escalation multiplier for ECOST
					This index is optional; default values of 20.0 and 1.03 are used if it is omitted.
7	1	1-3	I3		7
	2	1-75	25I3	NORDER	Generating unit loading order: plant numbers in the desired loading order. Each base and intermediate plant should be listed twice, once for the lower (base load) portion and once for the upper portion. Peaking plants should be listed only once. All 16 cards are required, although in most problems the last several will be blank. The conventional hydro plant must always be included and be first in the loading order. Pumped storage, if present, should be last in the loading order.
	thru				
	16				
					This index is required if LOPT is 0 in index 20.
8	1	1-3	I3		8
	2	1-3	I3	NUM	Number of plant status change cards to be read
	3	1-5	I5	M	Plant number
	etc.	6-41	12I3	MEXP(N,J)	An integer in the Jth location indicates the change in the number of units in service during the Jth interval during the year. +1 indicates a unit entering service, -1 indicates a retirement. More than one unit change per interval is allowable.

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
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					The NEXP array is initialized at the beginning of each year to all 0, signifying that no changes in numbers of operating units occur. Data are required only for plants which will have changes during the year. For years when no units change status, index 8 may be omitted.
9	1	1-3	I3		9
	2	1-6	F6.0	ESCLO	Factor by which peak loads for each interval from previous year are to be multiplied to get peak loads for next year. This multiplies the peak load data entered under index 3. This index should not be used for the initial year of a study, but only for subsequent years. Index 18 should not be used if index 9 is used.

10	1	1-3	I3		10
	2	1-3	I3	NUM	Number of generating unit maintenance schedule cards to be read.
	3	1-3	I3	N	Plant number
	etc.	6-65	12F5.3	(UMAINT (N,J), J=1,12)	A value in the Jth location indicates how many unit-intervals of maintenance from plant N will be scheduled during the Jth time interval of the year. Fractional unit-intervals are allowed and result in capacity deratings for that interval. This index is required if MOPT is 0 in index 20.

11	1	1-3	I3		11
	2	1-72	12F6.0	(XLIM(I), I=1,12)	The maximum amount of maintenance, expressed in MW of capacity, that can be scheduled in time interval I. Default is 10,000 MW.

12	1	1-3	I3		12
	2	1-3	I3	NUM	Number of plant deration cards to be read.
	3	1-3	I3	N	Plant number
	etc.	6-65	12F5.3	(DERATE (N,J), J=1,12)	Capacity deration from MWC. Expressed as a decimal fraction and defined as maximum operating output divided by MWC. Derating only affects MWC except for peaking units where both MWB and MWC are changed since MWB must equal MWC. If the derating for a plant is the same for subsequent intervals the fields corresponding to the subsequent intervals may be skipped. Deratings are carried from year to year. If a change in the derating is necessary, index 12 must be used at the start of the applicable year. Only those cards (plants) requiring change are necessary to be input. The default is no deration.

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
13	1	1-3	I3		13
	2	1-3	I3	ISALES	Number of firm sales contracts
		5-7	I3	IPURCH	Number of firm purchase contracts
	3	1-8	A8	SNAM(I)	Name of sales contract I
	4	1-72	12F6.0	ESALE (I,J)	Energy sold under contract I in interval J, GWh
	5	1-72	12F6.0	SALELD (I,J)	Firm power sold under contract I in interval J, MW
	6	1-8	A8	PNAM(I)	Name of purchase contract I
	7	1-72	12F6.0	EPURCH (I,J)	Energy purchased under contract I in interval J, GWh
	8	1-72	12F6.0	PURCLD (I,J)	Firm power purchased under contract I in interval J, MW
	9	1-72	12F6.0	PURCOS (I,J)	Firm purchase cost for contract I in interval J, mills/kWh

If there are either no firm purchases or no firm sales, the respective cards may be omitted. For multiple sales or purchases, cards 3 through 5 or cards 6 through 9, respectively, are repeated. Firm purchase and sale data are not carried from year to year, but must be input each year they exist.

14	1	1-3	I3		14
	2	1-72	12F6.0	ENER(J)	Available hydro energy (GWh) by interval
	3	1-72	12F6.0	HMWB(J)	Minimum hydro output (MW) by interval
	4	1-72	12F6.0	HMWC(J)	Maximum hydro output (MW) by interval
				J=1,JMO	If this index is omitted, default values of ENER, HMWB, and HMWC are all zero, and all hydro generation is zero. If hydro generation is present this index must be used. ENER must be of sufficient magnitude to allow full time operation at minimum hydro output.
15	1	1-3	I3		15
					Fuel characteristics information Twelve types of fuels may be defined: #1 and #2 are gases, #3-5 are oils, #6-8 are coals, #9-11 are nuclear, #12 is hydro.
	2	1-72	12F6.0	HEVAL(K)	Heating values in million Btu per thousand cubic feet of gas, or per barrel of oil, or per ton of coal, entries for nuclear or hydro are not used. K corresponds to the twelve types of fuels.

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
15	3	1-72	12F6.0	FCOST(K)	Cost of fuel in cents per million Btu
	4	1-72	12F6.0	ESCF(K)	Escalation factor by which cost of fuel is multiplied annually K=1,12

Index 15 data must be supplied if either index 16 or 17 is used, and must be entered before them. If neither index 16 or 17 is to be used, omit index 15.

16	1	1-3	I3		16
	2	1-3	I3	NUM	Number of fuel change data cards to be read
	3	1-5	I5	N	Plant number
	etc.	6-41	12I3	NFUCH(N,J)	Fuel number as defined in index 15 to which plant N will change at start of interval J

A total of NUM data cards of this same format are required. Zeroes or blanks mean that no change will occur. A single plant may have several entries on the same card. This information is carried forward from year to year; if a permanent fuel change is desired, then a card containing the plant number followed by 12 zeroes or blanks should be used for the following year to preclude further changes. Use of index 16 is optional. If used, however, generic data can not be used in index 4; a card in index 4 must be supplied for each plant given in index 5. .

17	1	1-3			17
This index card does not require any following data. It specifies that fuel data in index 15 will be used in a special way to override that entered in index 4, as follows. Instead of entering fuel cost in columns 19-24 of card index 4, enter the fuel type number corresponding to index 15 in format I2 in columns 23-24 of cards in index 4. Then the cost, heat value, and fuel escalation factor from index 15 will override the corresponding data under index 4. This is especially useful when fuel costs are to be varied parametrically. This change is made only once for each index 17 card; if a subsequent cost change is desired, new cards for index 15 and a new card for index 17 are required. If this option is used, it must be used for all plants in the system - it is not allowable to use fuel data from index 15 for some plants and that from index 4 for others. This is an optional feature.					

18	1	1-3	I3		18
	2	1-72	12F6.0	(GWH(J), J=1,JMO)	Total GWH to be generated in interval J
		77-80	I4	NYR	Year

The peak loads entered as the first entry on cards in index 3 will be adjusted up or down to agree with the GWH(*) values. Index 9 should not be used if index 18 is used.

<u>Index</u>	<u>Card</u>	<u>Columns</u>	<u>Format</u>	<u>Variable</u>	<u>Entry</u>
19	1	1-3	I3		19
	2	1-6	F6.0	SRRFAC	Spinning reserve as fraction of peak load. If not used, default value is 0.0. For 5% spinning reserve, SRRFAC = 0.05.
20	1	1-3	I3		20
	2	1-4	I4	LOPT	If 0, use loading order read in index 7. If 1, program determines loading order.
		5-8	I4	MOPT	If 0, use maintenance schedule read in index 10. If 1, program determines maintenance.
		9-12	I4	IPR	If 0, annual summary only; no printout by interval. If 1, printout by interval and generic fuel type (if used) plus summary. If 2, printout by interval and plant plus annual summary.
This card causes program to execute problem for one year.					
21	1	1-3	I3		21 or more
This card causes a program stop.					

costs as will be discussed but not in the production expenses. No cost is input for the firm sales as their costs will be determined by the production simulation. Finally, hydro energy, minimum power, and maximum power by interval are shown. The minimum power represents the run-of-river portion of hydro that must run. The energy and maximum power values represent maximums for the interval.

The next page of output lists the units or plants in the system and the data input in index 4 (see Sect. 4.1). The fuel type number refers to the type of fuel used as listed in Table 2. The heat value refers to the heat content of the fuel and is expressed in millions of British thermal unit per unit of fuel. For oil this would be on a per barrel basis; for gas, per thousand cubic feet; for coal, per ton. The heat value for nuclear fuel may be omitted from the input as fuel consumption is expressed in megawatt-days. The resulting output will show a zero for the heat value of nuclear fuel.

Table 2. Fuel and Operation Types

Type	Index 4 NPTYP (fuel)	Index 5 NTYPE (operation)
1	Gas	Base load
2	Oil	Intermediate
3	Coal	Peaking
4	Nuclear	Emergency peaking
5	Hydro	Hydro
6	Pumped storage	Pumped storage

The next set of data to be printed is primarily index 5 input data. In addition to the name, the number of identical units at that site, the usage type (defined in Table 2), and the plant number in reference to index 4 are listed. The latter item allows one to use generic fuel and O&M data in index 4 and reference each plant in index 5 to a specific generic type found in index 4. If generic data are not used in index 4, the plant number is the same as the sequence number of the plant listing. The capacity, heat rates, energy, availability, and maintenance items also shown

on that page are described in Sect. 4.1 under index 5. The fly ash and bottom ash inputs are not used at this time. The next to the last item printed at the far right of the page is the variable cost of operation (consisting of fuel and variable O&M) at the base level of power output. The last item is the incremental variable cost of operation at any point between the base and maximum capacity output of the plant or unit.

What is printed next depends on the user input. If an expansion/ retirement schedule has been input through index 8, this will be printed by interval and plant. The maintenance schedule is next and is always printed by interval and plant. If a fuel change has been input through index 16, it will be listed by interval and plant. Next, if any unit deratings are used as input through index 12 they will be printed by interval and plant. The plant loading order follows this and lists by plant number the order in which plants will be loaded. Values greater than 1000 indicate the top portion of a base or intermediate loaded plant whose identity is determined by subtracting 1000 from the number listed. The base portion of that plant will have already been loaded. Listed below the loading order will be the cost of energy not served and the maintenance limit in megawatts by interval. The maintenance limit will either be input by the user in index 11 or default to 10,000 MW.

The remaining pages of output represent the results of the simulation. The TOTAL COSTS column includes all fuel and O&M costs, unserved energy costs, and costs of firm purchases. PRODUCTION EXPENSE reflects just the fuel and O&M costs of the native system. Purchases and unserved energy costs are excluded. The UNSERVED ENERGY COST is the product of the unserved energy and the per unit unserved energy cost. AVAILABLE CAPACITY corresponds to the sum of all the units in the system not out for maintenance at their derated capacity if applicable. Firm purchase power is also included in AVAILABLE CAPACITY. PEAK LOAD includes native system load as well as firm external sales. TOTAL RESERVE is the difference between AVAILABLE CAPACITY and PEAK LOAD. PERCENT RESERVE is TOTAL RESERVE divided by PEAK LOAD. MAINTENANCE OUTAGE is equal to the number of megawatts out for maintenance for the entire interval plus the summation over all units of the product of the fraction of the interval a unit is out for maintenance times its maximum capacity. The latter term is included since

many times units will not be out for the entire interval. LOSS OF LOAD PROBABILITY represents a pure decimal probability of not fully meeting demand. REQUIRED ENERGY is the energy that must be generated by the native system once firm purchases and sales have been included. Firm sales (purchases) increase (decrease) REQUIRED ENERGY. NATIVE GENERATION is the sum of all energy generated by each unit in the native system. UNSERVED ENERGY is the amount of energy that statistically the system is unable to provide to meet demand. ENERGY UNBALANCE is the discrepancy between energy generation and demand due to such things as computer round-off. SYSTEM CAPACITY FACTOR is NATIVE GENERATION divided by maximum system energy, which is defined as the product of total system capacity and the number of hours in the interval. The last half of the current output page consists of aggregate summaries of energy generation, heat rate, and fuel consumption for gas, oil, coal, nuclear and the combination of those four thermal types. For gas fuel consumption, MCF is millions of cubic feet.

Following the aggregate summaries is the summary of operation of each plant in the system. Each firm purchase and sale is also listed here. Finally, a one line summary of the year's simulation is printed. Although not presented in Appendix C, it is possible to get results by interval through the print option in index 20.

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APPENDIX A. VARIABLE NAME INDEX

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<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
A	CHECK	Temporary storage of short summary on disk
	LOADS	Coefficient of X^5 term in polynomial defining the Load Duration Curve (LDC)
	SIMUL	Interpolation factor for installed power
	MAIN	Same as LOADS
AMN	MAIN	Length of annual maintenance expressed as number of time intervals per year
AREA	LOADS	Area under LDC
AVE	MAIN	Average annual LOLP
AVLBTY	All	100% minus the forced outage rate
AX	All	Interpolation factor
AY	All	Interpolation factor
B	DISMOD	Interpolation factor
	LOADS	Coefficient of X^4 term of LDC
	SIMUL	Same as DISMOD
	XMOD	Same as DISMOD
	MAIN	Same as LOADS
BASH	PAGE	Bottom ash content by plant (not used in present version of code)
BCST	ALL	Cost of energy generated by base block (mills/KWh)
BIG	MNTNCE	Largest interval reserve margin
BMN	MAIN	Temporary storage of maintenance schedule
BOTASH	MAIN	Bottom ash content (lb/unit fuel) (not used)
BTUKWB	ALL	Minimum load heat rate (Btu/KWh). Same as maximum heat rate for peaking units
BTUKWC	All	Incremental heat rate between minimum and maximum load (Btu/KWh)
BX	ENG	Interpolation factor
BY	ENG	Interpolation factor
C	All	Coefficient of X^3 term of LDC
CAP	All	System capacity in interval
CB	All	Thousands of tons of coal used in each interval
CBTU	MAIN	Heat energy used per interval in coal plants (MBtu)
CBTUA	MAIN	Heat energy used per year in coal plants (MBtu)
CE	All	Total cost of displaced energy through use of pumped storage (PS)

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
CF	PAGE	Interval system capacity factor
CGEN	All	Total energy generated by coal plants in interval (GWh)
CGENA	MAIN	Total annual energy generated by coal plants (GWh)
CHR	All	Average coal plant heat rate (Btu/KWh)
CMAX	MNTNCE	Temporary storage of maximum unit capacity
COST	PAGE	Plant cost per interval (K\$)
CP	All	Cost of PS pumping energy
CRM CST	All	Incremental energy cost (mills/KWh)
CSTMX	SEQUEC	Same as BCST
CSTPK	SEQUEC	Same as CRM CST
CX	SIMUL	Cost of energy being displaced by pumped storage (mills/KWh)
CY	SIMUL	Cost of energy used to fill pumped storage reservoir (mills/KWh)
D	All	Coefficient of X^2 term of LDC
DEM	LOADS	Derivative of LDC
DERATE	MAIN	Plant capacity that is actually available divided by rated capacity
DIF	All	Fractional interval of maintenance
DM	All	Step size for equivalent LDC (MW)
DT	All	Length of time interval (hr)
E	MAIN	Coefficient of X term of LDC
	LOADS	Same as MAIN
	SIMUL	Required energy from pumped storage before any off loading occurs
ECESC	MAIN	Annual escalation multiplier for cost of unserved energy
ECK	SIMUL	Test to see if energy available for PS generation has been exceeded
ECOST	MAIN	Cost of unserved energy (mills/KWh)
ECX	All	Cost of unserved energy (\$)
EHY	SIMUL	Expected hours of operation
ELOSS	All	Energy not served (GWh)
ENER	MAIN	Available hydro energy by interval (GWh)
ENERGY	All	Maximum energy output (used only for pumped storage)
ENG	PAGE	Energy generated by interval by plant (GWh)

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
ENGB	All	Energy generated by base block of plant (GWh)
ENGOFF	SIMUL	Amount of energy for peak shaving from purchases, and peak hydro
ENGP	All	Energy generated by peak block of plant (GWh)
ENRGY	SIMUL	Energy from base block of hydro plant
ENUK	PAGE	Nuclear plant output (MWD)
ENY	SIMUL	Expected energy generated by plant before any pumped storage is considered
EPURCH	All	Amount of energy from purchase in interval
ESALE	All	Amount of energy from sale in interval
ESCF	MAIN	Annual fuel escalation factor
ESCLO	MAIN	Peak load escalation factor
EX	SIMUL	Area under LDC in increments of DM megawatts
EXPENG	SIMUL	Temporary storage of area for cases where MWP forces IDX to be negative
EXPHRS	All	Expected hours of operation
EXPNRG	All	Expected energy generated
EXX	All	Energy unbalance caused by computer rounding (GWh)
EXXX	MAIN	Annual energy unbalance (GWh)
F	MAIN	Constant term in polynomial of LDC, also used for computing fuel used
	LOADS	Same as MAIN
	PAGE	Units of fuel burned
FACTOR	All	Fractional part of unit out for maintenance in a given time interval
FACT2	MAIN	Factor which decreases power level to reflect partial maintenance of unit during interval
FASH	PAGE	Amount of fly ash (not used in present version of code)
FCOST	All	Cost of fuel (cents/MBtu)
FCST	All	Fuel cost (cents/MBtu), or if index 15 is used, FCST is fuel type number
FESC	All	Fuel cost escalator
FFF	All	Temporary storage
FIX	All	Fixed O&M cost (K\$/interval)
FLYASH	MAIN	Flyash content (lb/unit fuel) (not used)
FOM	MAIN	Fixed O&M cost (\$/MW/interval)

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
FRACT	LOADS	Interpolation factor
FUN	LOADS	LDC polynomial
FUNINT	LOADS	Integral of LDC polynomial
FUNSLP	LOADS	Derivative of LDC polynomial
GB	All	Amount of gas used per interval (MCF)
GTBU	MAIN	Heat energy used per interval in gas plants (MBtu)
GTBUA	MAIN	Heat energy per year in gas plants (MBtu)
GE	SIMUL	PS generation possible if unit is off loaded by PS
GGEN	All	Energy generated by gas plants per interval
GGENA	MAIN	Energy generated per year by gas plants
GH	SIMUL	Hours of operation of unit if off loaded by PS
GHR	All	Average gas plant heat rate (Btu/KWh)
GWH	MAIN	Total energy to be generated in interval (GWh)
HEVAL	All	Heat value of fuel (MBtu/unit fuel)
HMWB	MAIN	Minimum hydro output per interval (MW)
HMWC	MAIN	Maximum hydro output per interval (MW)
HRSB	All	Hours of operation of base block of plant
HRSP	All	Hours of operation of peak block of plant
HVAL	All	Heat value of fuel (MBtu/unit fuel)
I	All	Index
IA	SIMUL	Minimum allowable step size on LDC
ICHECK	SEQUEC	Flag to indicate changes made to IDCON
ICHK	SIMUL	Index
IDCON	SEQUEC	Holds peak blocks in economic order
IDEX	SEQUEC	Index
IDMRFP	SEQUEC	Store ID number of base load fossil plants
IDNUC	SEQUEC	Store ID number of nuclear plants
IDTEMP	SEQUEC	Temporary storage
IDTWO	SEQUEC	Store ID number of two-piece plants
IDX	All	Index of abscissa on LDC
IDY	All	Similar to IDX
IFLATE	MAIN	Flag indicates index 9 is used
II	SEQUEC	Number of upper pieces in IDCON
IIE	SEQUEC	Index
IJ	All	Index

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
IKK	SIMUL	Index
IN	All	Number of intervals on LDC for which $PROB > 0.9999$
IND	MAIN	Indicates which input index is being used
INN	SEQUEC	Loading order vector
INOTE	SEQUEC	Loading order print option. Must be changed in code to use
INT	SIMUL	Number of intervals along abscissa of inverted LDC
IPR	MAIN	Flag indicating which print option is used
IPURCH	All	Number of purchases for current year
IP1	SEQUEC	Index
IP2	SEQUEC	Index
ISALES	All	Number of sales for current year
IST	SIMUL	Number of intervals on abscissa of inverted LDC
ISTR	SEQUEC	Index
ITEMP	SEQUEC	Temporary storage
ITEST	MAIN	Temporary storage used to add 1000 to base portion of plants
ITST	MAIN	Flag indicates if print is necessary
IX	MNTNCE	Index
IY	MNTNCE	Index
IYR	MAIN	Current year in study
IZ	MNTNCE	Index
I1	SEQUEC	Index for cost test
I2	SEQUEC	Index for cost test
I7	SEQUEC	First plant in loading order (hydro)
J	All	Index
JDX	ENG	Index
JHOLD	SEQUEC	Temporary storage of plant ID for creation of NNN
.I.I.I	SEQUEC	Index
JK	All	Index
JMAX	SEQUEC	Number of items in loading order, less hydro
JMO	All	Number of intervals per year
JP	SIMUL	Index (decreasing) for loading order
JTYPE	SEQUEC	Flag for pumped storage
JX	SIMUL	Index for unit number

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
JZ	SIMUL	Flag
J1	All	Index
J2	SIMUL	Index
J3	SIMUL	Plant number index
J4	SIMUL	Plant number index
K	All	Index
KB	SIMUL	Index
KDY	ENG	Index
KER	SIMUL	Flag for PS deficiency (reservoir or pumping energy exhausted)
KINT	XMOD	Index
KJ	SEQUEC	Index
KK	All	Index
KKK	SEQUEC	Index
KL	ENG	Index
KN	SIMUL	Index
KPS	SIMUL	Position of PS in loading order
KU	SIMUL	Index
KX	SIMUL	Flag used to indicate PS is encountered in reverse loading order
KYR	All	Year counter
K1	MNTNCE	Index
	SIMUL	Plant number index
K2	SIMUL	Flag (0) for lower or (1) for upper block of plant
K4	SIMUL	Similar to K2
L	All	Index
LCNT	All	Line counter
LIMIT	All	Maximum DM steps on LDC
LINT	DISMOD	Index
LLL	DISMOD	Index
LM	SEQUEC	Index used to adjust IDCON
LOAD	LOADS	Locator index on LDC
LOPT	MAIN	Flag (0) - input loading order, (1) - program determines loading order
LX	SIMUL	Temporary storage
M	PAGE	Print option indicator

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
M	SEQUEC	Index
MAINT	All	Integer number of units to be down per station
MCNT	MNTNCE	Counter for maintenance intervals
MINLD	LOADS	Minimum system load for each interval
MLD	SIMUL	Counter for IN
MNT	All	One more than the required number full intervals of maintenance
MNTT	All	Integer length of annual maintenance
MONTH	All	Months of the year, or names of intervals
MONTHU	MAIN	Names of intervals
MOPT	MAIN	Flag for maintenance schedule
MRPLT	SEQUEC	Number of baseload fossil plants
MTT	All	Capacity on maintenance for interval (MW)
MW	SIMUL	Capacity of upper block, or base block (MW)
MWB	All	Rating of base block of plant (MW)
MWBASE	SEQUEC	Same as MWB
MWC	All	Maximum unit capacity (MW)
MWG	SIMUL	Generating capacity of PS (MW)
MWIN	SIMUL	Sum of capacities at this point in loading order
MWINST	SIMUL	Total installed capacity at this point in calculation
MWOFF	SIMUL	Capacity available for off loading. Either purchase capacity or upper block of hydro
MWP	SIMUL	Pumping capacity of PS (MW)
MWPEAK	SEQUEC	Same as PKMW
MWPK	SEQUEC	Interval peak load (MW)
M1	MNTNCE	Maintenance counter
M2	MNTNCE	Maximum interval maintenance required (includes partial intervals)
N	MAIN	Plant number
	SEQUEC	Index
	PAGE	Plant number
	MNTNCE	Plant expansions, and plant number
NAME	All	Plant name (index 5)

Symbol	Routine	Definition
NAMP	All	Plant name (index 4)
NAMP2	MAIN	2nd half of plant name (index 4)
NAM2	MAIN	2nd half of plant name (index 5)
NBOY	SEQUEC	Number of nuclear and fossil plants
NEW	SIMUL	Index
NEXP	All	Flag for change in number of units in interval, +1 unit entering service, -1 unit leaving service
NFUCH	MAIN	Fuel number to which plant will change at start of interval
NFUEL	MAIN	Fuel type as defined in index 15
NLOAD	LOADS	Index of interval on LDC used to calculate inverted LDC
NNN	SEQUEC	Temporary storage of nuclear and fossil plants ID's in economic order
NNORD	All	Number of units in loading order
NOGEN	All	Number of units at each plant
NOLD	SIMUL	Index
NONUC	SEQUEC	Number of nuclear plants
NOPLTS	MAIN	Number of plants in index 4
NOPSU	MAIN	Number of pumped storage units
NORDER	All	Loading order
NOSETS	All	Number of units available at plant
NOSTNS	All	Number of plants in index 5
NOUT	MOSUM	Output device number (=18 in current version)
NPD	All	Index for interval
NPLANT	All	Plant number for summary purposes (index 5)
NPTYP	All	Plant type (index 4)
NTWO	SEQUEC	Number of two-piece plants
NTYPE	All	Plant type (index 5)
NU	MAIN	Logical unit used for data input (=5 in current version)
NUGEN	MNTNCE	Number of units exclusive of retirements and additions
NUM	MAIN	Number of input data cards to be read
NUMBER	SEQUEC	Index
NYR	All	Current year of study
NZ	SIMUL	Number of generating units at plant

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
OB	All	Amount of oil used in interval (bbl)
OBTU	MAIN	Heat energy used per interval in oil plants (MBtu)
OBTUA	MAIN	Heat energy used per year in oil plants (MBtu)
OENERG	MAIN	Maximum pumped storage energy before O&M deratings
OGEN	All	Total energy generated by oil plants in interval (GWh)
OGENA	MAIN	Total energy generated per year by oil plants (GWh)
OHR	All	Average oil plant heat rate (Btu/KWh)
OMESC	MAIN	O&M cost escalator
OMWB	MAIN	Capacity of base block (MW)
OMWC	MAIN	Maximum unit capacity (MW)
P	All	Availability (fraction)
PCOS	MAIN	Cost of purchase for interval
PE	SIMUL	Pumping energy available from unit if it pumps
PENG	All	Pumping energy
PH	SIMUL	Hours of operation if plant provides pumping energy
PKMW	All	Interval peak load (MW)
PKPURP	All	Peak purchase capacity (MW)
PKSALP	All	Peak sale capacity (MW)
PLOAD	LOADS	Predicted load used to calculate inverted LDC
PLOFL	All	Loss of load probability
PMCOST	All	Interval cost of all purchases
PNAM	MAIN	Purchase name
PPG	SIMUL	Required pumping energy for PS operation
PPS	SIMUL	Availability of PS
PROB	All	Discrete LDC
PROBLD	SIMUL	Same as PROB
PSEFF	MAIN	Round trip efficiency of PS (in current version PSEFF = 0.85 x 0.85)
PURCLD	All	Purchase capacity (MW)
PURCOS	MAIN	Purchase cost (\$/MWh)
PURCOT	MAIN	Yearly cost of all purchases
PX	SIMUL	Adjusts LDC for purchases and peak hydro
Q	All	Forced outage rate (fraction)
QUANT	MAIN	Amounts of each type of fuel used by interval

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
R	LOADS	Dummy variable of LDC
RM	MNTNCE	Reserve margin (MW)
RSV	All	Maximum reserve in interval (MW)
S	LOADS	Dummy variable of LDC
SALELD	All	Sale capacity (MW)
SNAM	All	Sale name
SR	SEQUEC	Current spinning reserve as each plant is added to the loading order
SRR	SEQUEC	Required spinning reserve (MW)
SRRFAC	All	The required fraction of peak load needed for spinning reserve (index 19)
SRT	SEQUEC	New value of SR when top block is loaded
STATUS	SEQUEC	Number of available units at each plant
SUM	SIMUL	Running sum used to compute SUMX
SUMX	All	Required generation per interval after including external firm purchases and sales
SYSCF	All	System capacity factor for interval
T	LOADS	Dummy variable of LDC
TABL1	MOSUM	Temporary storage of simulation results by interval
TABL2	MOSUM	Temporary storage of simulation results by interval
TBTU	MAIN	Total heating energy per interval (MBtu)
TBTUA	MAIN	Total heating energy per year (MBtu)
TCB	MAIN	Amount of coal burned per year (Tons)
TCOST	MAIN	Total system cost per interval (includes unserved energy and purchase cost)
	MOSUM	Same
	SEQUEC	Base block cost
TDT	MAIN	Total hours in year
TE	All	Total energy generated in interval (GWh)
TECX	MAIN	Cost of unserved energy for the year (\$)
TESUM	MAIN	Total energy generated in year
TFC	MAIN	Total cost per year (\$)
TGB	MAIN	Amount of gas used in a year (MCF)
TGEN	All	Total generation in one interval (GWh)
TGENA	MAIN	Total generation during year (GWh)

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
THR	All	Average heat rate (Btu/KWh)
TIT	MAIN	Interval title (index 3)
TITLE	All	Title of calculation (index 1)
TLOAD	MAIN	Yearly required energy generation after including external firm purchases and sales
TLOSS	MAIN	Total unserved energy (GWh)
TMW	MAIN	Total capacity for interval (before deratings)
TMWW	MAIN	Maximum system energy possible for year (before deratings)
TOB	MAIN	Amount of oil used in one year (bbl)
TOTAL	SEQUEC	Temporary storage for cost test
TRM	MNTNCE	Summation of reserve margin
TXNB	MAIN	Yearly total of nuclear fuel used (MWD)
T1	All	Energy generated by given plant
T2	All	Cost to operate plant
T3	MAIN	Total possible energy generation
	PAGE	Plant capacity factor
T4	All	Annual plant use of gas (MCF)
T5	All	Annual plant use of oil (bbl)
T6	All	Annual plant use of coal (Tons)
U	LOADS	Dummy variable of LDC
UMAINT	MAIN	User supplied maintenance schedule
V	LOADS	Dummy variable of LDC
VAR	All	Variable O&M (mills/KWh)
W	LOADS	Dummy variable of LDC
X	LOADS	Index
XA	SIMUL	Interpolation factor
XBTU	MAIN	Heat energy used per interval by nuclear plants (MBtu)
XBTUA	MAIN	Heat energy used per year by nuclear plants (MBtu)
XC	LOADS	Index
XGEN	All	Energy generated in interval by nuclear plants (GWh)
XGENA	MAIN	Energy generated in year by nuclear plants (GWh)
XHR	MAIN	Average nuclear heat rate (Btu/KWh)
XI	LOADS	Index

<u>Symbol</u>	<u>Routine</u>	<u>Definition</u>
XKK	LOADS	Flag
XL	All	Interval load information and LDC data
XLIM	All	Maximum amount of maintenance that can be scheduled in interval (MW)
XMW	All	Total available capacity (MW)
XNB	All	Nuclear generation (MWD)
XOUT	MNTNCE	Amount of generating capacity out of service (MW)
XT	LOADS	Index
YC	LOADS	Index
YMW	All	Percent reserve (of peak load)
YP	LOADS	Index
YRPURC	All	Annual cost of purchase (\$)
YRPURE	All	Annual energy provided by purchases (GWh)
YRSALE	MAIN	Annual energy generated for sales (GWh)
YT	LOADS	Index
Z	LOADS	Dummy variable of LDC

APPENDIX B. SAMPLE INPUT DATA

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PROGRAMMER																PROBLEM															
DATE																PAGE 1 OF 5															
1	5	6	10	11	15	16	20	21	25	26	30	31	35	36	40	41	45	46	50	51	55	56	60	61	65	66	70	71	73	80	
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PRDC	AST																														
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12																															
JAN																															
7800.			744.				-8.59582			22.0327					-20.3335			8.02329												1980	
FEB																															
7600.			678.				-11.0980			28.5665					-26.1957			10.1257												1980	
MAR																															
7200.			744.				-4.94065			12.6288					-11.6205			4.49937												1980	
APR																															
7000.			720.				-18.8308			47.2417					-41.3478			14.6010												1980	
MAY																															
7600.			744.				-8.71743			21.5302					-18.4584			6.32769												1980	
JUN																															
9300.			720.				-16.8190			42.4271					-37.4091			13.4421												1980	
JUL																															
9800.			744.				-7.48182			19.4670					-18.4938			7.85921												1980	
AUG																															
10000.			744.				-6.71495			17.4946					-16.3939			6.66687												1980	
SEP																															
9000.			720.				-17.1168			43.2541					-38.0582			13.5165												1980	
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80 COLUMN ENTRY																	
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1	56	1011	1516	2021	2526	3031	3536	4041	4546	5051	5556	6061	6566	7071	73	80	
7400.		744.		-8.27909	21.4277		-19.3361	6.94042		-1.31967	1.00088					1980	
NOV																	
7800.		720.		-19.2445	50.2595		-46.7588	18.3695		-3.23249	1.00224					1980	
DEC																	
8000.		744.		-5.78845	15.6712		-15.4440	6.66983		-1.66097	1.00111					1980	
4																	
7																	
1 HYDRO			5		12												
2 PUMP STØ			6		12												
3 NUCLEAR			4		9		303.										
4 COAL			3		6		684.										
5 OIL			2		3		556.	4.6									
6 C TURB			2		4			4.6									
7 EMER TIE			2		5												
5																	
21																	
1 HYDRO			1	5	1						98.						
2 PUMP STØ			1	6	2	200.	200.			48.	94.					.66	
3 NUC 1			1	1	3	600.	1200.	10930.	10349.		81.					1.97	
4 NUC 2			1	1	3	181.	1000.	14740.	9326.		81.					1.97	
5 NUC 3			1	1	3	650.	1300.	10500.	10100.		81.					1.97	
6 COAL 1			0	1	4	400.	1000.	8750.	8167.		77.					1.63	
7 COAL 2			5	1	4	132.	1000.	15490.	9471.		80.					1.63	
8 COAL 3			2	1	4	240.	1000.	8900.	8271.		80.					1.63	
9 COAL 4			2	1	4	100.	1000.	9000.	8442.		86.					1.40	

80 COLUMN ENTRY																															
PROGRAMMER										PROBLEM										DATE					PAGE 3 OF 5						
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10	COAL	5			2		1		4		50.		200.		9500.		8806.					92.									1.20
11	COAL	6			4		2		4		12.		50.		11000.		10197.					92.									.80
12	QIL	1			1		2		5		100.		400.		9400.		8817.					86.									1.40
13	QIL	2			5		2		5		50.		200.		10180.		8696.					92.									.80
14	QIL	3			5		2		5		50.		200.		11000.		8780.					92.									.80
15	QIL	4			5		2		5		50.		200.		11170.		9307.					92.									.80
16	CT	1			2		3		6		50.		50.		16400.		16400.					88.									.70
17	CT	2			6		3		6		45.		45.		15800.		15800.					88.									.70
18	CT	3			6		3		6		40.		40.		15000.		15000.					88.									.70
19	CT	4			2		3		6		30.		30.		13800.		13800.					88.									.70
20	CT	5			3		3		6		10.		10.		13000.		13000.					88.									.70
21	EMER TIE				1		4		7		200.		200.		16000.		16000.					100.									0.0
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200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.	200.			
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14																																	
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40.	35.	50.	80.	75.	45.	40.	30.	30.	40.	48.	50.																						
125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.	125.			
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			6.20	5.76	5.76	21.																											
			425.	550.	800.	128.															55.												
1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1				
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9	1																																
14			-1																														
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1.04																																	
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NEW SALE																																	

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SALE																																
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	.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.		.200.			
PURCHASE																																
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(SEE ORNL/TM-7496 FOR DOCUMENTATION)

DATE: 12-02-80

PRODCOST *** S A M P L E C A S E ***

LOAD DURATION CURVE DATA

JAN	7800.0	744.C	-8.595820	22.032700	-20.333500	8.023290	-1.692070	1.001130	1980
FEB	7600.0	672.0	-11.098000	28.566500	-26.195700	10.125700	-1.898760	1.001410	1980
MAR	7200.0	744.0	-4.940650	12.628800	-11.620500	4.499370	-1.099130	1.000740	1980
APR	7000.0	720.C	-18.830800	47.241700	-41.347800	14.601000	-2.224850	1.001540	1980
MAY	7600.0	744.0	-8.717430	21.530200	-18.458400	6.327690	-1.278600	1.000860	1980
JUN	9300.0	720.0	-16.819000	42.427100	-37.409100	13.442100	-2.263650	1.001570	1980
JUL	9800.0	744.0	-7.481920	19.467000	-18.493800	7.859210	-2.004140	1.001340	1980
AUG	10000.0	744.C	-6.714950	17.494600	-16.393900	6.666870	-1.682690	1.001130	1980
SEP	9000.0	720.C	-17.116800	43.254100	-38.058200	13.516500	-2.186550	1.001510	1980
OCT	7400.0	744.0	-8.279090	21.427700	-19.336100	6.940420	-1.319670	1.000880	1980
NOV	7800.0	720.C	-19.244500	50.259500	-46.758800	18.369500	-3.232490	1.002240	1980
DEC	8000.0	744.0	-5.788450	15.671200	-15.444000	6.669830	-1.660570	1.001110	1980

FIRM SALES DATA

SALE												
ENERGY (GWH)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
POWER (MW)	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0

FIRM PURCHASE DATA

PURCHASE												
ENERGY (GWH)	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	0.0	0.0	0.0	0.0
POWER (MW)	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.0	0.0	0.0	0.0	0.0
COST (\$/MWH)	0.0	0.0	0.0	0.0	0.0	0.0	25.0	25.0	0.0	0.0	0.0	0.0

HYDRO PLANT DATA

ENERGY (GWH)	40.0	30.0	40.0	60.0	60.0	60.0	65.0	70.0	60.0	30.0	40.0	50.0
MIN PWR (MW)	40.0	35.0	50.0	80.0	75.0	45.0	40.0	30.0	30.0	40.0	48.0	50.0
MAX PWR (MW)	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0

PRDCCOST *** SAMPLE CASE ***

FOR THE YEAR 1980

PLANT NUMBER	NAME	FUEL TYPE	FUEL COST \$/MBTU	HEAT VALUE MBTU/UNIT	FIX O&M COST \$/MW/INT	VARI O&M COST \$/MWH	FUEL ESCALATOR	O&M ESCALATOR
1	HYDRO	5	0.0	0.0	0.0	0.0	1.100	1.000
2	PUMP STD	6	0.0	0.0	0.0	0.0	1.100	1.000
3	NUCLEAR	4	0.5500	0.0	803.00	0.0	1.100	1.000
4	CCAL	3	1.2800	21.00	684.00	0.0	1.100	1.000
5	CIL	2	4.2500	4.20	556.00	4.6000	1.100	1.000
6	C TURB	2	5.5000	5.75	0.0	4.6000	1.100	1.000
7	EMER TIE	2	5.0000	5.76	0.0	0.0	1.100	1.000

NUM- BER	NAME	UNITS	USACE TYPE	PLANT	CAPACITY - MW BASE MAX	HEAT RATES BASE INCR	ENERGY GWH	AVAIL- ABILITY	FLY ASH	BOF- ASH	MAINTEN- NANCE	DOLLARS/MWH BASE INCR
1	HYDRO	1	5	1	0.0 0.0	0. 0.	0.0	98.0	0.0	0.0	0.0	0.0 0.0
2	PUMP STD	1	6	2	200.0 200.0	0. 0.	48.0	94.0	0.0	0.0	0.66	0.0 0.0
3	NUC 1	1	1	3	600.0 1200.0	10930. 10349.	0.0	81.0	0.0	0.0	1.97	6.0115 5.6919
4	NUC 2	1	1	3	181.0 1000.0	14740. 9326.	0.0	81.0	0.0	0.0	1.97	8.1070 5.1293
5	NUC 3	1	1	3	650.0 1300.0	10500. 10100.	0.0	81.0	0.0	0.0	1.97	5.7750 5.5550
6	COAL 1	0	1	4	400.0 1000.0	8750. 8167.	0.0	77.0	0.0	0.0	1.63	11.2000 10.4538
7	COAL 2	5	1	4	132.0 600.0	15490. 9471.	0.0	80.0	0.0	0.0	1.63	19.8272 12.1229
8	COAL 3	2	1	4	240.0 600.0	8900. 8271.	0.0	80.0	0.0	0.0	1.63	11.3920 10.5869
9	COAL 4	2	1	4	100.0 400.0	9000. 8442.	0.0	86.0	0.0	0.0	1.40	11.5200 10.8058
10	COAL 5	2	1	4	50.0 200.0	9500. 8806.	0.0	92.0	0.0	0.0	1.20	12.1600 11.2717
11	COAL 6	4	2	4	12.0 50.0	11000. 10197.	0.0	92.0	0.0	0.0	0.80	14.0800 13.0522
12	OIL 1	1	2	5	100.0 400.0	9400. 8817.	0.0	86.0	0.0	0.0	1.40	44.5500 42.0722
13	OIL 2	5	2	5	50.0 200.0	10180. 8696.	0.0	92.0	0.0	0.0	0.80	47.8650 41.5580
14	OIL 3	5	2	5	50.0 200.0	11000. 8780.	0.0	92.0	0.0	0.0	0.80	51.3500 41.9150
15	OIL 4	5	2	5	50.0 200.0	11170. 9307.	0.0	92.0	0.0	0.0	0.80	52.0725 44.1547
16	CT 1	2	3	6	50.0 50.0	16400. 16400.	0.0	88.0	0.0	0.0	0.70	94.8000 94.8000
17	CT 2	6	3	6	45.0 45.0	15800. 15800.	0.0	88.0	0.0	0.0	0.70	91.5000 91.5000
18	CT 3	6	3	6	40.0 40.0	15000. 15000.	0.0	88.0	0.0	0.0	0.70	87.1000 87.1000
19	CT 4	2	3	6	30.0 30.0	13800. 13800.	0.0	88.0	0.0	0.0	0.70	80.5000 80.5000
20	CT 5	3	3	6	10.0 10.0	13000. 13000.	0.0	88.0	0.0	0.0	0.70	76.1000 76.1000
21	EMER TIE	1	4	7	200.0 200.0	16000. 16000.	0.0	100.0	0.0	0.0	0.0	128.0000 128.0000

EXPANSION SCHEDULE BY INTERVAL

1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	1	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0

MAINTENANCE SCHEDULE BY INTERVAL

1	C.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	C.0	0.0	0.0	C.0	C.0	0.0	0.0	0.0	0.0	0.0	0.66	0.0
3	C.0	0.0	1.00	0.97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	C.0	0.0	C.0	1.00	0.97	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	C.0	0.0	C.0	0.0	C.0	C.0	0.0	0.0	0.0	1.00	0.97	0.0
6	0.0	0.0	0.0	C.0	C.0	C.0	0.0	0.0	0.0	0.0	0.0	0.0
7	1.63	1.00	1.63	0.0	0.63	0.0	0.0	0.0	0.0	1.63	1.00	0.63
8	C.0	0.63	0.0	C.0	0.0	0.0	0.0	0.0	0.0	1.00	0.0	1.63
9	0.40	0.0	0.0	C.0	C.0	C.0	0.0	0.0	1.00	0.0	1.00	0.40
10	0.0	0.20	1.00	0.0	0.20	0.0	0.0	0.0	0.0	1.00	0.0	0.0
11	C.80	0.0	0.0	0.80	0.0	0.0	0.0	0.0	0.80	0.0	0.0	0.80
12	C.0	1.00	0.0	0.40	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	0.80	0.0	0.0	0.80	C.0	0.0	0.0	0.0	0.80	0.0	0.80	0.80
14	C.0	0.80	0.80	0.0	0.80	0.0	0.0	0.0	0.80	0.80	0.0	0.0
15	C.0	0.80	0.0	0.80	0.80	0.0	0.0	0.0	0.80	0.0	0.80	0.0
16	0.0	0.0	0.0	C.0	C.0	C.0	0.0	0.0	0.0	0.0	0.0	1.40
17	1.40	0.0	0.0	1.40	0.0	C.0	0.0	0.0	0.70	0.0	0.0	0.70
18	C.0	0.70	0.70	0.0	0.70	0.0	0.0	0.0	0.70	0.70	0.0	0.70
19	0.0	0.0	C.0	0.0	C.0	0.0	0.0	0.0	0.0	0.0	1.40	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.40	0.0	0.0	0.70
21	C.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

UNIT DERATINGS BY INTERVAL

1	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
4	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
5	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
8	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
10	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
11	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
15	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
16	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
17	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
18	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
19	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
20	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
21	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

LOADING ORDER

1	5	3	4	6	8	9	10	7	1004	1005	1003	1006	1008	1009	1010	1007	11	1011	12	1012	13	1013	14	1014
15	1015	20	19	18	17	16	21	2																

COST OF ENERGY NOT SERVED 200.00 MILLS/KWH ESCALATION 1.00

MAINTENANCE LIMITS (MW) 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000.

RESERVOIR EXHAUSTED IN INTERVAL . 8

PRGDCOST *** SAMPLE CASE ***

FOR THE YEAR 1980

MONTH	TOTAL CCSTS	PRODUCTION EXPENSE	UNSERVED ENERGY	AVAILABLE CAPACITY	PEAK LOAD	TOTAL RESERVE	PERCENT RESERVE	MAINT OUTAGE	LOSS LOAD	REQUIRED ENERGY	NATIVE GENERATN	UNSERVED ENERGY	ENERGY UNBALANCE	SYSTEM CAPACITY
	\$	\$	CCST,\$	MW	MW	MW		MW	PROBAB	GWH	GWH	GWH	GWH	FACTOR
JANUARY	55107751.	55094304.	13447.	12110.	8000.	4110.	51.37	1398.	0.001023	4279.	4342.	0.07	-0.20	42.52
FEBRUARY	50112675.	50091454.	21222.	11745.	7800.	3945.	50.58	1763.	0.001509	3889.	3938.	0.11	-0.29	42.70
MARCH	63637693.	63609675.	28013.	11029.	7400.	3629.	49.04	2479.	0.001812	4108.	4142.	0.14	-0.31	40.56
APRIL	56779911.	56770054.	9854.	10975.	7200.	3775.	52.44	2532.	0.000832	3774.	3839.	0.05	-0.12	38.85
MAY	56224031.	56206228.	17803.	11501.	7800.	4101.	52.58	1606.	0.001121	4111.	4170.	0.09	-0.18	40.84
JUNE	61839011.	61815041.	23971.	13511.	9500.	4011.	42.22	0.	0.001948	4656.	4717.	0.12	-0.53	47.73
JULY	63723647.	63498787.	49863.	13521.	10000.	3521.	35.21	0.	0.003697	4774.	4832.	0.25	-1.18	47.32
AUGUST	70142364.	69872071.	55293.	13521.	10200.	3321.	32.56	0.	0.006429	5028.	5088.	0.48	-2.06	49.82
SEPTEMBER	58764577.	58733950.	30627.	13517.	9200.	4317.	46.93	991.	0.002296	4618.	4661.	0.15	-0.62	43.97
OCTOBER	64510261.	64473054.	37207.	11245.	7600.	3645.	47.96	3264.	0.002489	4098.	4164.	0.19	-0.48	38.00
NOVEMBER	53756956.	53744990.	11965.	11756.	8000.	3756.	46.95	2753.	0.000969	3829.	3846.	0.06	-0.24	36.27
DECEMBER	53931596.	53921759.	9837.	12658.	8200.	4458.	54.37	1846.	0.000800	4281.	4325.	0.05	-0.15	39.48
ANNUAL	708530473.	707831366.	349107.						0.002088	51445.	52064.	1.75	-6.35	42.27

MONTH	GENERATION-GWH					HEAT RATE,BTU/KWH					FUEL BURNED			
	GAS	OIL	COAL	NUCLEAR	TOTAL	GAS	OIL	COAL	NUCLEAR	TOTAL	GAS-MCF	OIL-BBL	COAL-TONS	NUC-MWDAYS
JANUARY	0.0	209.7	2077.9	1968.4	4255.9	0.	9289.	9759.	10464.	10062.	0.	314418.	965654.	82015.
FEBRUARY	0.0	147.8	1938.1	1788.8	3872.7	0.	9428.	9926.	10463.	10155.	0.	225152.	916101.	74452.
MARCH	0.0	418.9	2350.3	1307.7	4077.0	0.	9262.	9684.	10361.	9858.	0.	626483.	1083843.	54488.
APRIL	0.0	203.9	2750.6	777.7	3732.2	0.	9321.	9878.	10309.	9938.	0.	306852.	1293861.	32404.
MAY	0.0	200.4	2399.1	1467.6	4067.1	0.	9282.	9885.	10467.	10065.	0.	300367.	1129292.	61150.
JUNE	0.0	244.2	2461.2	1907.1	4612.5	0.	9315.	9983.	10464.	10147.	0.	367473.	1170030.	79462.
JULY	0.0	260.5	2501.2	1962.1	4723.8	0.	9364.	9994.	10465.	10155.	0.	394317.	1190320.	81755.
AUGUST	0.0	363.9	2637.4	1971.7	4973.0	0.	9385.	9957.	10464.	10116.	0.	552382.	1250440.	82155.
SEPTEMBER	0.0	152.7	2514.6	1902.1	4569.4	0.	9346.	9860.	10464.	10095.	0.	230700.	1180704.	79256.
OCTOBER	0.0	400.6	2488.4	1198.8	4085.8	0.	9310.	9580.	10570.	9844.	0.	602250.	1135208.	49868.
NOVEMBER	0.0	168.1	2445.9	1179.3	3793.2	0.	9289.	9658.	10565.	9923.	0.	252083.	1124810.	49136.
DECEMBER	0.0	138.7	2140.2	1963.8	4242.8	0.	9285.	9953.	10464.	10168.	0.	207963.	1014393.	81827.
ANNUAL	0.0	2909.5	28704.8	19391.2	51005.5	0.	9321.	9843.	10464.	10049.	0.	4380441.	13454656.	807968.

PRUCCOST *** SAMPLE CASE ***

FOR THE YEAR 1980

NR.	NAME	RATING MW	ENERGY GWH	CCST \$ *1000	CAPACITY FACTOR	MCF GAS	88L OIL	TON COAL	MWD NUKE
1	HYDRC	125.	604.9	0.	55.2	0.	0.	0.	0.
2	PUMP STD	200.	453.1	0.	25.9	0.	0.	0.	0.
3	NUC 1	1200.	6538.7	49918.	62.2	0.	0.	0.	272447.
4	NUC 2	1000.	5157.2	39284.	58.9	0.	0.	0.	214883.
5	NUC 3	1300.	7695.3	56122.	67.6	0.	0.	0.	320639.
6	COAL 1	1000.	2138.4	25763.	73.0	0.	0.	856668.	0.
7	COAL 2	600.	11990.2	200760.	45.6	0.	0.	6552661.	0.
8	COAL 3	600.	6864.1	84859.	65.3	0.	0.	2790532.	0.
9	COAL 4	400.	4730.0	58629.	67.5	0.	0.	1936836.	0.
10	COAL 5	200.	2407.9	31068.	68.7	0.	0.	1033656.	0.
11	COAL 6	50.	574.2	9284.	32.8	0.	0.	284303.	0.
12	GIL 1	400.	788.2	36368.	22.5	0.	1141310.	0.	0.
13	OIL 2	200.	1394.9	67561.	15.9	0.	2067268.	0.	0.
14	OIL 3	200.	527.8	30570.	6.0	0.	814817.	0.	0.
15	GIL 4	200.	163.5	14398.	1.9	0.	264655.	0.	0.
16	CT 1	50.	2.6	245.	0.3	0.	7359.	0.	0.
17	CT 2	45.	9.5	867.	0.4	0.	25998.	0.	0.
18	CT 3	40.	12.4	1077.	0.6	0.	32207.	0.	0.
19	CT 4	30.	4.0	319.	0.8	0.	9508.	0.	0.
20	CT 5	10.	2.1	159.	0.8	0.	4715.	0.	0.
21	EMER TIE	200.	4.5	581.	0.3	0.	12604.	0.	0.

FIRM PURCHASES				
1 PURCHASE	10.	14.0	350.	

FIRM SALES			
1 SALE	200.	1200.0	

PRODCST *** SAMPLE CASE ***

LOAD DURATION CURVE DATA

JAN	8112.0	744.0	-8.595820	22.032700	-20.333500	8.023290	-1.692070	1.031130	1981
FEB	7904.0	672.0	-11.098000	28.566500	-26.155700	10.125700	-1.898760	1.031410	1981
MAR	7488.0	744.0	-4.940650	12.628800	-11.620500	4.499370	-1.099130	1.030740	1981
APR	7280.0	720.0	-18.830800	47.241700	-41.347800	14.601000	-2.224850	1.001540	1981
MAY	7904.0	744.0	-8.717430	21.530200	-18.458400	6.327690	-1.278600	1.030860	1981
JUN	9672.0	720.0	-16.819000	42.427100	-37.409100	13.442100	-2.263650	1.001570	1981
JUL	10192.0	744.0	-7.481920	19.467000	-18.493800	7.859210	-2.004140	1.001340	1981
AUG	10400.0	744.0	-6.714950	17.494600	-16.393900	6.666870	-1.682690	1.001130	1981
SEP	9360.0	720.0	-17.116800	43.254100	-38.058200	13.516500	-2.186550	1.001510	1981
OCT	7696.0	744.0	-8.279090	21.427700	-19.336100	6.940420	-1.319670	1.000880	1981
NOV	8112.0	720.0	-19.244500	50.259500	-46.758800	18.369500	-3.232490	1.002240	1981
DEC	8320.0	744.0	-5.788450	15.671200	-15.444000	6.669830	-1.660970	1.001110	1981

FIRM SALES DATA

NEW SALE												
ENERGY (GWH)	0.0	0.0	0.0	10.0	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0
POWER (MW)	0.0	0.0	0.0	20.0	20.0	20.0	0.0	0.0	0.0	0.0	0.0	0.0

SALE												
ENERGY (GWH)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
POWER (MW)	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0

FIRM PURCHASE DATA

PURCHASE												
ENERGY (GWH)	0.0	0.0	0.0	0.0	0.0	0.0	7.0	7.0	0.0	0.0	0.0	0.0
POWER (MW)	0.0	0.0	0.0	0.0	0.0	0.0	10.0	10.0	0.0	0.0	0.0	0.0
CGST (\$/MWH)	0.0	0.0	0.0	0.0	0.0	0.0	25.0	25.0	0.0	0.0	0.0	0.0

HYDRO PLANT DATA

ENERGY (GWH)	40.0	30.0	40.0	60.0	60.0	60.0	65.0	70.0	60.0	30.0	40.0	50.0
MIN PWR (MW)	40.0	35.0	50.0	80.0	75.0	45.0	40.0	30.0	30.0	40.0	48.0	50.0
MAX PWR (MW)	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0	125.0

PRODCOST *** SAMPLE CASE ***

FOR THE YEAR 1981

PLANT NUMBER	NAME	FUEL TYPE	FUEL COST \$/METU	HEAT VALUE MBTU/UNIT	FIX O&M COST \$/MW/INT	VARI O&M CCST \$/MWH	FUEL ESCALATOR	O&M ESCALATOR
1	HYDRO	5	0.0	0.0	0.0	0.0	1.100	1.000
2	PUMP STO	6	0.0	0.0	0.0	0.0	1.100	1.000
3	NUCLEAR	4	0.6050	0.0	803.00	0.0	1.100	1.000
4	CCAL	3	1.4080	21.00	684.00	0.0	1.100	1.000
5	OIL	2	4.6750	6.20	556.00	4.6000	1.100	1.000
6	C TURB	2	6.0500	5.76	0.0	4.6000	1.100	1.000
7	EMER TIE	2	8.8000	5.76	0.0	0.0	1.100	1.000

NUM- BER	NAME	UNITS	USAGE TYPE	PLANT	CAPACITY - MW BASE MAX	HEAT BASE	RATES INCR	ENERGY GWH	AVAIL- ABILITY	FLY ASH	BOT- ASH	MAINTEN- NANCE	DOLLARS/MWH BASE INCR
1	HYDRO	1	5	1	50.0 125.0	0.	0.	50.0	98.0	0.0	0.0	0.0	0.0 0.0
2	PUMP STO	1	6	2	200.0 200.0	0.	0.	48.0	94.0	0.0	0.0	0.66	0.0 0.0
3	NUC 1	1	1	3	600.0 1200.0	10930.	10349.	0.0	81.0	0.0	0.0	1.97	6.6126 6.2611
4	NUC 2	1	1	3	181.0 1000.0	14740.	9326.	0.0	81.0	0.0	0.0	1.97	8.9177 5.6422
5	NUC 3	1	1	3	650.0 1300.0	10500.	10100.	0.0	81.0	0.0	0.0	1.97	6.3525 6.1105
6	COAL 1	1	1	4	400.0 1000.0	8750.	8167.	0.0	77.0	0.0	0.0	1.63	12.3200 11.4991
7	COAL 2	5	1	4	132.0 600.0	15490.	9471.	0.0	80.0	0.0	0.0	1.63	21.8099 13.3352
8	COAL 3	2	1	4	240.0 600.0	8900.	8271.	0.0	80.0	0.0	0.0	1.63	12.5312 11.6456
9	COAL 4	2	1	4	100.0 400.0	9000.	8442.	0.0	86.0	0.0	0.0	1.40	12.6720 11.8863
10	COAL 5	2	1	4	50.0 200.0	9500.	8806.	0.0	92.0	0.0	0.0	1.20	13.3760 12.3588
11	COAL 6	4	2	4	12.0 50.0	11000.	10197.	0.0	92.0	0.0	0.0	0.80	15.4880 14.3574
12	OIL 1	1	2	5	100.0 400.0	9400.	8817.	0.0	86.0	0.0	0.0	1.40	48.5450 45.8195
13	OIL 2	5	2	5	50.0 200.0	10180.	8696.	0.0	92.0	0.0	0.0	0.80	52.1915 45.2538
14	OIL 3	5	2	5	50.0 200.0	11000.	8780.	0.0	92.0	0.0	0.0	0.80	56.0250 45.6465
15	OIL 4	5	2	5	50.0 200.0	11170.	9307.	0.0	92.0	0.0	0.0	0.80	56.8197 48.1102
16	CT 1	2	3	6	50.0 50.0	16400.	16400.	0.0	88.0	0.0	0.0	0.70	103.8200 103.8200
17	CT 2	6	3	6	45.0 45.0	15800.	15800.	0.0	88.0	0.0	0.0	0.70	100.1900 100.1900
18	CT 3	6	3	6	40.0 40.0	15000.	15000.	0.0	88.0	0.0	0.0	0.70	95.3500 95.3500
19	CT 4	2	3	6	30.0 30.0	13800.	13800.	0.0	88.0	0.0	0.0	0.70	88.0900 88.0900
20	CT 5	3	3	6	10.0 10.0	13000.	13000.	0.0	88.0	0.0	0.0	0.70	83.2500 83.2500
21	EMER TIE	1	4	7	200.0 200.0	16000.	16000.	0.0	100.0	0.0	0.0	0.0	140.8000 140.8000

EXPANSION SCHEDULE BY INTERVAL

1	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0
9	0	1	0	0	0	0	0	1	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0
14	0	0	-1	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0	0	0	0	0	0	0	0	0	0	0	0
17	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0

MAINTENANCE SCHEDULE BY INTERVAL

1	C.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.66	C.0	C.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	C.0	0.0	0.0	0.0	0.0	1.00	0.97	0.0
4	C.0	0.0	1.00	0.97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	C.0	0.0	1.00	0.97	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	1.00	0.0	0.0	0.63	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7	1.00	0.63	0.63	0.63	1.63	0.0	0.0	0.0	0.0	1.00	1.00	1.63
8	0.63	0.63	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.00	0.0	1.00
9	0.0	0.40	C.0	1.00	C.0	C.0	0.0	0.0	0.0	0.40	0.0	1.00
10	0.0	0.0	1.00	0.0	0.0	0.0	0.0	0.0	0.0	0.20	0.20	0.0
11	0.80	0.80	0.0	0.0	0.80	0.0	0.0	0.0	0.0	0.0	0.80	0.0
12	0.40	0.0	0.0	0.0	C.0	C.0	0.0	0.0	0.0	1.00	0.0	0.0
13	0.80	0.80	0.0	0.0	0.80	0.0	0.0	0.0	0.0	0.80	0.0	0.80
14	C.0	0.0	0.80	0.80	0.0	0.0	0.0	0.0	0.0	0.80	0.0	0.80
15	0.80	0.0	0.0	0.0	0.80	0.0	0.0	0.0	0.0	0.80	0.80	0.80
16	0.70	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.70	0.0
17	0.70	0.70	0.70	0.0	0.70	0.0	0.0	0.0	0.0	0.0	0.70	0.70
18	0.70	0.0	0.0	0.0	C.0	0.0	0.0	0.0	1.40	0.70	0.70	0.70
19	0.0	0.70	0.0	0.0	C.70	C.0	0.0	0.0	0.0	0.0	0.0	0.0
20	0.70	0.0	0.70	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.70	0.0
21	C.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

UNIT DERATINGS BY INTERVAL

1	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
3	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
4	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87
5	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
6	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
7	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
8	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
10	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
11	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
12	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
13	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
14	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
15	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
16	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
17	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
18	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
19	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
20	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
21	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

LOADING ORDER

1	5	3	4	6	8	9	10	7	1004	1005	1003	1006	1008	1009	1010	1007	11	1011	12	1012	13	1013	14	1014
15	1015	20	19	18	17	16	21	2																

COST OF ENERGY NOT SERVED 200.00 MILLS/KWH ESCALATION 1.00

MAINTENANCE LIMITS (MW) 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000. 10000.

RESERVOIR EXHAUSTED IN INTERVAL 3

PRODCOST *** SAMPLE CASE ***

FOR THE YEAR 1981

MONTH	TOTAL COSTS \$	PRODUCTION EXPENSE \$	UNSERVED ENERGY COST, \$	AVAILABLE CAPACITY MW	PEAK LOAD MW	TOTAL RESERVE MW	PERCENT RESERVE	MAINT OUTAGE MW	LOSS LOAD PRCBAB	REQUIRED ENERGY GWH	NATIVE GENERATION GWH	UNSERVED ENERGY GWH	ENERGY UNBALANCE GWH	SYSTEM CAPACITY FACTOR
JANUARY	59058207.	59046472.	11735.	12911.	8312.	4599.	55.34	1594.	C.COC897	4446.	4483.	0.06	-0.21	40.92
FEBRUARY	56295171.	56290184.	4986.	12742.	8104.	4638.	57.24	2164.	0.000355	4041.	4085.	0.02	-0.03	40.19
MARCH	69941105.	69929375.	11730.	11764.	7688.	4076.	53.02	2943.	0.001027	4268.	4322.	0.06	-0.18	38.92
APRIL	64122927.	64114994.	7933.	11536.	7500.	4036.	53.81	3172.	0.000733	3931.	3953.	0.04	-0.12	36.78
MAY	56740044.	56731211.	8833.	12690.	8124.	4566.	56.21	2017.	0.000774	4281.	4320.	0.04	-0.15	38.90
JUNE	65414557.	65402172.	12385.	14711.	9892.	4819.	48.72	0.	0.001006	4848.	4884.	0.06	-0.30	45.45
JULY	67232034.	67031979.	25055.	14721.	10392.	4329.	41.66	0.	0.001861	4961.	4996.	0.13	-0.61	45.00
AUGUST	70901036.	70699046.	26990.	15121.	10600.	4521.	42.65	0.	0.001835	5226.	5264.	0.13	-0.57	46.16
SEPTEMBER	63402355.	63392967.	9387.	14695.	9560.	5135.	53.71	413.	0.000595	4799.	4826.	0.05	-0.17	43.74
OCTOBER	62285099.	62259323.	25776.	12007.	7896.	4111.	52.06	3101.	0.001896	4258.	4304.	0.13	-0.44	37.75
NOVEMBER	56254335.	56248279.	6058.	12567.	8312.	4255.	51.19	2540.	0.000544	3978.	4007.	0.03	-0.15	36.32
DECEMBER	58634947.	58621923.	13024.	12953.	8520.	4433.	52.04	2155.	0.001009	4448.	4484.	0.07	-0.25	39.33
ANNUAL	750281818.	749767925.	163893.						0.001053	53485.	53928.	0.82	-3.16	40.79

MONTH	GENERATION-GWH					HEAT RATE, BTU/KWH					FUEL BURNED			
	GAS	OIL	COAL	NUCLEAR	TOTAL	GAS	OIL	COAL	NUCLEAR	TOTAL	GAS-MCF	OIL-BBL	COAL-TONS	NUK-MWDAYS
JANUARY	0.0	111.7	2342.5	1961.8	4416.0	0.	9340.	5698.	10465.	10030.	0.	168536.	1081816.	81742.
FEBRUARY	0.0	126.8	2108.9	1787.4	4023.1	0.	9264.	9901.	10463.	10131.	0.	189497.	994308.	74475.
MARCH	0.0	242.2	3328.1	672.5	4242.8	0.	9258.	9512.	10661.	9680.	0.	361921.	1507484.	28023.
APRIL	0.0	211.2	2977.1	688.8	3877.2	0.	9267.	9576.	10645.	9749.	0.	316032.	1357576.	28701.
MAY	0.0	115.3	2180.4	1936.1	4231.9	0.	9290.	9616.	10467.	9957.	0.	173064.	998422.	80671.
JUNE	0.0	123.9	2777.2	1897.0	4798.1	0.	9305.	9722.	10465.	10005.	0.	186271.	1285706.	79041.
JULY	0.0	136.9	2820.6	1947.8	4505.3	0.	9350.	5730.	10466.	10012.	0.	206909.	1306909.	81158.
AUGUST	0.0	144.8	3062.9	1958.1	5165.8	0.	9344.	9645.	10465.	9947.	0.	218664.	1406774.	81587.
SEPTEMBER	0.0	81.9	2764.1	1900.0	4746.0	0.	9295.	9701.	10464.	10000.	0.	122950.	1276908.	79166.
OCTOBER	0.0	139.1	2794.4	1306.8	4240.3	0.	9462.	9543.	10361.	9793.	0.	212857.	1269848.	54450.
NOVEMBER	0.0	80.1	2583.6	1282.2	3545.9	0.	9277.	9537.	10366.	9801.	0.	119995.	1173361.	53425.
DECEMBER	0.0	108.7	2336.4	1962.6	4407.7	0.	9299.	9510.	10464.	9930.	0.	163226.	1058088.	81775.
ANNUAL	0.0	1622.6	32076.2	19301.2	53000.0	0.	9310.	9635.	10465.	9927.	0.	2439921.	14717159.	804215.

PRGDCOST *** SAMPLE CASE ***

FOR THE YEAR 1981

NR.	NAME	RATING MW	ENERGY GWH	COST \$ *1000	CAPACITY FACTOR	PCF GAS	BBL OIL	TCN COAL	MWD NUKE
1	HYDRO	125.	604.9	0.	55.2	0.	0.	0.	0.
2	PUMP STO	200.	322.9	0.	18.4	0.	0.	0.	0.
3	NUC 1	1200.	6479.9	53385.	61.6	0.	0.	0.	269995.
4	NUC 2	1000.	5155.7	42240.	58.9	0.	0.	0.	214823.
5	NUC 3	1300.	7665.5	50259.	67.3	0.	0.	0.	319398.
6	COAL 1	1000.	5526.3	73662.	63.1	0.	0.	2214370.	0.
7	COAL 2	600.	10069.1	192745.	38.3	0.	0.	5685901.	0.
8	COAL 3	600.	6596.5	39243.	62.8	0.	0.	2685127.	0.
9	COAL 4	400.	7404.3	100753.	63.4	0.	0.	3038724.	0.
10	COAL 5	200.	2094.6	29962.	59.8	0.	0.	902274.	0.
11	COAL 6	50.	385.3	7283.	22.0	0.	0.	150803.	0.
12	OIL 1	400.	477.0	24852.	13.6	0.	691023.	0.	0.
13	OIL 2	200.	795.1	44554.	9.1	0.	1180773.	0.	0.
14	OIL 3	200.	239.7	17372.	3.3	0.	369483.	0.	0.
15	OIL 4	200.	92.4	11441.	1.1	0.	149878.	0.	0.
16	CT 1	50.	1.3	137.	0.2	0.	3745.	0.	0.
17	CT 2	45.	4.9	494.	0.2	0.	13517.	0.	0.
18	CT 3	40.	6.7	635.	0.2	0.	17344.	0.	0.
19	CT 4	30.	2.1	185.	0.4	0.	5147.	0.	0.
20	CT 5	10.	1.1	95.	0.4	0.	2570.	0.	0.
21	EMER TIE	200.	2.3	326.	0.1	0.	6440.	0.	0.
FIRM PURCHASES									
1	PURCHASE	10.	14.0	350.					
FIRM SALES									
1	NEW SALE	20.	30.0						
2	SALE	200.	1200.0						

PRODCOST *** SAMPLE CASE ***

YEAR	COST MEGA\$	GWH REQD	GWH UN- SERVED	GAS BCF	GIL KBBL	COAL KTONS	NUKE GW-HRS	HRS LOST	CAP FAC
1980	709.	51445.	1.75	0.	4380.	13455.	19391.	18.3	42.27
1981	750.	53485.	0.82	0.	2440.	14717.	19301.	9.2	40.79

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3. D. S. Joy and R. T. Jenkins, *A Probabilistic Model for Estimating the Operating Cost of an Electric Power Generating System*, ORNL/TM-3549 (October 1971), p. 11.
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