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APPLICATIONS OF THERMAL ENERGY STORAGE TO PROCESS HEAT STORAGE AND RECOVERY IN THE PAPER AND PULP INDUSTRY

Final Report, September 1977—May 1978

By
J. H. Carr
P. J. Hurley
P. J. Martin

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Date Published

Work Performed Under Contract Nos. EC-77-A-31-1034
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Boeing Engineering and Construction Company
Seattle, Washington

DEPARTMENT OF ENERGY · UNITED STATES OF AMERICA

U. S. DEPARTMENT OF ENERGY

Division of Energy Storage Systems

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FINAL REPORT FOR THE PERIOD SEPTEMBER 1977 - MAY 1978

J. H. Carr, et al (B.E.C.)
P. J. Hurley(Weyerhaeuser)
P. J. Martin (S.R.I.)

BOEING ENGINEERING AND CONSTRUCTION COMPANY
SEATTLE, WASHINGTON

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PREPARED FOR THE
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Abstract

Applications of Thermal Energy Storage (TES) in a paper and pulp mill powerhouse were studied as one approach to the transfer of steam production from fossil fuel boilers to waste fuel ("hog fuel") boilers. Data from specific mills were analyzed, and various TES concepts evaluated for application in the process steam supply system. Constant pressure and variable pressure steam accumulators were found to be the most attractive storage concepts for this application. Performance analyses based on the operation of a math model of the process steam supply system indicate potential substitution of waste wood fuel for 100,000 bbl oil per year per installation with the accumulator TES system. Based on an industry survey of potential TES application, which requires excess base steaming capability, the results from the individual installation were extrapolated to a near-term (1980's) fossil fuel savings in the paper and pulp industry of 3.2×10^6 bbl oil/year. Conceptual designs of mechanical equipment and control systems indicate installed cost estimates of about $560,000 per installation, indicating an after tax return on investment of over 30%.

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1.0 INTRODUCTION AND SUMMARY

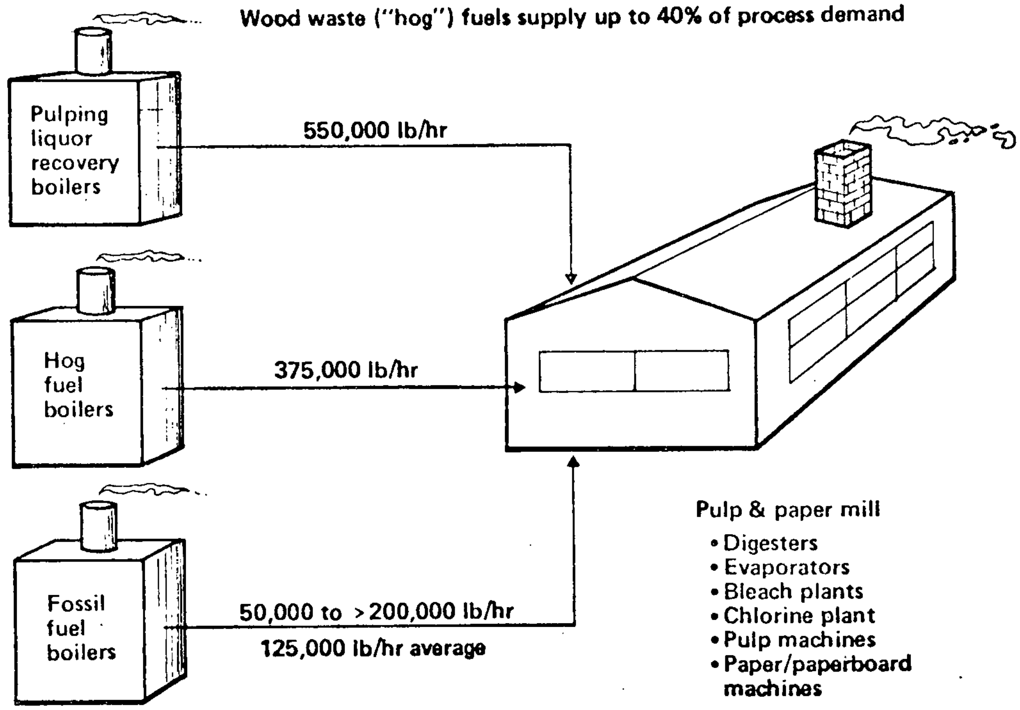
The purpose of D.O.E. in sponsoring this study has been, as expressed in PRDA CS AG 2000; to identify and verify:

- o The impact of thermal energy storage (TES) on the energy usage of various industrial processes in a variety of industries,
- o Potential TES device configurations,
- o The steps necessary to commercialize TES devices and achieve wide scale industrial applications.

The D.O.E. interest was not limited to new TES technology, but rather focussed on the objective of energy conservation whether achieved by new technology or new system applications of existing technology. In responding to the PRDA, Boeing Engineering and Construction (B.E.C.) selected the Paper and Pulp Industry for study. In consultation with the Weyerhaeuser Company, it was determined that a significant amount of fossil energy could be conserved if some of the fossil-fuel-generated steam typically required to meet the rapidly varying, or "swinging", process steam demand could be instead supplied by waste ("hog") fuel steam generating boilers.

Figure 1-1 illustrates this basic concept. In Figure 1-1A the steam supply for a typical pulp and paper mill is depicted. Although the largest portion of the total steam demand is supplied by the "base loaded" recovery and hog fuel boilers, a significant amount of fossil fuel is consumed to satisfy the "swinging" steam demand that occurs at rates beyond the response capability of the recovery and hog fuel boilers.

Paper & Pulp Industry Energy Supply Characteristics



Application of Thermal Energy Storage

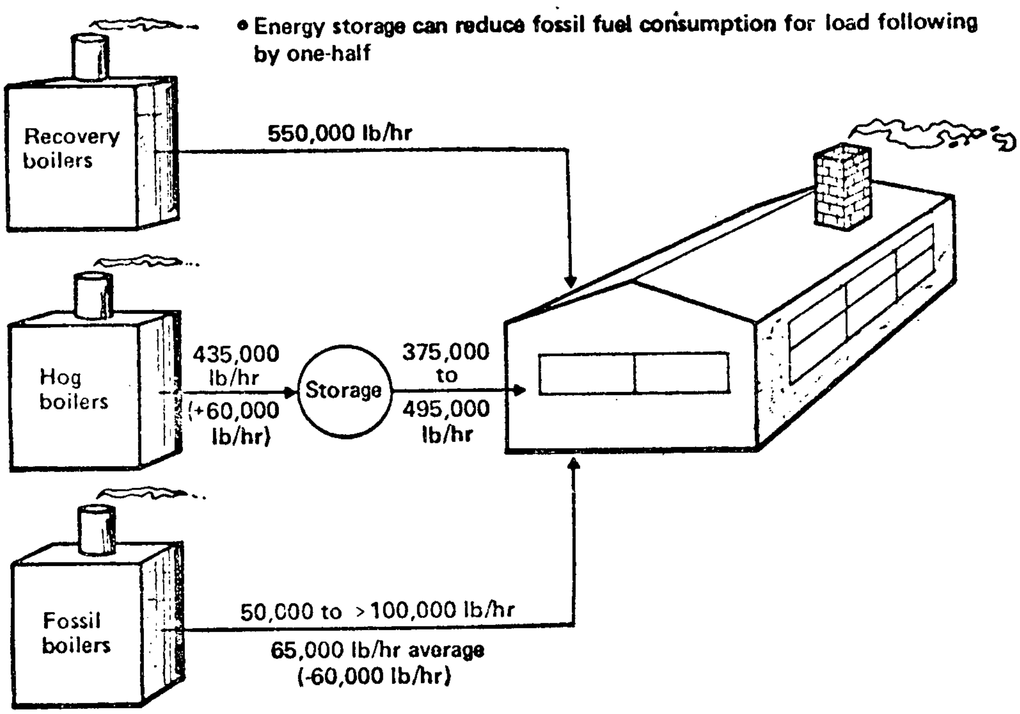


Figure 1-1. TES Application Concept

In Figure 1-1B, a TES system is used as a buffer between the hog boiler and the process demand, to permit the hog boiler to accept a portion of the swinging demand, and so relieve the fossil boiler of a large fraction of its previous average load. It should be noted that the fossil steaming rate cannot be reduced to zero by this means, since in practice, it is necessary to maintain a minimum steaming rate that will permit a rapid response to an extreme increase, or "upswing" in demand that would exceed the TES buffering capacity.

This simple concept was the basis for the study reported herein, and has been found to be both effective and practical.

1.1 STUDY APPROACH AND SCOPE

The approach employed to study the potential of TES for steam demand swing smoothing in the paper and pulp industry is represented in Figure 1-2. This approach utilized a specific mill--the Weyerhaeuser facility at Longview, Washington--to provide a basis for system analysis and conceptual design. The results of that analysis were then extrapolated on the basis of an industry survey to project the industry-wide impact of this TES application.

Implicit in this approach are a number of assumptions. For the Longview mill analysis, system operation was projected as that potentially feasible in 1980. Hence the study assumes the accuracy of estimated 1980 values for monthly average steam demand, baseload steam supply, electrical generation strategy, and performance capability of the hog fuel boiler with respect to maximum steaming rate, allowable frequency of firing rate changes, and maximum rate of change of steaming rate.

• Utilize TES for swing smoothing to permit substitution of hog for fossil fuel

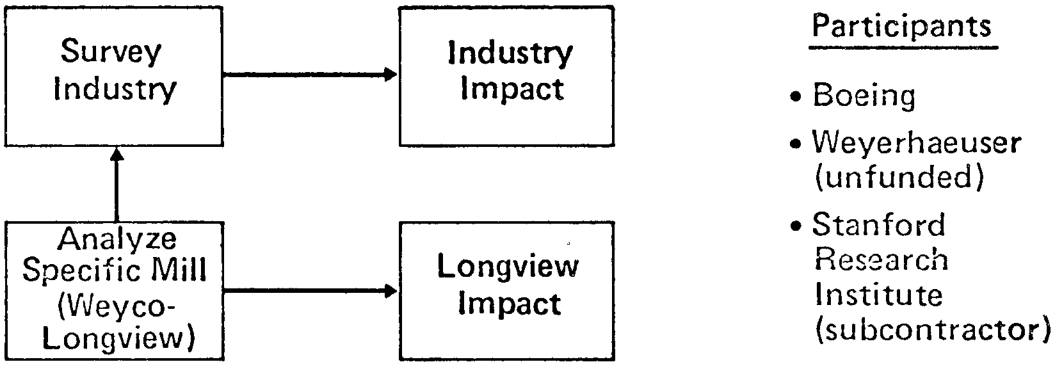


Figure 1-2. Study Approach

For the industry impact analysis it is assumed that the Longview mill is representative of the industry with respect to power plant configuration and steam demand swing characteristics.

The study was organized as four interrelated and sequenced tasks as illustrated in Figure 1-3. Weyerhaeuser had principal responsibility for data collection from the Longview mill and for the industry fuel use survey. Weyerhaeuser also assisted B.E.C. in math model development and size/performance trades. Stanford Research Institute was responsible for the Energy Resource Impact analyses of Task 3.

The scope of the study included consideration of both current- and advanced-technology TES concepts, and a number of system trade studies. Figure 1-4 indicates the range of TES candidates considered and summarizes the basis for selection of steam accumulators. Figure 1-5 lists the performance and economic trade studies performed in the study.

1.3 STUDY RESULTS

Fossil energy savings depend on (1) the performance of the TES system, (2) the frequency at which the hog boiler firing rate may be adjusted and (3), the availability of reserve hog fuel boiler steaming capacity to accept thermal load transfer from the fossil fuel boiler.

Figure 1-6 shows the performance of variable- and constant-pressure steam accumulator TES systems. For a minimum hog boiler change interval of 15 minutes (as estimated by Longview operations personnel), the indicated fossil

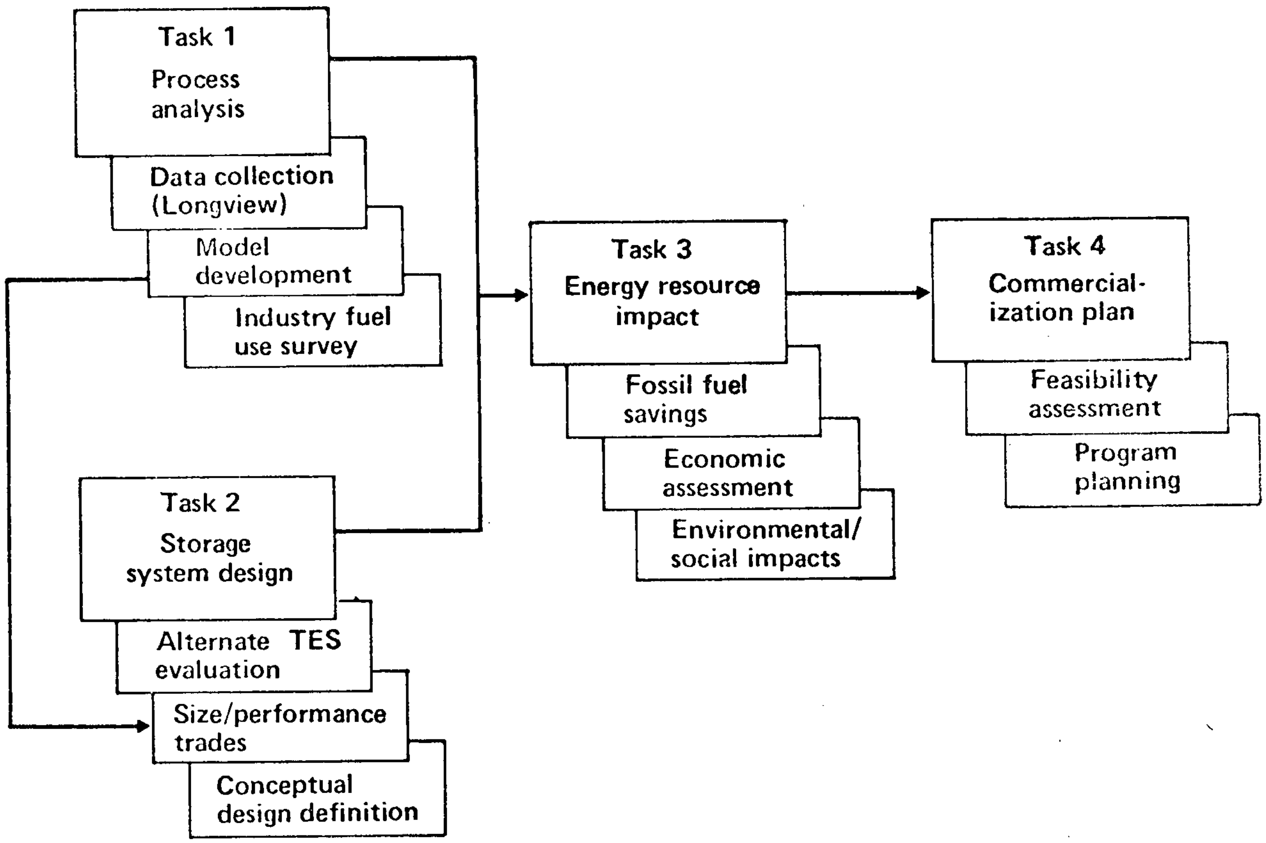


Figure 1-3. Study Organization

TES System Candidate	Development Status	Thermo-dynamic Interface	Operational Flexibility
Sensible heat - rock/oil	Development testing	Poor - viscosity problem	Adequate - max. rate fixed by H/X sizing
Sensible heat - rock/glycol	Variation of rock/oil concept	Adequate in concept	
Sensible heat - water	Fully developed - steam accumulators	Excellent	Excellent - can trade rate for time over large range
Latent heat - hydroxides	Component testing	Adequate in concept	Adequate - max. rate fixed by H/X sizing
Latent heat - other salts & metals	Developmental testing	Melt temp. too high	

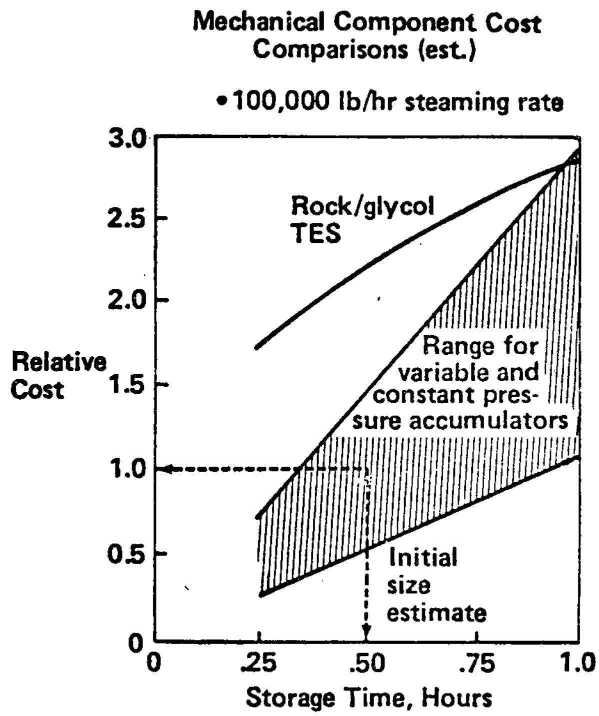


Figure 1-4. Storage System Candidates and Selection

- Industry & Longview performance:
  - Fossil/hog fuel consumption, electrical generation, vs.
    - Accumulator type, charge rate, storage capacity
    - Hog boiler change interval
    - System control law
  - Industry economics
    - After-tax R.O.I. vs.
      - Hog fuel cost
      - Average fossil/hog energy transfer
  - Longview economics
    - Annual operating savings vs hog fuel cost

Figure 1-5. Trade Studies

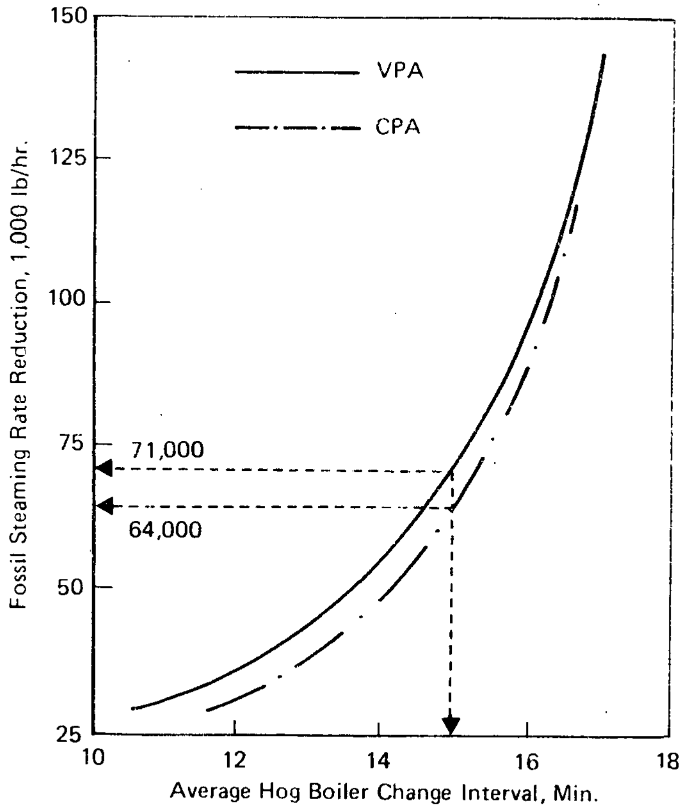


Figure 1-6. Steam Accumulator Performance

steam rate reductions of 64,000 to 71,000 lb/hr corresponds to fossil energy conservation in the order of 100,000 bbl oil per year at 80% availability.

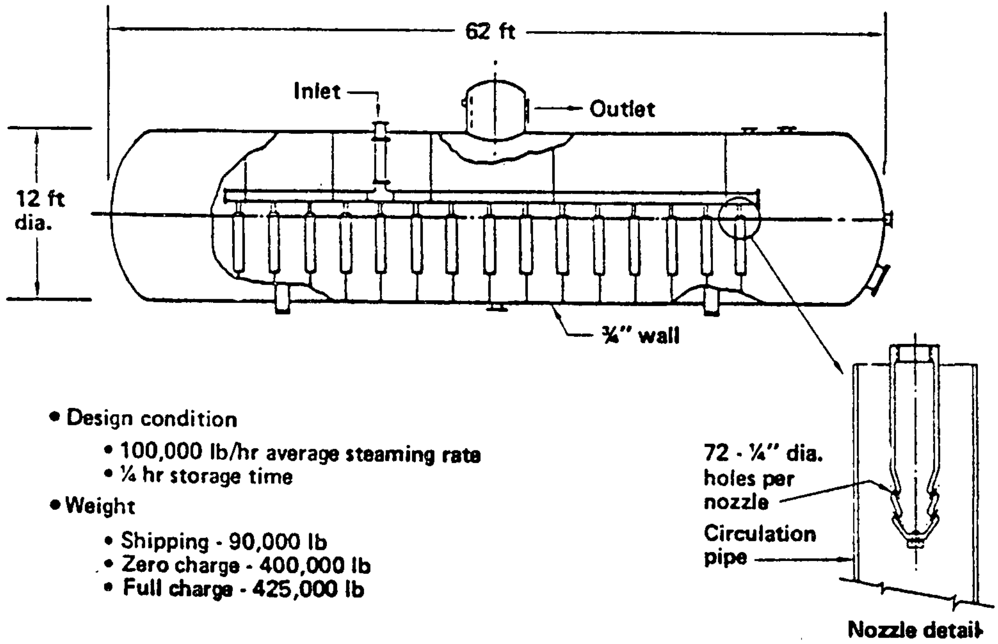
Conceptual design configurations of accumulators sized for this performance are shown in Figure 1-7. The variable pressure design is considerably larger than the constant pressure design, but does not require the separate de-aerating heater. System installation costs with either design are approximately $ 560,000 as shown in Figure 1-8.

Based on a survey of the industry, the near term potential for fossil energy conservation is in the order of 3 million bbl/yr, as shown on Figure 1-9. In the longer term--projected to the year 2000--fossil fuel conservation due to this application of TES could reach 18 million bbl/yr, as shown in Figure 1-10.

Installations of this type not only conserve fossil fuels, but appear very attractive as investment opportunities. As shown in Figure 1-11, an after-tax R.O.I. threshold of 15% is exceeded with marginal hog fuel prices as high as \$30/BDT (bone dry ton) (\$1.67/10^6 BTU) and annual-average thermal load transfers as low as 35,000 lb. steam/hr.

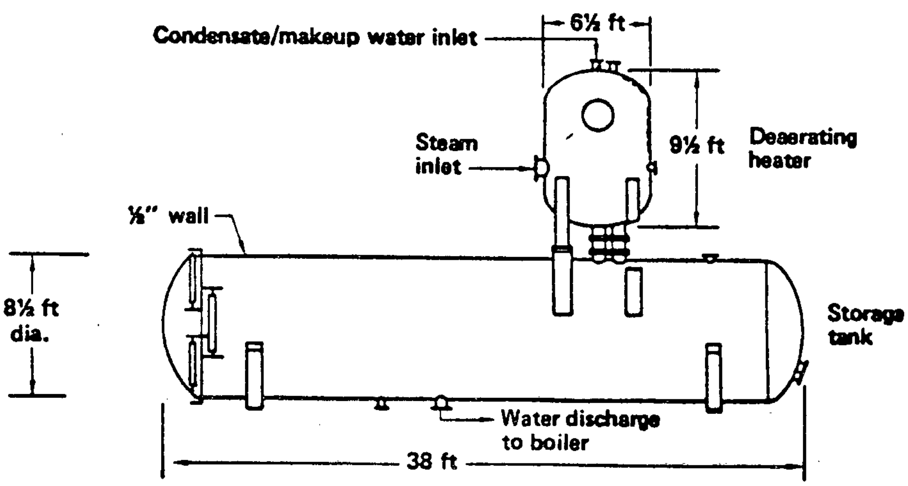
Because of the availability of all the required technology, commercialization of this TES application can proceed at a rapid pace. Figure 1-12 shows a schedule for commercialization that anticipates a demonstration system in operation within 18 months, followed by industrial implementation with commercial units coming on-line in less than three years.

140/40 psi Variable Pressure Accumulator Conceptual Design



- Design condition
  - 100,000 lb/hr average steaming rate
  - ¼ hr storage time
- Weight
  - Shipping - 90,000 lb
  - Zero charge - 400,000 lb
  - Full charge - 425,000 lb

140 psi Constant Pressure Accumulator Conceptual Design



- Design condition (single unit)
  - 75,000 lb/hr average steaming rate
  - .275 hr storage time
- Weight
  - Shipping - 40,000 lb
  - Zero charge - 50,000 lb
  - Full charge - 133,000 lb

Figure 1-7. TES Conceptual Design Summaries

Cost Account	140/40 psi Variable Pressure	140 psi Constant Pressure
Mechanical system		
Vessel & internal piping (1)	$ 72,000	$ 22,000
Deaerating heater (2)	N/A	52,000
Insulation (3)	20,000	8,000
Valves (3)	12,000	19,000
Feedwater pump (3)	N/A	7,000
Subtotal	$104,000	$108,000
10% Contingency	10,000	11,000
Total (FOB costs)	$114,000	$119,000
Field installation (typical) (4)		
Direct material	75,000	77,000
Direct labor	73,000	75,000
Freight, insurances, taxes, other indirects	114,000	118,000
Total mechanical systems	$376,000	$389,000
Control system (5)	$172,000	$172,000
Grand Total	$548,000	$561,000

(1) Based on vendor quotations (2) Based on vendor information (3) Engineering estimates
(4) Based on Guthrie's estimating factors for pressure vessel installations (5) Includes installation and test

Figure 1-8. Accumulator System Cost Estimates

Paper Industry Survey Summary

• Total mills with hog fuel/bark boiler capacity reporting to the American Paper Institute		117
• Number of mills contacted		55
• Number of mills with current fuel substitution potential		
12 months/year	6	
6 months/year	4	
Total equivalent, 12 months/year		8
• Number of mills with current programs that will result in fuel substitution potential by 1980		6
• Estimated average fossil/hog steam generation transfer potential		60,000 lb/hr
• Annual fossil fuel reduction potential at 1,100 BTU/lb steam, 80% boiler efficiency, 93% operating efficiency, 6.3×10^6 BTU/bbl		3.2×10^6 bbls

Figure 1-9. Near Term Fuel Substitution Potential

Impact of 10% shift in steam generation from gas/oil to solid fuels

Energy Source	1977 Consumption MMBTU/HR	Incremental Consumption by Existing Mills in Year 2,000, MMBTU/HR (No incremental elect. gen.)	(Max. incremental elect. gen.)
Pulping liquors	68,430	0	0
Hog fuel	36,451	+9,137	+11,059
Coal	12,974	+2,081	+2,647
Oil	50,155	-3,532	-3,532
Gas	33,971	-5,582	-5,582
Purchased electricity	23,895	0	-3,733
Annual Fossil Savings, MMBTU			
At the mills		79.8×10^6	79.8×10^6
At the utilities		–	32.7×10^6
Total		79.8×10^6	112.5×10^6
		(12.7 MM BBL)	(17.9 MM BBL)

Figure 1-10. Long Term Fuel Substitution Potential

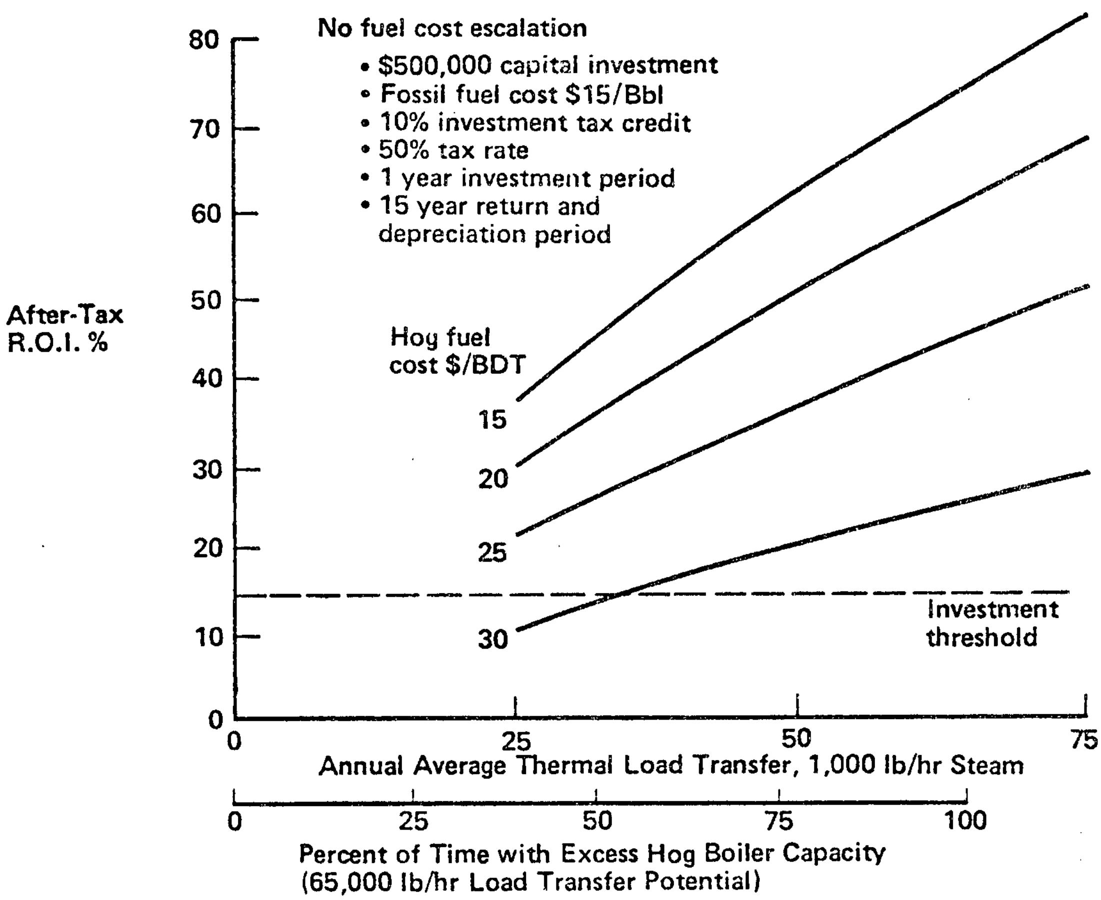


Figure 1-11. Return on Investment — No Incremental Electrical Generation

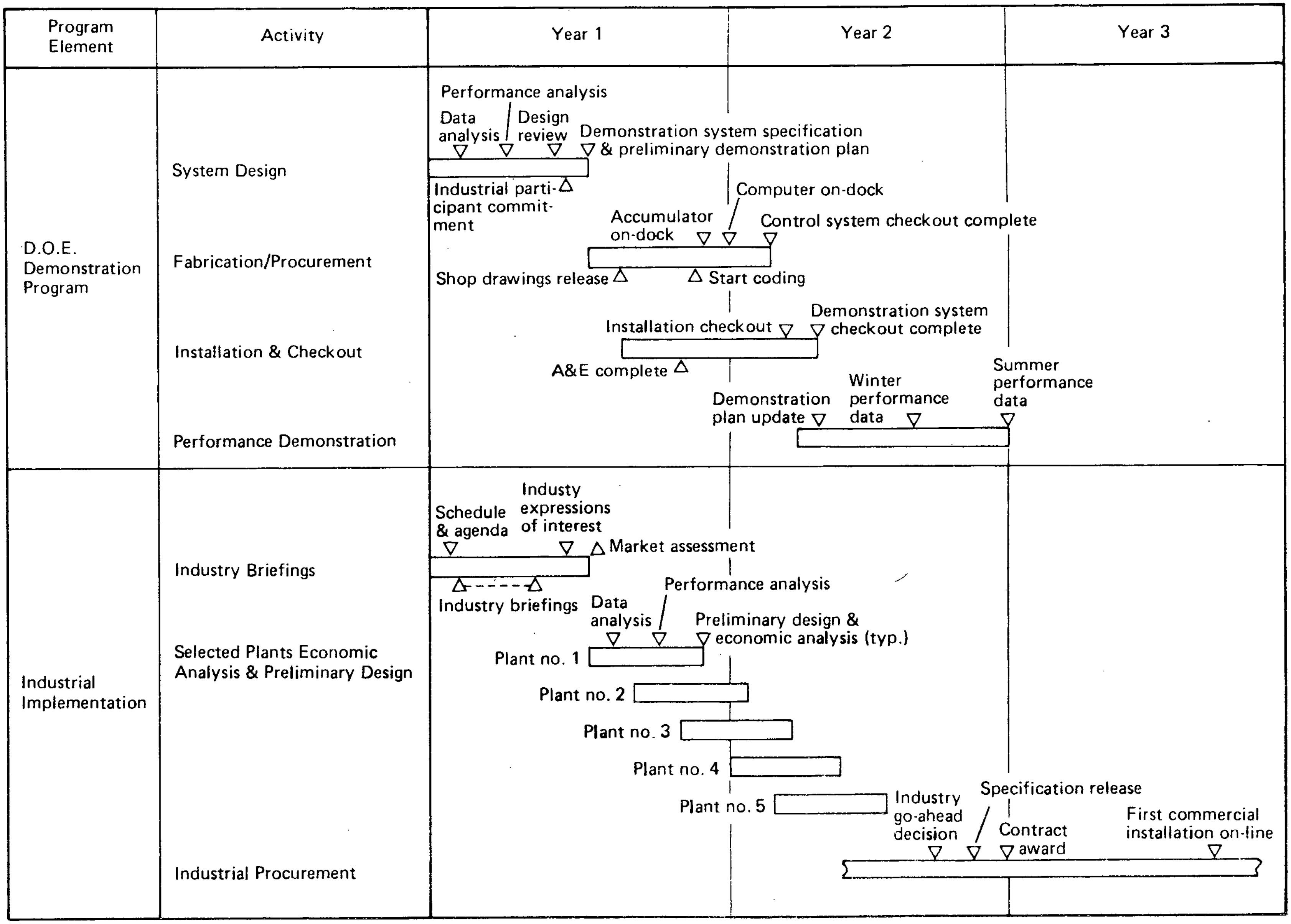


Figure 1-12 Commercialization Plan Activity Phasing

1.3 CONCLUSIONS AND RECOMMENDATIONS

As a result of this study, it is concluded that:

1. Provided hog fuel boiler capacity is sufficient to accept load transfer from the fossil fuel steam supply system, steam accumulator swing smoothing installations are desirable energy conservation measures in the paper and pulp industry.
   - Typical installations will permit fossil fuel savings in the order of 100,000 bbl/yr
   - These systems can be implemented today
   - Typical installations will provide an after-tax R.O.I. in the order of 30%.
2. Despite these positive findings, a demonstration program is probably required to stimulate rapid industrial implementation of this practical fossil energy conservation concept.
3. A demonstration program can be initiated immediately based on available technology.

Accordingly, it is recommended that D.O.E. proceed with the design, installation and operation of a demonstration system on an expedited basis.

2.0 PROCESS ANALYSIS

2.1 LONGVIEW PLANT CHARACTERISTICS

The energy requirements of the Weyerhaeuser Longview plant are dictated by the pulp mill process system steam demand and the electric power generation of the power plant. These energy requirements are time dependent and are met by a time-varying rate of boiler steam generation. The recovery/waste (liquor and hog fuel) boilers at Longview provide a base load of steam generation, while the oil/gas boilers basically provide the time dependent load. The primary goal of implementing use of a thermal energy storage device in Longview is to substitute additional hog fuel usage for some of the oil/gas fossil fuel consumption. This would be done by operating the hog fuel boiler at a higher base load, storing the excess steam when the demand is low, and discharging storage when demand is high. This system acts to increase baseload steam output by smoothing boiler steam demand swings.

The economics of steam swing smoothing in Longview depend upon the capacity of the swing smoothing system, and the number of hours per year that it will allow hog fuel substitution for fossil fuel. These two determinations are largely independent of one another, due to the variations in average steam demand through the year. Data necessary to size the smoothing system were drawn from four full sets of single day boiler steam flow charts. This swing data is considered to be independent of the time of year (Section 2.1.3).

Data needed to determine potential hours per year of fuel substitution were drawn from monthly average boiler steam flow data, and expected steam output from base loaded boilers (Section 2.1.2).

2.1.1 Power Plant Description

The Weyerhaeuser Longview plant selected as the model for the paper and pulp mill thermal energy storage study is typical of pulp mills where economic use of thermal energy storage is possible. The steam demand over the year is such that it is less than the capacity of the base loaded boilers a significant portion of the time. This allows for substitution of hog fuel for fossil fuel, a primary requirement for economic use of thermal energy storage. The amount of substitution is a function of the annual steam demand as well as the size and number of the steam demand transients (swings). The steam transients and the plant layout dictate the types of storage devices that can be considered, with the economics being determined by the integration of storage in the plant.

The plant is composed of a wood products operation and a paper and pulp operation. The two are essentially separate but either is able to supply energy to the other if desired. The study focused on the pulp and paper operation, where the steam demand is highly transient in nature. The paper and pulp operation consists of the process systems and the power plant, with the power plant supplying steam to the processes and the power generation turbines. In order to adequately determine the effect of thermal energy storage, it was necessary to model both the processes and the power plant. The processes were modeled by inputting header steam demand to the power plant model. The power plant was modeled on a component by component basis.

The power plant consists of a series of boilers, turbines, pressure reducing valves, desuperheaters, de-aerators, and condensers. Figure 2-1 is a plant schematic showing the relative location of these components. The layout is simplified from that of the actual plant in that all the desuperheating for the 40 psi and 140 psi headers is done at only single locations. The plant has 8 boilers currently in use, including one hog fuel boiler, three recovery boilers and four fossil fuel (oil/gas) boilers. One of the fossil fuel boilers is being modified to also burn waste hydrogen produced by the Cloralkali plant. The boilers operate at 600 psig with the exception of 1250 psig for the hog boiler. A summary of the boilers and their output is given in Table A-1, (Appendix A).

There are five turbine generators within the power plant. One is driven by 1250 psig steam from the hog fuel boiler. The other four are driven by 600 psig steam. All five provide steam for process loads, with this steam being at either 40 or 140 psi. Two of the turbines can also be run with condensers to generate more power, or take excess steam. A summary of the turbines, their ratings, and their bleed extraction capabilities is given in Table A-2 (Appendix A).

The 40 psig de-aerator is used as a feed water heater for the 600 psig boilers. The process condensate is returned to this de-aerator through condensate storage. Make up water is added as necessary to meet the demand. The 140 psig de-aerator is used as a feed water heater for the hog fuel boiler. Turbine condenser condensate and make up water supply this unit. The de-aeration and feed water heating is done with 140 psig steam. A summary of the data for the condensate and the two de-aerators is given in Table A-3 (Appendix A).

The desuperheaters are used to remove a portion of the superheat of the steam from the turbines and the steam going through the pressure reducing valves. A summary of the desuperheater and pressure reducing valves is given in Table A-4 (Appendix A).

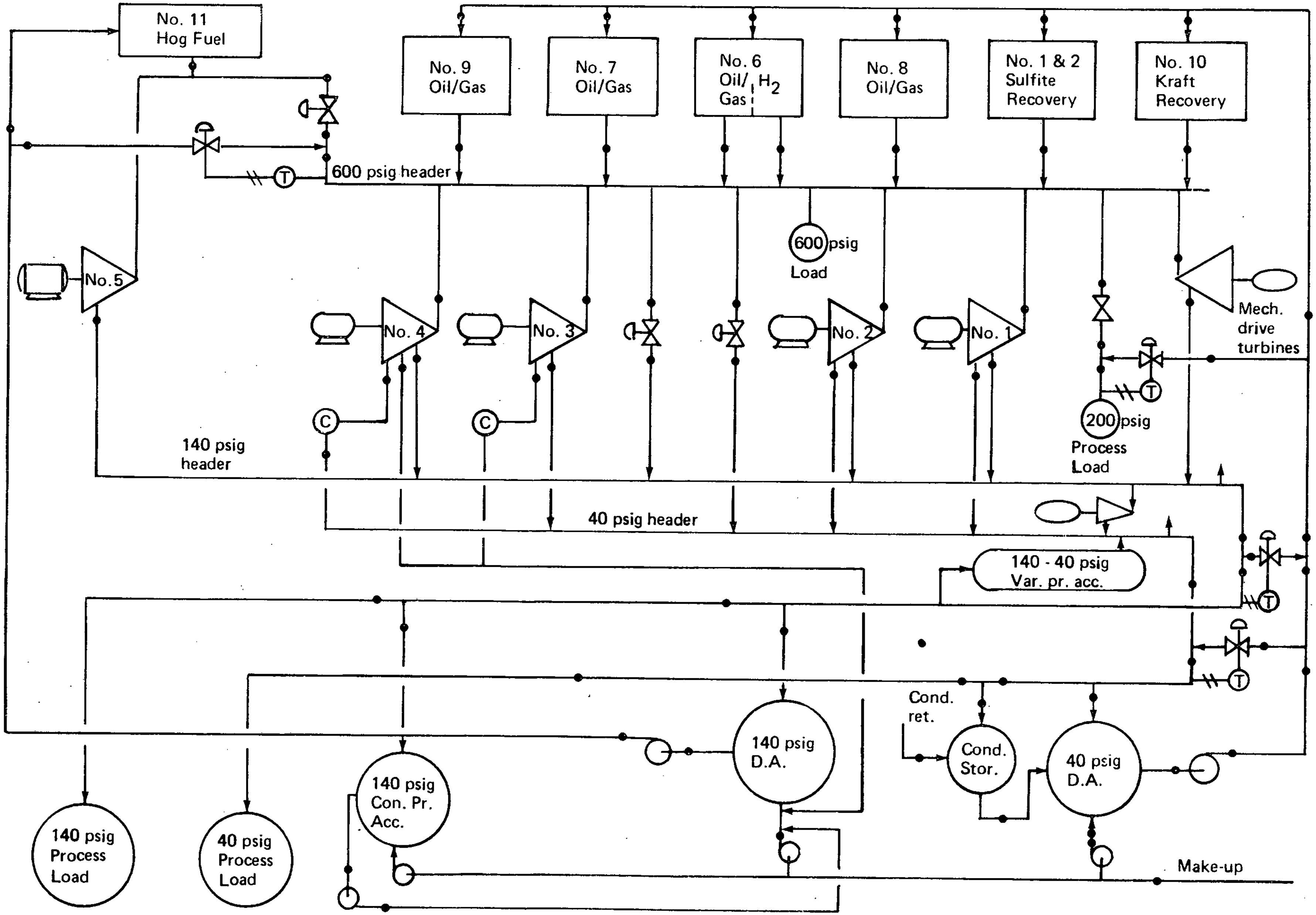


Figure 2-1. Longview Plant Schematic for Thermodynamic Model (With Storage)

The process loads are also depicted on Figure 2-1. The steam loads include 40 psig, 140 psig, 200 psig, and 600 psig process loads. There is also a 600 psig supply to the mechanical drive turbines, which exhaust to the 140 psig header. The 200 psig and mechanical drive 600 psig loads are either small or constant and are summarized in Table A-5 (Appendix A). The 40 and 140 psig loads and the steam requirements for electric power generation are discussed in Section 2.1.2. The 40 psig process steam loads are considered constant and are given in Table A-6 (Appendix A). The 40 psig deaerator steam demand is calculated in the model.

2.1.2 Average Steam Demand and Baseload Supply

The economic use of thermal energy storage/swing smoothing depends on the amount of time that it can be used. This is a function of the boiler capacity and the average hourly steam demand, which in turn is a function of the process steam demand and the electric power generation requirement.

Average boiler steam demand for the Longview plant is shown in Figure 2-2. It is based upon the monthly power plant boiler steam flow recorded at Longview, given in Tables A-7 and A-8, (Appendix A), corrected for electric power generation and steam flow to or from the sawmill. The sawmill steam flow, and the power generated are given in Table A-9.

The Table data is presented as received and not in a consistent set of units, with the steam being either in pounds or Btu's. The data was translated into a Btu energy demand and then converted into a 600 lb steam demand. A final adjustment was made to the data, reflecting an anticipated decrease of 30,000 lb/Hr in process steam demand in 1890.

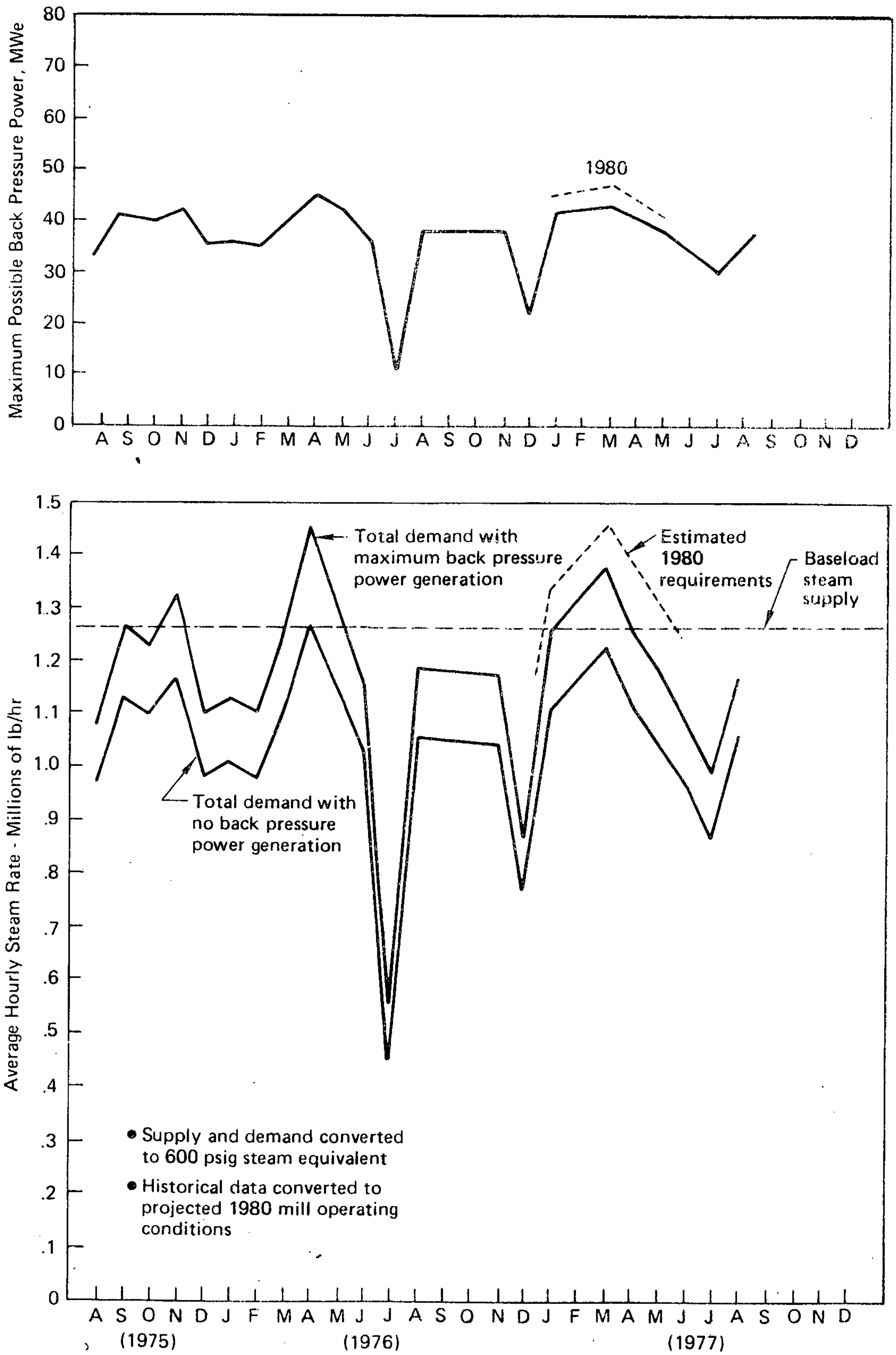


Figure 2-2. Longview Demand and Baseload Boiler Capacity

The net result of these corrections is a set of monthly points, indicating required steam flow from the pulp powerhouse boilers, with zero power generation and zero input or output to or from the sawmill. This is labeled as the no power generation steam flow on Figure 2-2. This data was then used to determine the additional steam flow required to generate the maximum back pressure power. This was based upon the boiler baseload steam flows and calculated steam loads given in Appendix A. In this case it was assumed that the hog fuel boiler was capable of its rating, with its full output run through the 1250 psig turbine. The result is the steam flow plot labeled "maximum back pressure power". The electric power generated under these conditions is also given in the top plot of Figure 2-2. A derivation of the equations used for the power generation analysis is given in Appendix A. The horizontal line across the figure shows the level of baseload steam output available. Table 2-1 lists the baseload steam sources and output.

2.1.3 Steam Swing Data

The source of steam swing data was a set of metered boiler steam flow charts for selected individual days. These charts showed the step changes in steaming rates of base loaded boilers, and the minute to minute changes in output from the load-following fossil-fired boiler(s). Table A-11 in Appendix A shows how key swing parameters for the individual days compare with the year-to-date average. Individual day chart data were composited to produce tables of swinging steam demand. This demand swing data incorporates the effects of changes in demand in all the headers, and uncontrolled changes in steam output from the hog fuel boiler. The tables for each of the four days are included in Appendix A.

TABLE 2-1

BASELOAD STEAM SUPPLY

BASELOADED BOILERS	CAPACITY OR NORMAL AVAILABILITY OF STEAM M#/HR
No. 1 and 2 Liquor	110
No. 6 on H_2	40
No. 10 Liquor	400
No. 11 Hog Fuel	550
No. 7 on fossil fuel with capability to swing downward by 75M#/HR	125
Sawmill excess (plywood not running 6 shifts/wk) if Norpac demand is 165 M#/HR	55
Total	1280

The model assumed that all swing demand change is occuring in the 140 psig and 600 psig headers, except that which occurs in the 40 psig header due to load following fluctuation at the 40 psig de-aerator.* This fluctuation was calculated within the model during the "base case" (non-swing smoothing) runs. Subtraction of this calculated change, and the tabulated 600 psig demand change, from the raw data resulted in a calculated change in 140 psig demand. Input to the subsequent swing-smoothing runs then consisted of this calculated 140 psig demand, and the previously tabulated 600 psig demand.

2.1.4 Present Plant Operating Strategy

Present operating strategy of the plant is strongly affected by the limitation in steaming rate imposed on No. 11 (hog fuel) boiler due to air emission control problems. These problems restrict the hog fuel boiler to rates that are 200 to 250 thousand pounds per hour below its design maximum. Consequently, the mill's fossil-fuel-fired boilers are operated at high rates, and the operator's ability to maintain header pressure control at reduced fossil firing rates has not been clearly established. Two or more fossil-fired boilers are maintained on line, with a combined swinging capacity of ± 200 to 250 M#/HR. Normally, one of these boilers will automatically change output to maintain 600 psig header pressure. The hog fuel boiler (No. 11), and the spent liquor boilers (No. 1, 2 and 10) are base loaded, and rarely change rates.

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*The extraction stage engines in No. 3 bleach plant impose a predictably cycling 40 psig steam demand of 8-9 M#/HR. The size of this swing did not warrant its separate treatment in the data.

Because the plant is unable to control process header pressure using automatic turbine controls, pressure reducing valves are used. Operators make settings on throttle and extraction valves of the turbines, and only change these when the PRV positions remain outside the desired ranges. The hog fuel boiler 1250psig header pressure is controlled by a PRV operating between this header and the 600 psig header, with the throttle of the 1250/140 psig turbine held fixed.

2.1.5 Future Plant Operating Strategy

Two facility changes are being planned within the plant. The first of these involves the base load firing of hydrogen produced at the site's clor-alkali plant, using No. 6 boiler. The second is the equipment addition needed to control air emissions from No. 11 boiler, to permit firing this unit at its maximum rate. Following these changes, the No. 5 turbine throttle will operate to control 1250 psig header pressure. No. 7 fossil fuel boiler, in addition to No. 6 boiler (firing hydrogen), would be on line, targeted to steam at 125 M#/HR, allowing a downswing of 75 M#/HR. A new hog fuel boiler rate control system would be expected to make changes on No. 11 boiler so as to maintain No. 7 boiler firing rate at its target average of 125 M#/HR. No. 6 boiler, on hydrogen, and the spent liquor boilers (No. 1, 2 and 10) would be base loaded and rarely change rates.

2.1.6 Alternate Swing Smoothing Systems

The Longview plant has turbine condenser capability that could be used for smoothing demand swings. Controls to allow maximum use of this capability are not available. Installation of controls would allow the condenser to absorb steam flow during demand downswings, while allowing the fossil boiler to meet the upswings. The economics of this type of plant operation depend on the values of electricity and hog fuel, and can be very attractive given the availability of turbine condenser capacity and electrical energy values typical of many parts of the country. However, the very low cost of purchased electricity and relatively high cost of hog fuel at the Longview plant make this approach uneconomical there, as discussed in Section 3.4.

2.2 STEAM PLANT MATH MODEL

2.2.1 Role of the Math Model in Process Heat Storage Study

The purpose of the steam plant math model is to examine the effect of thermal energy storage used for swing smoothing applications at the pulp and paper mill at Longview, Washington. It provides data useful in looking at both the economic and operational impacts of installing such a system.

The key area of economic concern is that of fuel substitution. The increased percentage of total steam demand that can be supplied by burning hog fuel, and the resultant decrease in the use of fossil fuel, is the major cost factor to be compared with system fabrication and installation costs. The amount of electricity generated in the plant will also be affected by the introduction of a thermal energy storage system and influence the economic calculations. Therefore, both fuel usage and electrical generation are required outputs of the steam plant math model.

The introduction of a thermal energy storage system into the mill will have an operational as well an an economic impact. As hog fuel is substituted for fossil fuel, the fossil fuel boilers will be steaming at a lower rate, and therefore, will have less capability to follow downswings in the process steam demand. This will cause the hog fuel boiler to change its rate more frequently. This makes the amount of fuel substitution versus frequency of hog fuel boiler change an important trade in the system studies. The model will provide information relating to the operation of the boilers (such as steaming rates and frequency and magnitude of rate changes) or to steam venting(such as the frequency and magnitude of venting events) as they will be important factors in the system selection process.

As well as aiding in determining the impact of a thermal energy storage system, the model serves as a major tool in conducting parametric studies. Independent variables such as storage device size can be varied over a wide range of values, and the model will produce the pertinent economic and operational data for each case.

2.2 MODEL ORGANIZATION

The steam plant math model is comprised of several subroutines, each serving a different function in the overall calculations. What follows is a list of these subroutines with a brief description of each.

MAIN controls execution of the program

INPUT reads and writes the values of the input variables

MASCON provides the master control logic (sets steam flows throughout the plant)

DEMAND determines the process steam demands

THERMO executes the thermodynamic calculations of mass flow and enthalpy for the plant and determines the hog fuel boiler steaming rate for the non-storage case

TESSUB calls the appropriate thermal storage subroutines and determines the hog fuel boiler steaming rate for storage cases

VPA accomplishes thermodynamic calculations necessary to model the variable pressure accumulator

FH140 models constant pressure accumulator thermodynamics

The computer program has been coded in standard IBM FORTRAN IV language using EBCDIC card format. The program consists of about 2000 cards, and is totally self-contained in batch execution.

2.2.3 Model Execution

The order in which the several program operations are executed can best be understood by following the steps indicated in Figure 2-3. First the program inputs are read and the process steam demands are determined by a table look-up procedure. Then approximate values for the de-aerator and desuperheater

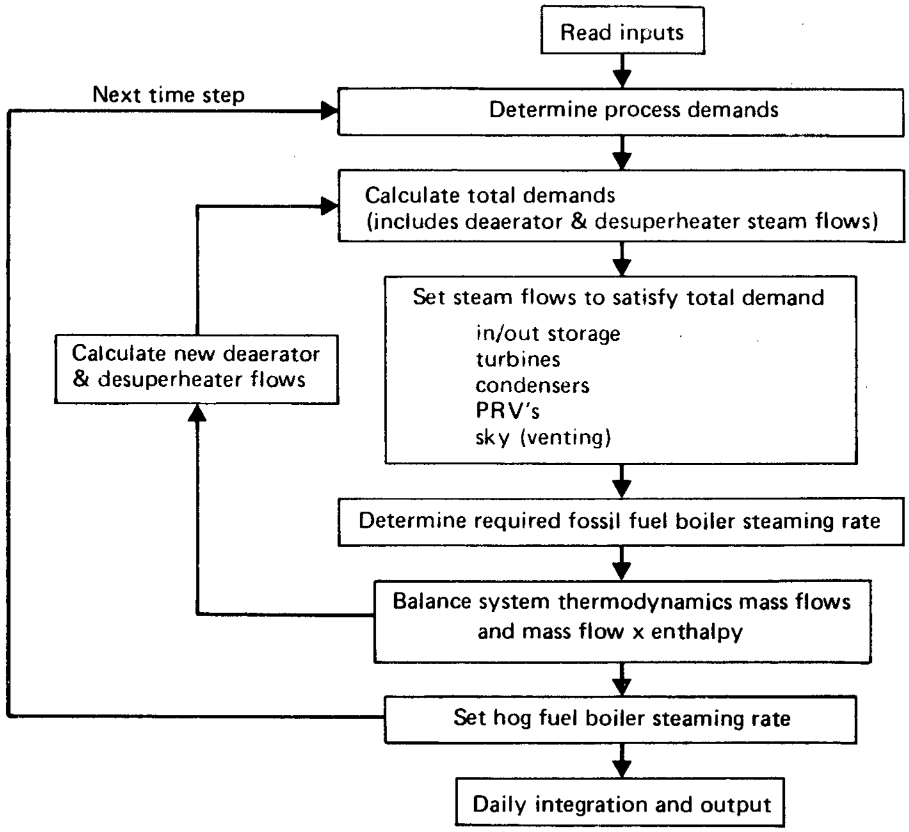


Figure 2-3. Industrial Process Heat Math Model Schematic

flows are added to the process demands to get the total demands. The exact values of these flows cannot be calculated until the flows through the rest of the system are determined. The fact that these other system flows are themselves dependent on desuperheater and de-aerator flows makes the model iterative in nature.

The model now determines the required valve settings throughout the plant to meet the total steam demand. It then calculates the rates at which the fossil fuel boilers must produce steam in order to satisfy these flows. The program now balances the thermodynamics by conservation of mass (steam mass flows) and conservation of energy (mass flow times enthalpy) equations. This will result in new values for the desuperheater and de-aerator flows, which are now used to get new total demands. This looping continues until the change in answers becomes smaller than a specified stopping value.

The next task is setting the hog fuel boiler steaming rate for the following time step. In non-storage cases, the hog fuel steaming rate is set so as to keep the fossil fuel boiler rates at a given value above their minimum (which will then be their downswing capability). In the cases where thermal energy storage is present, the hog fuel rate setting algorithm also considers the fullness of the storage device and whether it is filling or emptying. (See Section 2.2.10) The hog fuel boiler rate also takes into account whether steam is being vented to the atmosphere.

Once the hog fuel boiler steaming rate is set, process demand data for the next time step is used to begin the calculations once again. After the model has been run for a day's demand data, it integrates certain values over the day and prints out the desired output.

The following sections will present a more detailed view of each of the various program blocks.

2.2.4 Inputs

The model has the flexibility to simulate a variety of system configurations. Input variables are available to describe the plant layout. These inputs will indicate which boilers are operative, which turbines are on line, and what type of thermal energy storage device, if any, is present.

The majority of the inputs specify the performance characteristics of the devices in the steam plant. These include initial turbine flow rates, maximum and minimum condenser flow rates, maximum, minimum and initial boiler steaming rates, hog fuel boiler rate change capability, and storage device capacity.

Also specified in the input routine are the values of enthalpy throughout the system. These include enthalpy values of the steam leaving the boiler, steam leaving the turbines, make up water, process condensate return, and steam after desuperheating.

The final inputs are the process steam demands. These are given for each of four classes (40, 140, 200 and 600 psig demands) as a function of time. By changing these values, the model can be run for any day for which demand data exists.

2.2.5 Control Logic

As discussed earlier, the model combines the values for total steam demands and the device characteristic inout to arrive at the prooer settings for the many steam flow valves in the plant. The logic utilized in calculating these settings is presented in Figure 2-4. This chart represents the control logic applicable to a plant which includes a variable pressure accumulator between the 140 psig and 40 psig headers. The model goes through the sequence of first balancing the steam flow on the 140 psig header (matching supply and demand) then the 40 psig header, and finally the 600 psig header (matching total boiler supply and demand).

2.2.6 Thermodynamic Analysis

The model uses a nodal represenation of the steam plant in order to accomplish the thermodynamic balancing calculations. The program contains a series of equations which give the mass flow and enthalpy at a given node as a function of mass flow and enthalpy values for previously computed node points. The current model has 122 such node points. Figure 2-1 shows the steam plant as simulated by the math model. It includes 7 boilers, 6 turbines, 2 condensers, 4 process demands, 4 pressure reducing valves, 3 desuperheaters, and 2 de-aerators. Also pictured are both the variable pressure and constant pressure

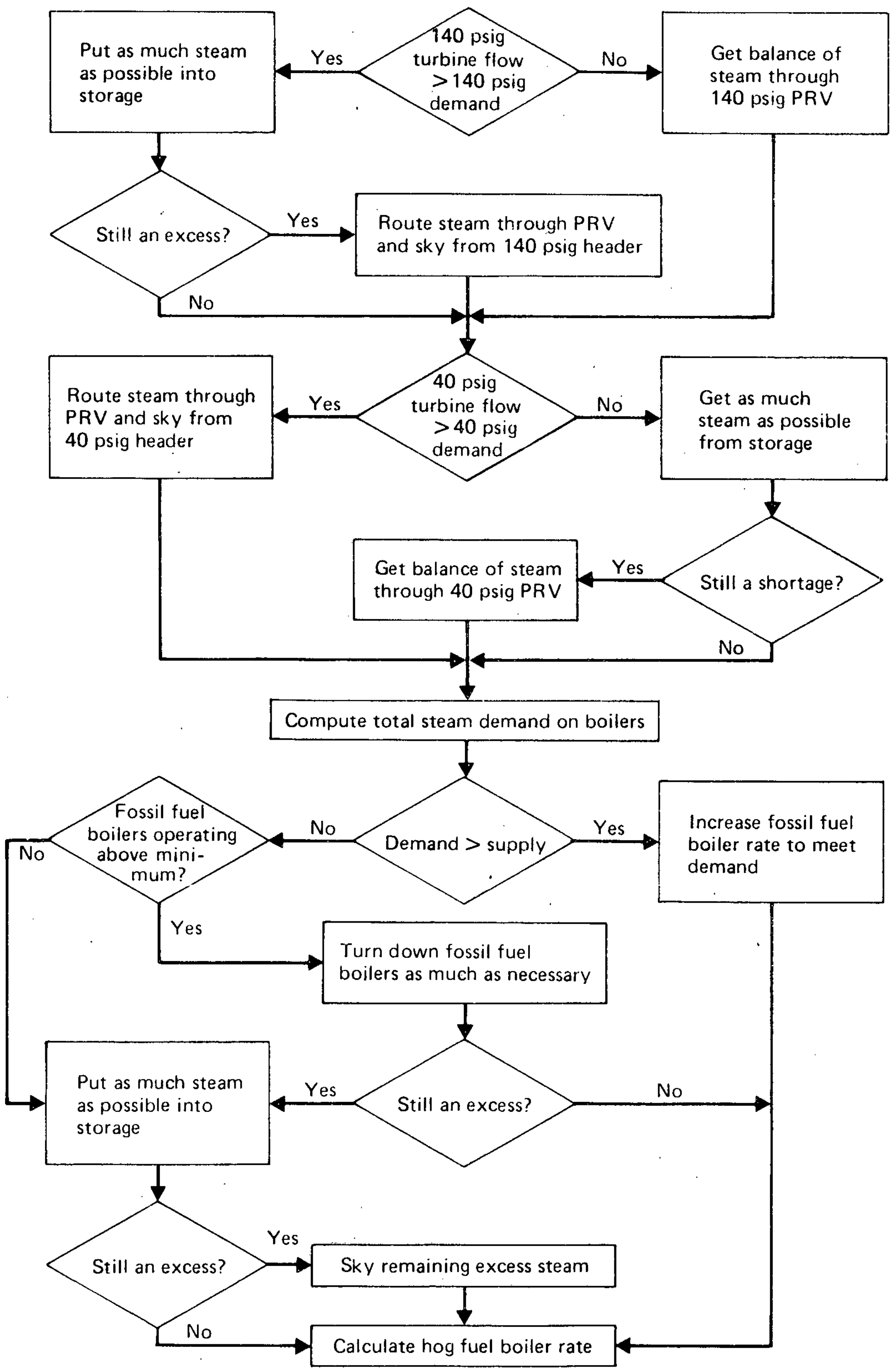


Figure 2-4. Control Logic (Variable Pressure Accumulator)

accumulators, though the model is not organized to handle a system containing both devices at once. The turbine thermodynamic calculations also yield figures for plant electrical production.

2.2.7 Outputs

For each time step the model prints the values of the steam mass flows for several key points in the plant. These are the boiler steaming rates, turbine inlet rates, PRV flows, steam flows into the de-aerators, storage charging and discharging rates and steam flows through the safety valve (venting).

After writing this time step data the model prints the daily integrated output. These values are the total steam production from each boiler, the total electrical production from each turbine, the total amount of steam vented (and the total duration of venting events), and the number of times the hog fuel boiler changed its steaming rate.

2.2.8 Study Approach

Before the model could be used to run parametric studies of thermal energy storage devices, its accuracy in representing the steam plant had to be checked. For this reason, a verification case representing current plant operating strategy and performance limitations was constructed.

At the present time, the hog fuel boiler, although designed to produce steam at a maximum rate of 550,000 pounds per hour, is limited to a steaming rate of 300,000 pounds per hour due to environmental restrictions. This requires the fossil fuel boilers to contribute to the baseload steam production.

The verification case used known boiler steam production values from plant recording charts to derive process demand data. The plant performance as predicted by the model was reviewed by Longview plant supervisory personnel. The steaming rates of the fossil fuel boilers, the flows through the pressure reducing valves, the amount of steam skying, and the amount of electricity produced all agreed with the expected response to the given demand swings. Now that the model was validated, it was updated to assume a 1980 operating strategy. Since this would be the time when a thermal energy storage device could be introduced at Longview, storage systems had to be compared to a non-storage system operating during the same period. The key improvement assumed in the plant, from the verification case, is the ability of the hog fuel boiler to be operated at its maximum steaming rate and to change its rate without violating environmental standards.

The process demands calculated in the verification runs were used as input to these studies. The hog fuel boiler rate setting algorithm adjusts the hog fuel boiler steaming rate so as to keep the fossil fuel boilers at a targeted amount above their minimum rate. This then is the downswing capability of the fossil fuel boilers. The model was run for several fossil fuel boiler target rates. Higher rates gave greater swing following capability to the fossil fuel boilers, resulting in less skying and less hog fuel boiler rate changes, but caused greater consumption of fossil fuel. These parametric results then served as the base case for comparison with candidate storage system configurations.

The storage device analyses involved studying both constant and variable pressure accumulators. A range of accumulator sizes and control philosophies were examined. The parametric results could then be compared for the storage cases and the base case.

2.2.9 Operation with Storage

The flow of information between the Industrial Process Heat Model (IPHM) and the storage algorithms is represented in Figure 2-6. At the appropriate point within the thermodynamic calculations of IPHM (i.e., within the THERMO subroutine), program control is passed to the TESSUB Subroutine. This subroutine has a dual purpose: (1) to call the appropriate thermal energy storage subroutine based on the storage alternative selected; and (2) to calculate the HFB firing rate goal. Originally, there were as many as five storage alternatives, however, initial economic and performance evaluations led to the selection of the variable pressure accumulator (IALT = 2) and constant pressure accumulator (IALT = 3). As shown in Figure 2-5, program control passes through TESSUB to either VPA or FH140 accomplishing TESSUB's first purpose. After thermodynamic calculations are made in VPA and FH140, control passes back to TESSUB to perform the second purpose before returning to IPHM. The thermodynamic calculational basis of VPA and FH140 is described in the following paragraphs:

VPA

The VPA subroutine accomplishes the thermodynamic calculations necessary to model the behavior of the variable pressure accumulator. Conservation equations for mass and energy are given by:

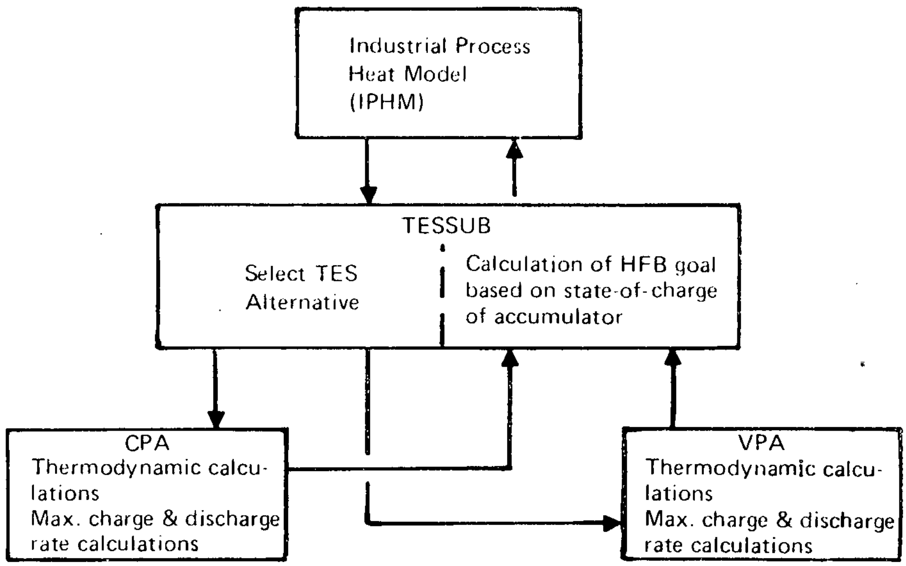


Figure 2-5. Information Interface Between IPHM and Storage Algorithms

$$\text{(mass)} \quad \frac{dm_f}{dt} = \frac{dm_{g,c}}{dt} - \frac{dm_{g,d}}{dt} \tag{2-1}$$

$$\text{(energy)} \quad d(m_f h_f) = \left(h_{g,c} \frac{dm_{g,c}}{dt} - h_{g,d} \frac{dm_{g,d}}{dt} \right) dt \tag{2-2}$$

where m, h, t refer to mass, enthalpy and time, respectively. The subscripts have the following connotations:

$(\ )_f$ = fluid, i.e., water

$(\ )_g$ = gas, i.e., steam

$(\ )_c$ = charging mode

$(\ )_d$ = discharging mode

The assumptions made in the analysis are:

1. Perfect mixing of steam and water:

   $$h_{g,c} = h_{g,d} = h_g \tag{2-3}$$

   This assumption neglects the slight superheat of the charging steam. The superheat content is about 15 BTU/lbm as compared to approximately 1200 BTU/lbm for the saturated steam.

2. The water is calorically perfect, i.e.:

   $dh_f = c_p dT$ where c_p is treated as a constant over the temperature range experienced (360^0 - 290^0F)

3. The latent heat of vaporization of the water can be expressed as

$$h_{fg} = h_f - h_g = a + bT + cT^2 \tag{2-4}$$

where a, b, and c determined by a nonlinear regression curve fit to Steam Table data, e.g., a = 1060.54, b = -0.249, c = -0.00034

4. The charge rate, $\dot{m}_{gc}$, and/or the discharge rate, m_{gd}, can be considered constant over the given time step, Δt.

$$m_f = (\dot{m}_{g,c} - \dot{m}_{g,d})\Delta t + m_{fo} \tag{2-5}$$

Combination of the above assumptions with the conservation equations yields straighforwardly after integration to the following governing equation for the VPA:

$$\tanh^{-1}\left\{\frac{2cT_2+b}{\sqrt{b^2-4ac}}\right\} = \tanh^{-1}\left\{\frac{2cT_1+b}{\sqrt{b^2-4ac}}\right\} - \frac{\sqrt{b^2-4ac}}{2c_p}\left\{\ln\frac{(\dot{m}_{gc}-\dot{m}_{gd})\Delta t+m_{fo}}{m_{fo}}\right\} \tag{2-6}$$

Given the initial state of the accumulator, the steam enthalpy above the water surface is known, therefore, by a table lookup function, the initial temperature T_1 is known. The governing equation then shows that T_2 is functionally related by:

$$T_2 = fn(T_1, \dot{m}_{gc}, \dot{m}_{gd}, m_{fo}, \Delta t)$$

Once T_2 is so determined, h_{g2} is tabularly related to T_2. Comparisons based on a daily energy balance between the Base Case and VPA operating as described above show agreement within 0.6%.

FH140

The FH140 subroutine provides the modeling of the constant pressure accumulator. Since the pressure, and therefore, temperature in the accumulator is maintained at 140 psig, only conservation of mass is required,

$$m_f = (\dot{m}_{gc} - \dot{m}_{gd})\Delta t + m_{fo} \tag{2-7}$$

The constant pressure accumulator "provides" additional steam by supplying preheated feedwater to the 140 psig de-aerator, thereby decreasing the requirement for 140 psig steam to meet the heated feedwater requirements of the hog fuel boiler. The accumulator thus can only "provide" steam up to the amount that would have been used by the de-aerator. Since the amount of steam which would have been used by the de-aerator varies as the hog fuel boiler steaming rate, the steam "swinging" capability of the CPA is at a maximum at the hog fuel boiler maximum steaming rate and at a minimum at the minimum HFB steaming rate.

Since the condenser return also flows into the 140 psig de-aerator, not all of the 140 psig steam can be removed in periods of high 140 psig demand. A minimum amount of 140 psig steam is required to reheat the condenser return flow. In order to calculate the flow of preheated feedwater from the constant pressure accumulator to the de-aerator, the de-aerator thermodynamic calculations are anticipated in FH140. The amount of steam that would be required from the 140 psig header without flow from storage is given by:

$$\dot{m}_s = \frac{(h_b - h_{fw})\dot{m}_b - (h_c - h_{fw})\dot{m}_c}{(h_s - h_{fw})} \qquad (2\text{-}8)$$

where

$(\ )_b$ = boiler feedwater flow

$(\ )_c$ = condenser flow

$(\ )_{tw}$ = cold feedwater flow

$(\ )_s$ = 140 psig steam flow

The minimum amount of 140 psig steam is given by:

$$\dot{m}_s' = \frac{(h_b - h_c)}{(h_s - h_b)} \dot{m}_c \qquad (2\text{-}9)$$

The difference $(\dot{m}_s - \dot{m}_s')$ represents the maximum steam that the CPA can "provide" by the decreased need of 140 psig de-aerator steam.

Comparisons based on a daily energy balance show the Base Case and operation with a CPA agree to within 0.2%.

2.2.10 Hog Fuel Boiler Firing Rate Control Logic

The firing rate of the hog fuel boiler was controlled by the state of charge of the storage device. In general, the hog fuel boiler (HFB) firing rate was controlled to maintain storage at a given target value of charge. The selected target value was at the point where storage could equally accept the design steaming rate in a charge mode or deliver steam in a discharge mode for half the design storage time. For example, an accumulator designed for a steaming rate of 100,000 lbm/hr and a storage time (full to empty) of 0.5 hour would have, at the target value, the ability to accept or deliver 100,000 lbm/hr for 15 minutes.

For the constant pressure accumulator, the state of charge was expressed as an inventory value, I, given by the ratio of the mass of water in the accumulator to the maximum mass that would be placed in the accumulator, i.e.,

$$I_{CPA} = \frac{m_w}{m_w\big|_{MAX}} \tag{2-10}$$

The variable pressure accumulator inventory value was based on the enthalpy value of the saturated steam stored above the water surface, h_s, i.e.,

$$I_{VPA} = \frac{h_s - h_L}{h_u - h_L} \tag{2-11}$$

Where: h_L = enthalpy at lowest pressure, i.e., "empty" point = 1179 Btu/lbm at 50 psig

h_u = enthalpy at highest pressure, i.e., "full" point = 1195 Btu/lbm 140 psig

The value of I for the target value as defined above for the two accumulators was:

$$\begin{aligned} I_{TAR}\big|_{CPA} &= 0.500 \\ I_{TAR}\big|_{VPA} &= 0.556 \end{aligned} \tag{2-12}$$

(The target value for the VPA is different owing to the nonlinearity of the storage density of a VPA with pressure. This point is demonstrated in the section of the report dealing with sizing of the storage device, Section 3.3.1).

The general philosophy behind the HFB rate control was to use storage in such a manner as to lessen the requirement for frequent HFB rate changes. That is, imbalances in steam demand were met by the utilization of storage, if possible, before changes in the hog fuel boiler rate were called for. This philosophy was implemented in the industrial process heat math model by calculating a goal for the hog fuel boiler firing rate at each time step. This goal was based on the storage inventory value. The actual hog fuel boiler firing rate was changed to approach that goal only when either the minimum hog fuel boiler change time had elapsed or a skying event had occurred. The hog fuel boiler firing rate was assumed to change at 50,000 lbm/hr per minute.

The control logic is described in the following steps:

1. After the appropriate thermodynamic calculations are made corresponding to the accumulator type, the inventory value is formed according to either equation (2-10) or (2-11). The inventory value for the current I_1, and the past, I_2, time steps are stored.
2. The difference between the inventories corresponding to the current and the past time steps and the difference between the current inventory and the target inventory are formed:

$$\Delta_{AVG} = I_1 - I_2$$
$$\Delta_{TAR} = I_1 - I_{TAR} \qquad (2\text{-}13)$$

3. If the inventory is increasing ($\Delta_{avg}>0$) and is above target ($\Delta_{tar}>0$), the goal for the HFB firing rate is set below the current HFB firing rate. The change in the HFB firing rate, Δ_{chng}, is calculated based on the difference Δ_{avg}.
4. If $\Delta_{avg}>0$ and $\Delta_{tar}>0$ and $I_1>0.85$, the control logic senses that the storage device could possibly become full in the next few time steps. Therefore, the HFB firing rate change, Δ_{chng}, is recalculated based on the difference from target, i.e., Δ_{tar}.
5. If inventory is increasing ($\Delta_{avg}>0$) but is below target ($\Delta_{tar}<0$), the inventory is approaching the target as desired so that no HFB change is required, $\Delta_{chng} = 0$.
6. If the inventory is increasing ($\Delta_{avg}>0$) but a skying event is occurring, the HFB attempts to change its rate immediately by the larger of the skying amount or the change as calculated above.
7. If the inventory is decreasing ($\Delta_{avg}<0$) and is below target ($\Delta_{tar}<0$), the goal for the HFB firing rate is set above the current rate, Δ_{chng} based on Δ_{avg}.
8. If $\Delta_{avg}<0$ and $\Delta_{tar}<0$, but $I_1<0.15$, Δ_{chng} is based on Δ_{tar}
9. If $\Delta_{avg}<0$ but $\Delta_{tar}>0$, $\Delta chng = 0$.
10. If simultaneously with any of the above calculated HFB changes, Δ_{chng}, the fossil fuel boiler has been firing on the average over the past 15 minutes by an amount above its minimum (50,000 lbm/hr) which is larger in magnitude than Δ_{chng}, the goal for the hog fuel boiler will be increased by the average amount the fossil fuel boiler has been firing over minimum.

11. If the accumulator is "empty" ($I_1<0.01$) when the HFB rate change is implemented, an additional 160,000 lbs/hr is added to the goal.

12. All goals for the HFB are caused to be at least the minimum HFB firing rate (200,000 lbs/hr) and at most the maximum HFB firing rate (550,000 lbs/hr).

2.3 INDUSTRY SURVEY

A primary objective of the study was to estimate the extent to which thermal energy storage could reduce fossil fuel consumption within the whole pulp and paper industry, through increased substitution of hog fuel. Identification of mills where this substitution could be aided by storage was the purpose of the industry survey. The source of the initial survey data was the American Paper Institute, a pulp and paper trade association with broad membership. The API receives energy use data from its member mills, and acts as spokesman for the industry on energy affairs.

A request was made to API for detailed energy use data from all U.S. mills consuming hog fuel. Analysis of this data was intended to allow screening of the mills into high and low substitution potential groups. Followup telephone contacts with the high potential mills were planned. However, due to the confidential nature of the API/member-mills relationship, this detailed data could not be released. Instead, the API supplied the names and locations of reporting mills burning bark and hogged fuels. The listing of these mills followed a ranking criterion that was intended to cluster high potential mills near the top of the list. This ranking criterion was the ratio of highest to lowest quarterly hog fuel consumption in 1976. The rationale that led to selection of this criterion was that, as plant steam demand varied with weather conditions, those plants whose hog fuel generated steam output varied with total demand would show the largest variations in hog consumption. The usefulness of this screening attempt was tested in the survey by contacting mills from the top, middle and bottom of the list. Candidate mills for storage application were found to be equally distributed among the three groups, indicating insensitivity to the ranking criterion, and requiring a larger sampling in the survey.

The 117 hog fuel burning mills reported by API are listed in Appendix B-1. An asterisk indicates mills contacted (55) in the telephone survey. The telephone survey was directed at the steam plant superintendant in each mill. Each superintendant was asked whether fossil fuel was fired in his plant to follow swinging steam demand, while hog fuel boilers were operated below capacity. Those responding yes were included as candidates for swing smoothing systems. Months per year of required slowdown, and size of downswing to be absorbed were also determined.

Several mills reported that new boilers were being installed, or plant changes were being planned which were expected to result in hog slowdown and fossil firing for swing following. These were also included in the number of candidate mills.

Of the 55 mills contacted, 6 were in the hog slowdown situation for the whole year; 4 were in it half the year; and 6 expected to be in it before 1980 due to planned changes. Average swinging demand to be absorbed in these plants was $\pm$ 60,000 LB/HR. Extrapolation of this sampling to the full list indicates the full potential fossil fuel savings resulting from swing smoothing to be 3.2 million BBLS of oil per year. Appendix B detailed the savings calculation and selected survey details.

3.0 STORAGE SYSTEM DESIGN

The Longview mill has a variety of boiler types and steam usage requirements resulting in steam demand of differing pressures. A number of possible system alternatives where TES could be employed were available. Involved in the storage system design has been the identification of those process system alternatives which were most attractive for the integration of a TES system. Selection of storage concepts applicable to the process system alternatives were chosen. The baseline storage concept(s) consist of the preferred TES concept(s) as applied to the preferred process system alternative(s). Trade studies were performed on the baseline storage system concept defining the effect of design variables such as size on system performance. Finally, the mechanical and control system conceptual designs were made on the selected baseline storage system size. The following paragraphs present the results of the above process.

3.1 PROCESS ALTERNATIVE AND TES CONCEPT SELECTION

Based on the data for the Longview process steam system as presented in Section 2.1, four potential process alternatives were identified as having potential for TES integration. Those process alternatives are given below and are illustrated in Figure 3-1:

1. Feedwater heating using 140 or 40 psig steam
2. Charging storage from 140 psig header; discharging to 40 psig header.
3. Charging storage from 600 psig header; discharging to 140 psig header.
4. Charging storage from 600 psig header; discharging to 200 psig header.

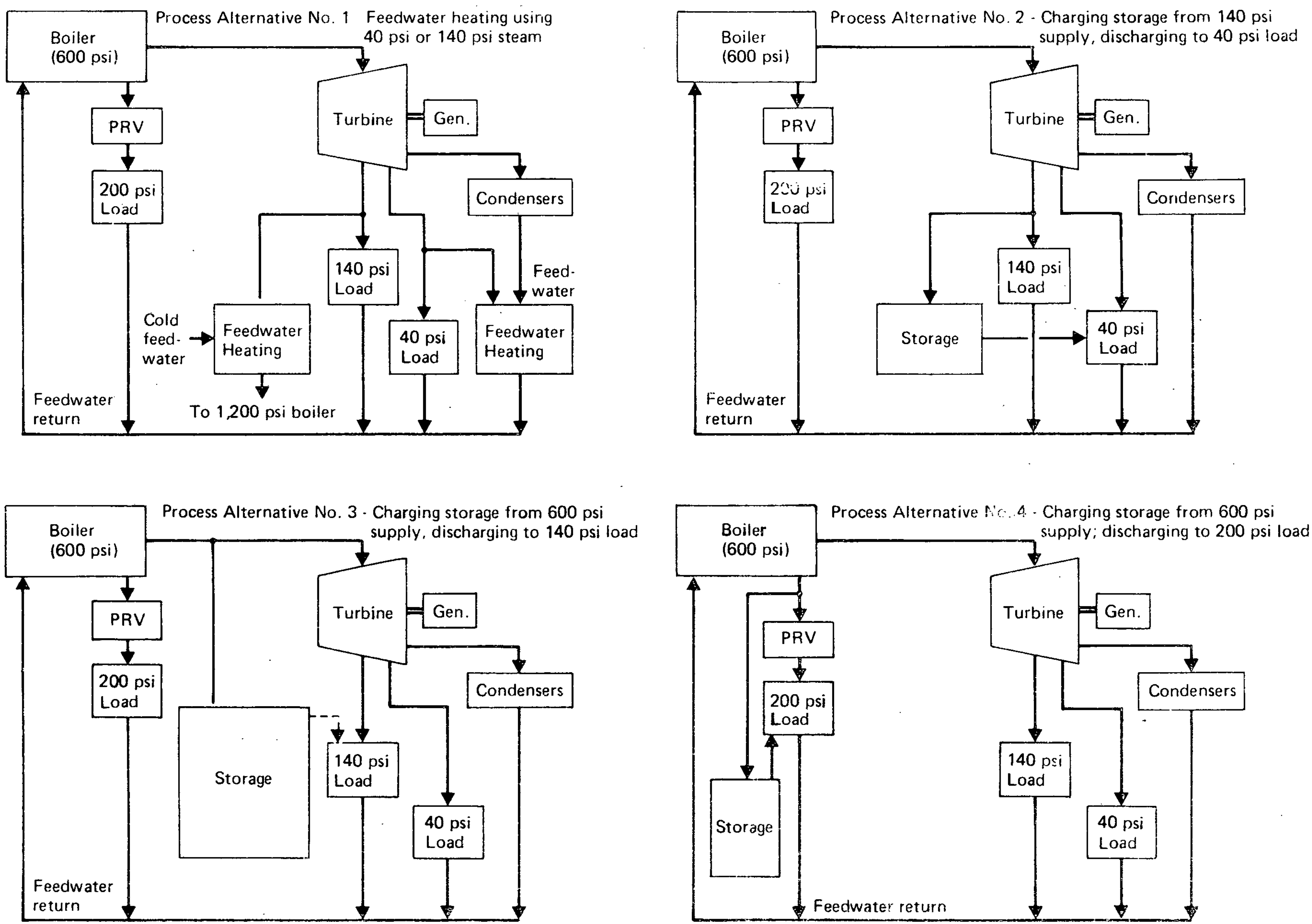


Figure 3-1. Potential Applications of TES to Longview Mill

Further investigation into the magnitude of steam demand fluctuations led to the following conclusions:

1. The 140 psig header steam demand fluctuations are much larger than the fluctuations in the other headers.
2. The 200 psig steam demand is small in comparison with the 140 and 40 psig demands.

The effect of these conclusions is to make charging from the 40 psig header or discharging to the 200 psig header less attractive since there is less opportunity to transfer steam generation from the fossil boiler to the hog fuel boiler. In light of these effects, the process alternatives which were found to be most attractive for storage at Longview were:

- o Charging storage from 140 psig header; discharging to 40 psig header
- o Feedwater heating from 140 psig header

Process alternative No. 3 also retains some appeal. This alternative is thought to provide some operational advantage in that discharge of storage would be directly to the major steam demand - the 140 psig header. However, a potential disadvantage would be the loss in electrical generation caused by the bypassing of the 600-140 psig turbines. This process alternative has not been investigated further.

Storage concepts considered for process alternatives No. 2 are presented in Table 3-1. The technical factors considered were:

- o Technology state-of-the-art
- o State of development

Table 3-1. Storage System Concept Application

Storage Concept	Technical State-of-the-Art	State of Development	Safety, Environment, Maintenance	Thermodynamic Interface	Operation Flexability
1. Sensible heat - solid media JPL - sand and iron ingots	Current technology	Conceptual design being developed	Adequate	590° - 650°F, can be considered for lower temperatures also, should provide thermal stratification	Adequate
2. Sensible heat - rock/oil McDAC	Current technology	SRE tests completed successfully; chosen for solar thermal pilot plant	Oil must be continuously filtered and replaced	Should provide excellent interface; thermal stratification demonstrated in McDAC SRE	Adequate
3. Sensible heat - refractory brick/air BEC	Current technology	Conceptual designs complete; blast furnace preheater experience	Pressure vessel requires careful design; air must be kept free of dust particles	Excellent	Adequate
4. Sensible heat - water variable pressure accumulators	Current technology	Systems in operation	Adequate	Variable pressure regulated by a PRV represents loss in thermodynamic availability	Unknown
5. Latent heat - carbonates Inst. of Gas Tech.	Advanced technology	In SRE stage	Corrosion control required	Melt temp.$>400^{\circ}$F	Adequate
6. Latent heat - metal alloys U. of Delaware	Advanced technology	In SRE stage	Adequate	Melt temp.$>400^{\circ}$F	Adequate
7. Latent heat - hydroxide Comstock & Wescott	Current technology	Component testing for total energy system	Adequate	Melt temp.$>459^{\circ}$F	Adequate
8. Latent heat - Chlorides NRL	Advanced technology	In SRE stage	Corrosion control	Melt temp. = 724°F	Adequate

- o Safety, environmental, maintenance factors
- o Thermodynamic interface with process steam system
- o Operational flexibility

The data contained in References 1 and 2 serve as the primary basis for this evaluation. The results for each concept are also presented in Table 3-1.

Conclusions drawn from this initial screening of potential storage concepts are as follows:

1. All latent heat concepts have melting points out of the range of our process system application (i.e. > $370^{o}F$). Previous BEC TES work indicates a 330^{o} - $340^{o}F$ melt temperature would be desirable. Nitrates as a class of compounds have potential candidate storage medium compounds in this range. An initial conversation with Comstock and Wescott[3] about the applicability of their work with Thermkeep as a latent heat storage medium revealed that a eutectic of NaOH and KOH which is 42% NaOH by weight has a melt temperature at $338^{o}F$. Although no working experience with this NaOH - KOH system as a TES medium is available, Comstock and Wescott would expect it to behave similarly to Thermkeep. A rough estimate of the storage medium cost to store the equivalent of 100,000 lbm/hr of 140 psig steam for 0.5 hour is $200,000. Since containment and heat exchanger costs would have to be added, this particular alternative did not appear to be as economically attractive as some of the other concepts. Contributing to the decision to not pursue this storage concept was the considerable developmental work that would be required to confirm this concept as applicable in the "near term", i.e., early 1980's.

2. The rock/oil sensible heat TES was favored over the refractory brick/air approach because of the demonstrated performance of the McDAC SRE test. Also, a pressure vessel for storage medium containment would not be required. A subsequent re-evaluation of the rock/oil approach revealed that the temperature range of the proposed process application (290^{0} - 360^{0}F) was substantially below the minimum oil temperature (450^{0}F) for the McDonnell-Douglas Solar Thermal Power Plant storage subsystem design. The effect of the lower temperature range resulted in poor heat transfer characteristics due to the viscosity increase of the oil (Caloria HT-43) at the lower temperatures. The oil was replaced in this initial screening effort by ethylene glycol which exhibits better heat transfer in this temperature range.

3. Further investigation was required to evaluate relative merits of a variable pressure accumulator against a rock/intermediate fluid device.

For the feedwater heating as represented in the process alternative, No. 1, constant pressure accumulators were identified as being most applicable. This is especially true for the Longview-Weyco application where a large feedwater tank and oversized de-aerator was installed with the hog fuel boiler in anticipation of the addition of another hog fuel boiler. Straight-forward modification of the de-aerator/feedwater tank subsystem would allow the potential operation as a constant pressure accumulator.

As a result of the initial screening described in the previous paragraphs, initial sizing and cost estimates were performed on the following to allow a second level screening of storage concept types:

1. Constant pressure accumulator operating at 140 psig;
2. Variable pressure accumulator operating between the 140 and 40 psig headers;
3. Packed rock with ethylene glycol as an intermediate working fluid.

Relative cost data are presented in Figure 3-2 for each concept for a range of steaming capacities of 50, 100, 150 $X10^3$ lbm/hr and storage times of 0.25, 0.50 and 1.0 hours. The cost estimates were for mechanical equipment only and were based on the data base given in Table 3-2. Although some of the unit cost data presented in Table 3-2 were preliminary and were revised later in the study, the behavior shown in Figure 3-2 accurately shows the relative economic potential of the storage concepts.

The accumulator technologies show clear economic advantage in the range of storage times less than 0.75 hour. A rock/ethylene glycol system shows a potential economic advantage over the variable pressure accumulator at high steaming rates and longer storage times. Two ΔT's are shown in Figure 3-2. The $\Delta T = 83°F$ would be representative of operation with no feedwater heating while the $\Delta T = 150°F$ would hopefully represent the operation with feedwater heating. The effective ΔT to use was not exactly defined at that time. Calculation of the effective ΔT value would require the operation of a given storage system design in the plant operation program over a period of time to evaluate

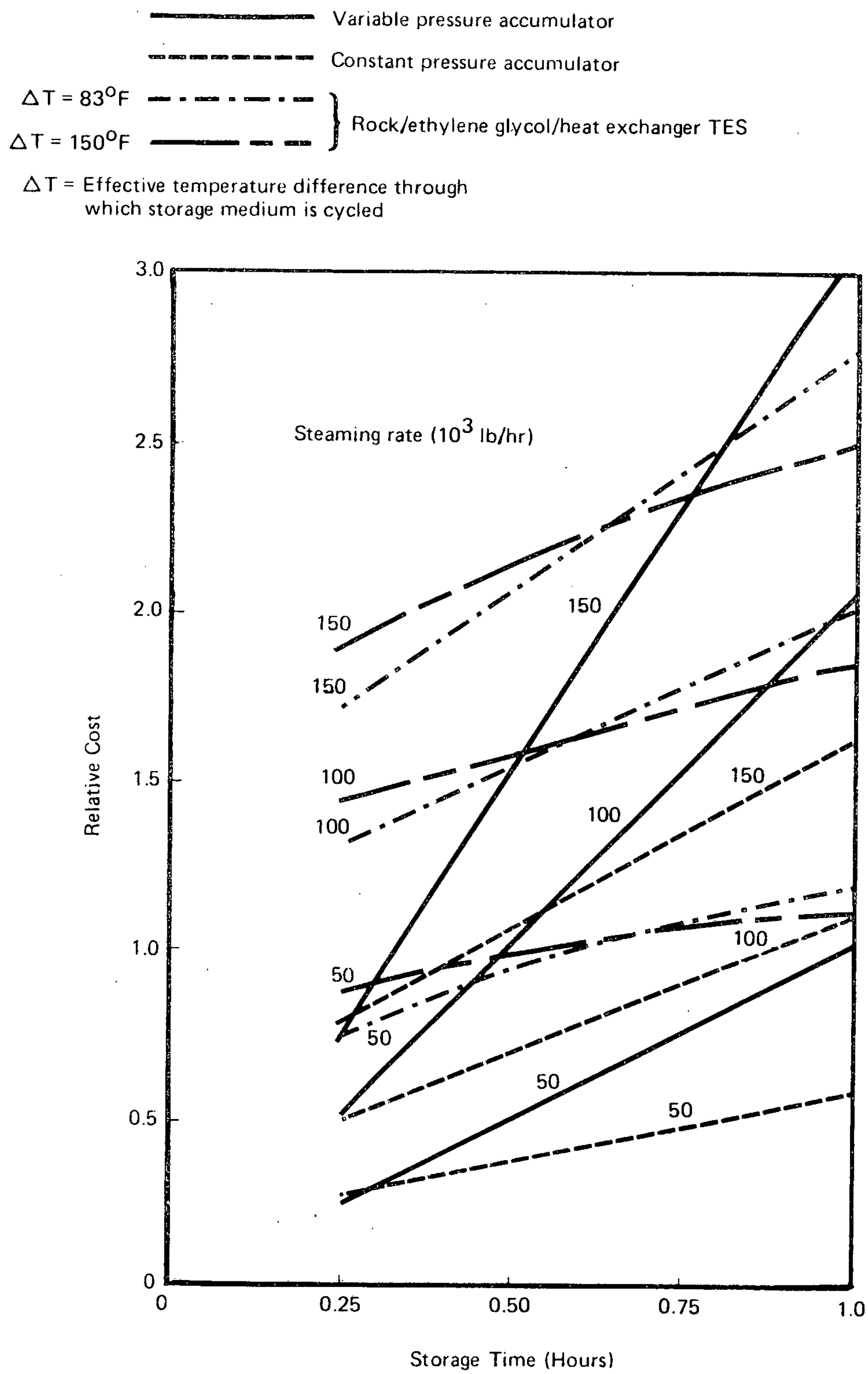


Figure 3-2. Storage Device Cost Estimates

Table 3-2. Data Base for Initial Screening Effort

Property data

h_{fg}	$= 920$ Btu/lb	
ρ_{wf}	$= 60$ lb/ft^3	ethylene glycol at T = 330°F
C_{pwf}	$= 0.7$ Btu/lb · $^\circ$F	ethylene glycol at T = 330°F
ρ_m	$= 165$ lb/ft^3	rock
C_{pm}	$= 0.20$ Btu/lb · $^\circ$F	rock
ε	$= 0.25$, void fraction in rock	
P	$= 140$ psig, design pressure	
S	$= 13.7 \times 10^3 \times 0.8$ psi design stress	SA-516 carbon steel, ASME Code, nonradiographically inspected
E	$= 0.7$, weld efficiency	SA-516 carbon steel, ASME Code, nonradiographically inspected
γ_m	$= 484$ lb/ft^3, metal density	SA-516 carbon steel, ASME Code, nonradiographically inspected
α	$= L/D = 4$, vessel length/diameter ratio	
γ_c	$= 150$ lb/ft^3, concrete density	
k_I	$= 0.042$ Btu/ft-hr-$^\circ$F, insulation conductivity	
t_w	$= 0.125$ inch for liner	

Cost data (preliminary)

C_v	$= 1.00$ \$/lb, welded steel vessel
C_l	$= 0.50$ \$/lb, liner
C_c	$= 0.025$ \$/lb (100 \$/cu. yd) reinforced concrete
C_I	$= 0.25$ \$/ft^3 (.13 \$/ft^2 for 6 inches), insulation
C_{wf}	$= 0.14$ \$/lb (1.0 \$/gal.), ethylene glycol
C_m	$= 0.02$ \$/lb (40 \$/ton), rock
$C_{H/X}$	= heat exchanger costs = 50,000 \$/each for 100,000 lb/hr steam rate, $\sim \dot{m}^{0.67}$ for different steaming rates

the penalty associated with transfering energy into and out of the storage medium. Since operation with the process model was not available at that time, the actual values were not available. However, the values used above should provide minimum costs. Even on a minimum cost basis, the rock/ethylene glycol approach does not appear to be economically justified for a nominal design point of 100,000 lbm/hr capacity, 0.5 hour storage time.

The variable pressure accumulator, in addition to potential economic advantage, offers increased operational flexibility through its large discharge rate capability. Although the variable pressure accumulator would be designed for a nominal discharge rate, e.g., 100,000 lbm/hr, the accumulator could discharge at much larger rates, e.g., 200-250,000 lbm/hr for short periods. For periods of rapid demand fluctuation, this additional operation flexibility is a useful feature. It is doubtful that a heat exchanger design based on the nominal design steam flow rate could provide the same degree of operational flexibility.

Because of the economic and operational flexibility advantages of the accumulator storage types for this process application, further work in refining the rock/ethylene glycol approach was not justified. It was not possible to clearly eliminate one accumulator type in favor of another based on this screening effort. The study proceeded carrying both accumulator types into the design definition stage.

Although steam accumulators are not a "new" technology, their use in the U.S. has been limited. The following section presents a brief description of steam accumulators and their operation.

3.1.1 Steam Accumulators

Accumulators store steam by transferring the latent heat of vaporization to water. There are wide differences in the types of steam storage installations. This great diversity points to the operational flexibility of steam accumulators. The following paragraphs describe two broad classification of steam accumulators with consideration of the specific process steam application under study. References 5, 6, and 9 contain detailed information about accumulators in general and their applications.

Variable Pressure Accumulator.

In a variable pressure accumulator, a nearly constant mass of water is stored in a vessel while its pressure, i.e., temperature, fluctuates. As shown in Figure 3-3, the accumulator is charged from a steam supply system. The charge rate is regulated by a charge valve. The charging steam flows through the water contained in the accumulator, condenses, and transfers heat to the water, raising the water's temperature and pressure. On discharging, the pressure above the water surface is reduced below the saturation pressure corresponding to the current water temperature. The water evaporates from the water surface supplying steam but lowering temperature and pressure in the accumulator. If the steam is to be supplied to a process load at a constant pressure, the discharge valving not only regulates the flow rate of steam but contains a pressure-reducing valve to lower the discharging steam pressure to that of the process load. A significant advantage of this type of accumulator is that the discharge rate can be large, limited only by the "carry over" of water droplets from the turbulent, rapidly evaporating liquid surface.

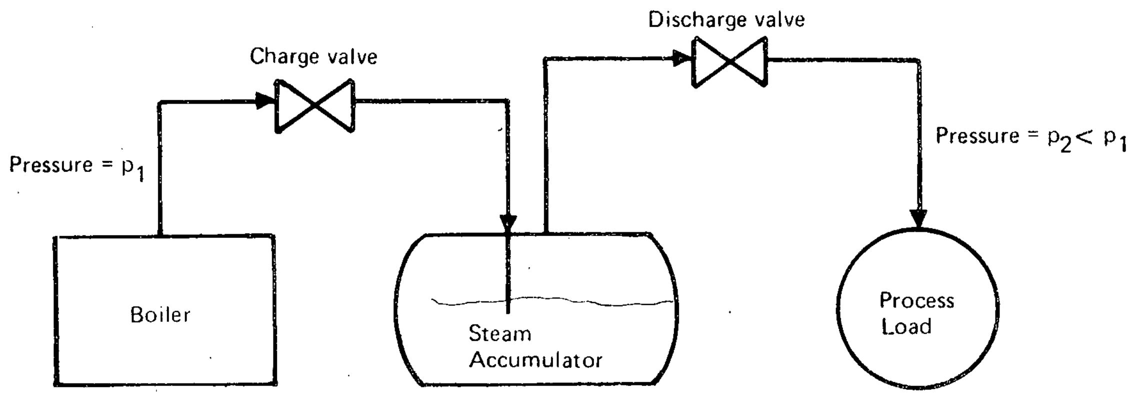


Figure 3-3. Steam Storage with Variable Pressure Accumulator Principle

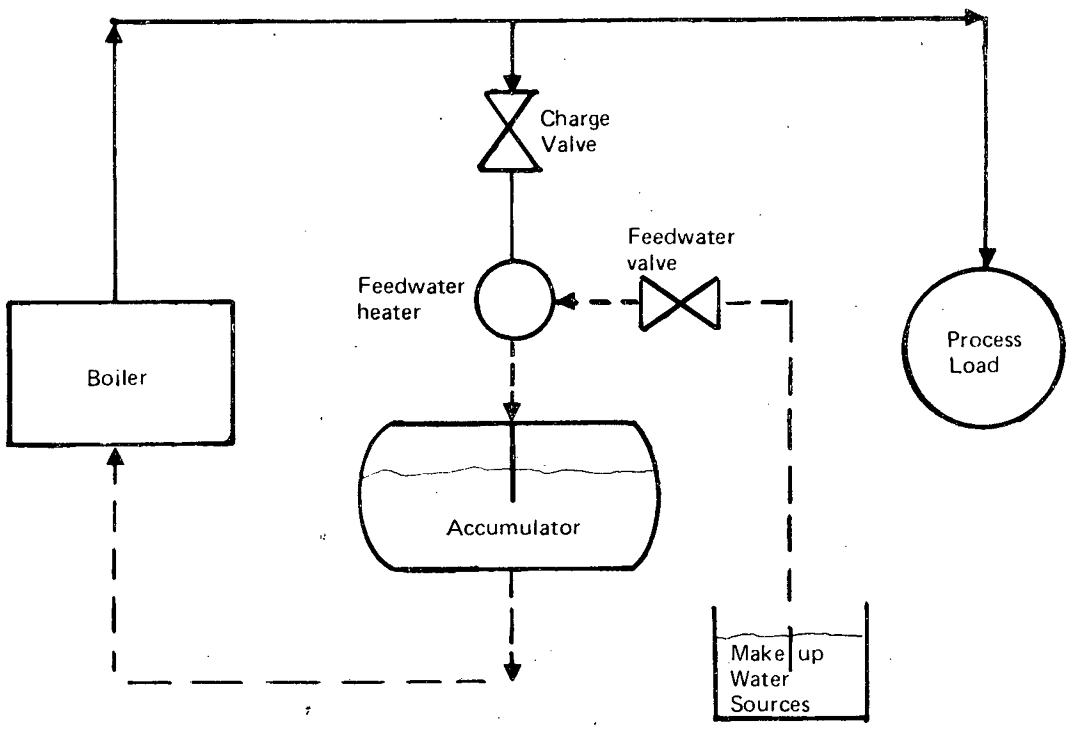


Figure 3-4. Steam Storage with Constant Pressure Accumulator Principle

Constant Pressure Accumulator

In this type of accumulator, the pressure and hence temperature is maintained at a constant value, while the mass of water is varied to store steam. As shown in Figure 3-4, the accumulator is charged by preheating more feedwater than required for boiler feed, with the excess preheated water being stored in the accumulator vessel. During the charging of the accumulator, the boiler would be firing at a higher rate than would be required for the process load alone. During discharging, the steam supplied to the feedwater heater is reduced, however, the boiler continues firing at the desired rate with the additional preheated feedwater being taken out of the accumulator vessel reserve. In the extreme case, all of the boiler steam would be used to meet the process load while the stored water in the accumulator continues to meet the boiler feed requirement.

3.2 TES PERFORMANCE ANALYSIS

The philosophy used in projecting the expected effect of TES on the Longview process steam system was to first operate the plant math model (IPHM) without storage but with the operational flexibility and control strategy expected to be available in the early 1980's, the period in which TES could be first integrated in the Longview mill. This 1980 operation without storage is termed the "Base Case" in the following sections. The details of the assumptions included in the Base Case data have been described in Section 2.1.

The following paragraphs present, first, a comparison of instantaneous performance of the process steam system operating with and without storage. Second, four-day-average performance for the operation with variable pressure and constant pressure accumulators is given.

3.2.1 Instantaneous Performance

This section presents a comparison of the effect of storage on the process steam system. Figures 3-5 and 3-6 show the energy flows for the hog fuel and fossil fuel boilers for the Base Case and operation with a constant pressure accumulator for a small segment of the operating day. Figure 3-5 shows that for the Base Case, the fossil fuel boiler continually fires above its minimum rate in order to meet the process steam demand. Figure 3-6 shows that the CPA allows the fossil fuel boiler to remain at its minimum rate during this period. The hog fuel boiler is allowed to fire at a higher level, the excess going to charge storage. This reduction in fossil fuel firing is equivalent to a savings of 14.4 barrels of oil over this small period. The "net" savings obviously must include the credit for electrical power generation and the debit for additional hog fuel usage. However, this comparison demonstrates the ability of TES to transfer steaming from fossil to wood waste fuels.

3.2.2 Base Case Performance

The Base Case performance as represented by the average of four days operation of IPHM is presented in Figure 3-7. Presented are the fossil fuel boiler steaming rate, hog fuel boiler steaming rate, electrical generation rate and

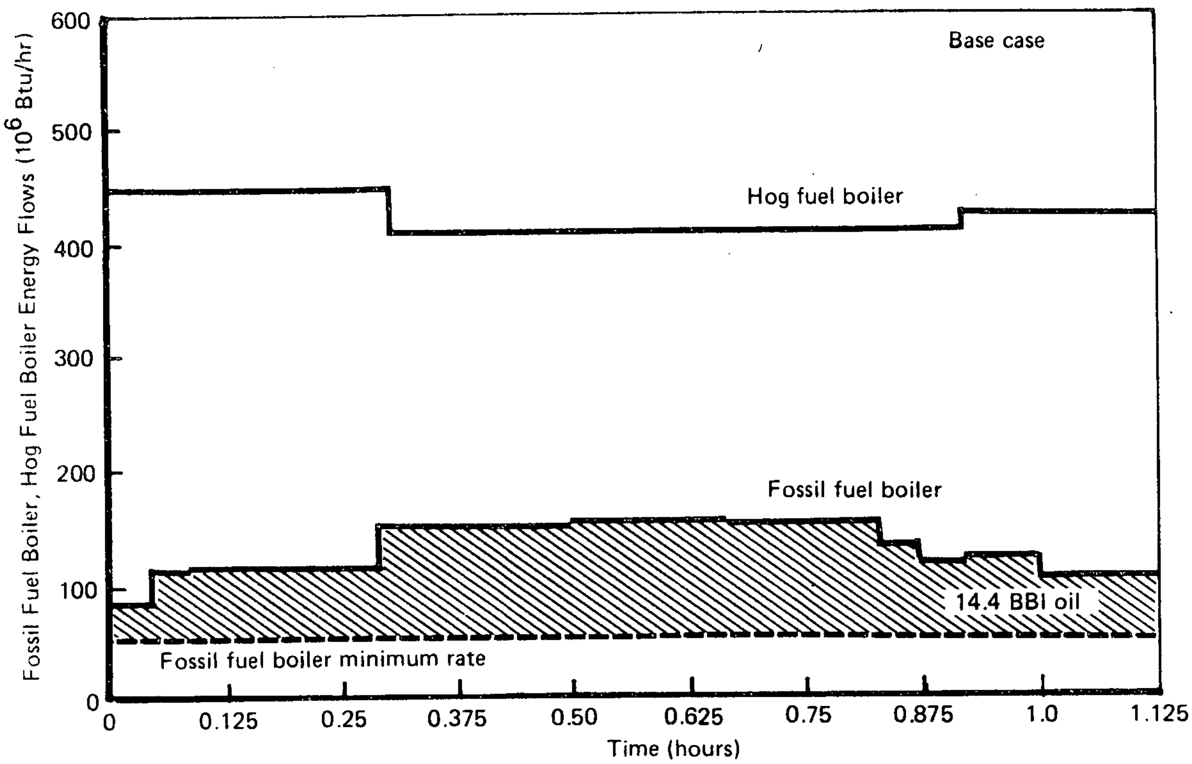


Figure 3-5. Base Case Performance Data

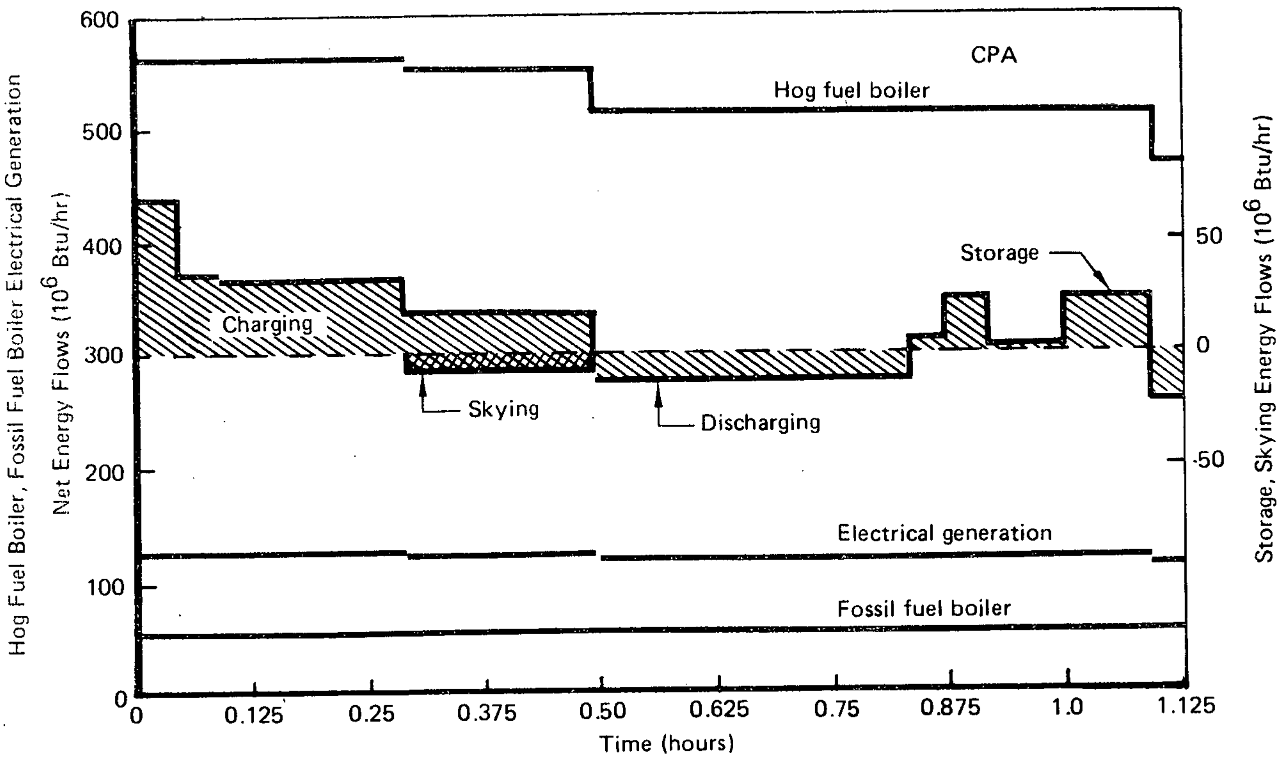


Figure 3-6. Constant Pressure Accumulator Performance Data

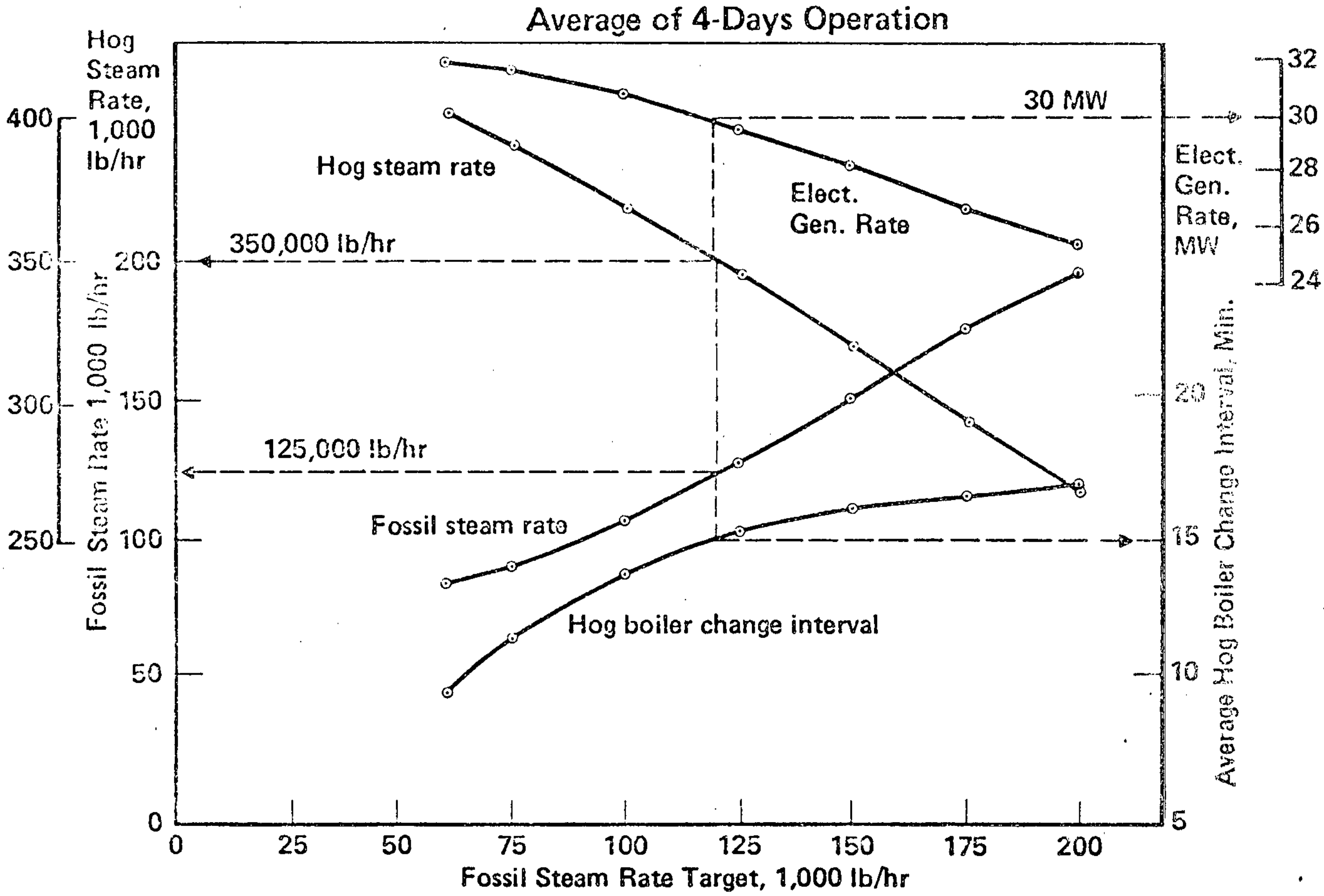


Figure 3-7. Longview Power Plant "Base" Model Performance

average hog fuel boiler change interval as a function of the fossil fuel boiler steaming target. As can be seen, an average HFB change interval of 15 minutes implies a FFB steaming rate of 125,000 lbm/hr, an HFB steaming rate of 350,000 lbm/hr, and electrical generation of 30 MW. The performance of the plant operating with storage will be compared back to this point in order to assess the economic feasibility of TES (See Section 5.1).

Several sensitivity analyses were performed for the plant model operating with storage. As described in 3.1, two accumulator types were studied - variable pressure accumulator (VPA) and constant pressure accumulator (CPA) - Figure 3-8 presents the trade study matrix showing the various areas considered. Charge rate and storage capacity were studied for both VPA and CPA. The VPA analysis was performed first using a control methodology which was later revised when the CPA analyses were performed. The revised control methodology gave significant improvements so that the VPA analyses were repeated with the revised methodology.

3.2.3 VPA Performance

As was discussed earlier, the VPA performance was first analyzed with a less refined control methodology. This less refined methodology affected only the HFB firing rate control logic and differs from that presented in Section 2.2.10, only in that the change of the HFB rate, Δchng, was based solely on amount the inventory was away from the target value, i.e., $\Delta_{TAR} = I_1 - I_{TAR}$. The skying, fossil fuel boiler firing and "empty" accumulator considerations given in steps 6, 10, 11 and 12 of Section 2.2.10 were still considered. This less refined methodology is termed "control on basis of storage inventory" in the following

	Accumulator Type	
Trade	VPA	CPA
Control methodology	✓	
Charge rate	✓	✓
Storage capacity	✓	✓

Figure 3-8. Trade Study Matrix

discussions. The methodology represented by Section 2.2.10 is termed "control on basis of storage inventory plus sense-of-change." The effect of these two control methologies is shown in Figures 3-9 and 3-10. The improved control shows for the desired 15 minute HFB change interval, a substantial reduction in accumulator capacity is possible. The control methodology revision results in negligible fossil fuel boiler steam rate changes but increased electrical generation resulting from the increased HFB firing.

These comparisons of control methodology point to the substantial effect of control philosophy on the storage system performance. There remains a potential for additional benefits from the improved utilization of the storage device via the use of a "smart" control methodology. The magnitude of those potential benefits of improved control remain to be explored.

The variable pressure accumulator as modeled in IPHM has the capability to be charged and discharged simultaneously. An alternative arrangement, expected to be nearly equivalent in performance, is given in Section 3.3.2. The effect of limiting the charge rate was studied by limiting the maximum differential charging rate, i.e., charge rate minus discharge rate, to a range of values. The effect of this maximum differential charging rate and accumulator capacity (i.e., the design mass of <u>steam</u> to be stored) on the average HFB change interval is given in Figure 3-11. As can be seen, the larger the allowable maximum differential charging rate, the smaller the required accumulator capacity for a given desired HFB charge interval. The smaller accumulator capacity translates into a smaller pressure vessel and hence into a smaller capital cost.

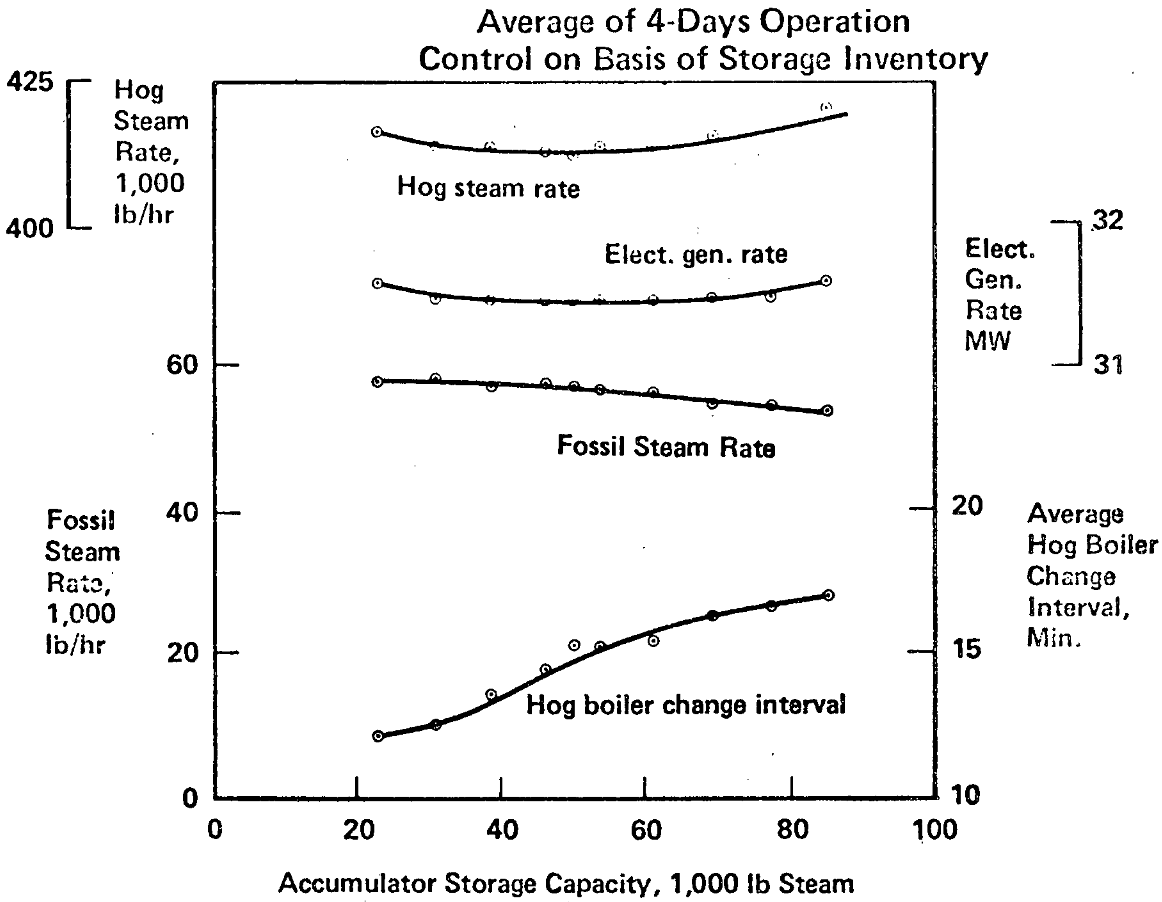


Figure 3-9. Longview Power Plant "VPA" Model Performance

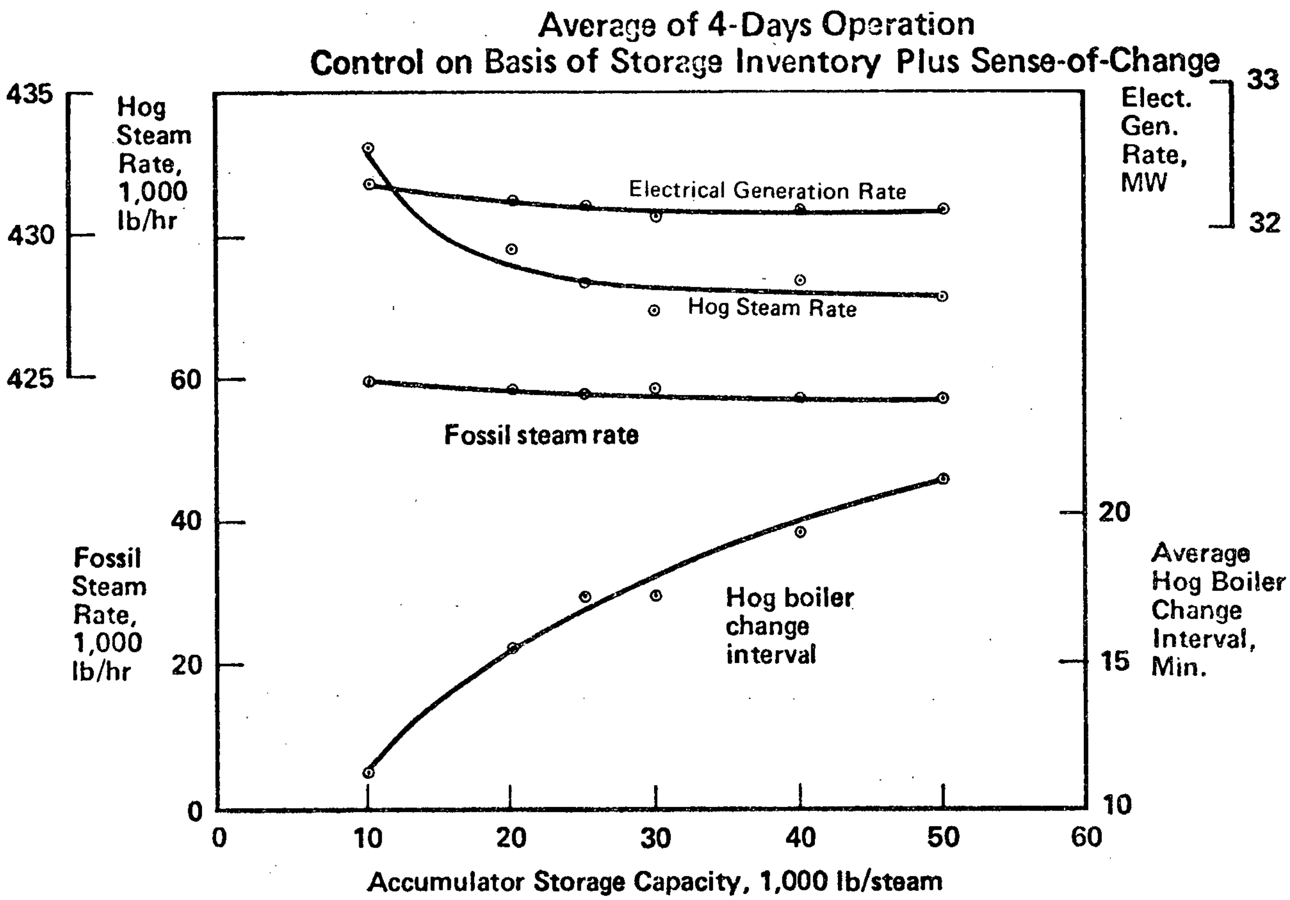


Figure 3-10. Longview Power Plant "VPA" Model Performance

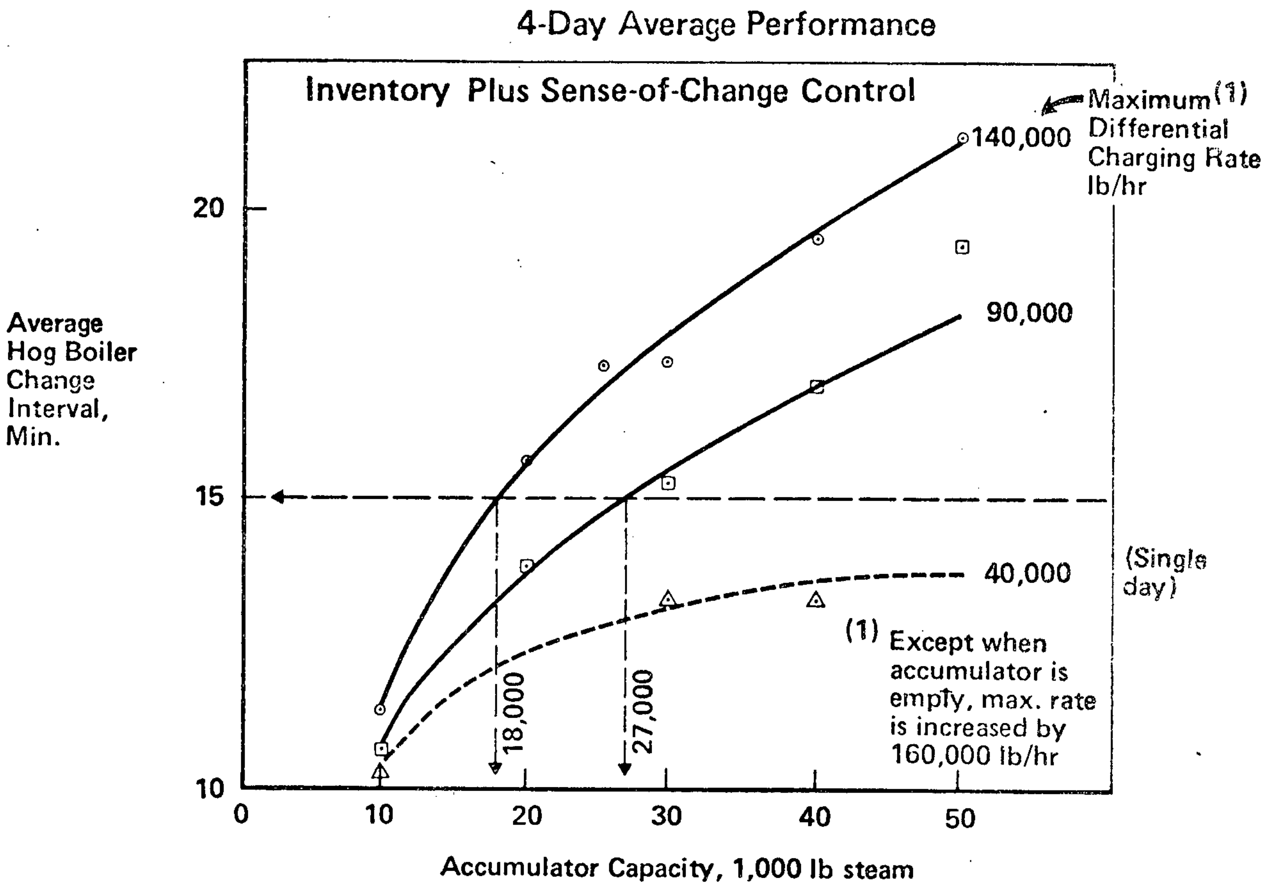


Figure 3-11. "VPA" Maximum Charge Rate/Storage Size Trades

As the differential charging rate decreases, the lesser the design restraints for steam nozzles. However, as the differential charging rate is lowered, the amount and number of skying events increase. Since the HFB rate is changed instantaneously when a skying even occurs, lowering the differential charging rate by too much results in the HFB average change interval always being less than 15 minutes no matter how large the accumulator capacity. As a compromise between the design restraints for the steam nozzles and skying, the value of 100,000 maximum differential charging rate was chosen for the VPA conceptual design. This choice translates into an accumulator capacity of about 25,000 lbm steam for a 15 minute HFB change interval. This accumulator capacity implies a storage time of 0.25 hours.

The VPA performance data for 90,000 lbm/hr maximum differential charging rate is presented in Figure 3-12. Comparison of this data with that given in Figure 3-10 (where maximum differential charge rate = 140,000 lbm/hr) shows a slight decrease in HFB change interval and firing rate and electrical generation.

Comparison between the VPA and Base Case data is given in Figure 3-13. An accumulator capacity of 27,000 lbm steam consistent with the 15 minute HFB change interval yields a savings in fossil fuel generated steam of 71,000 lbm/hr from the base case. Similar comparisons exist for the hog fuel boiler firing and electrical generation. These changes from the base case are presented on an economic basis in Section 5.1.

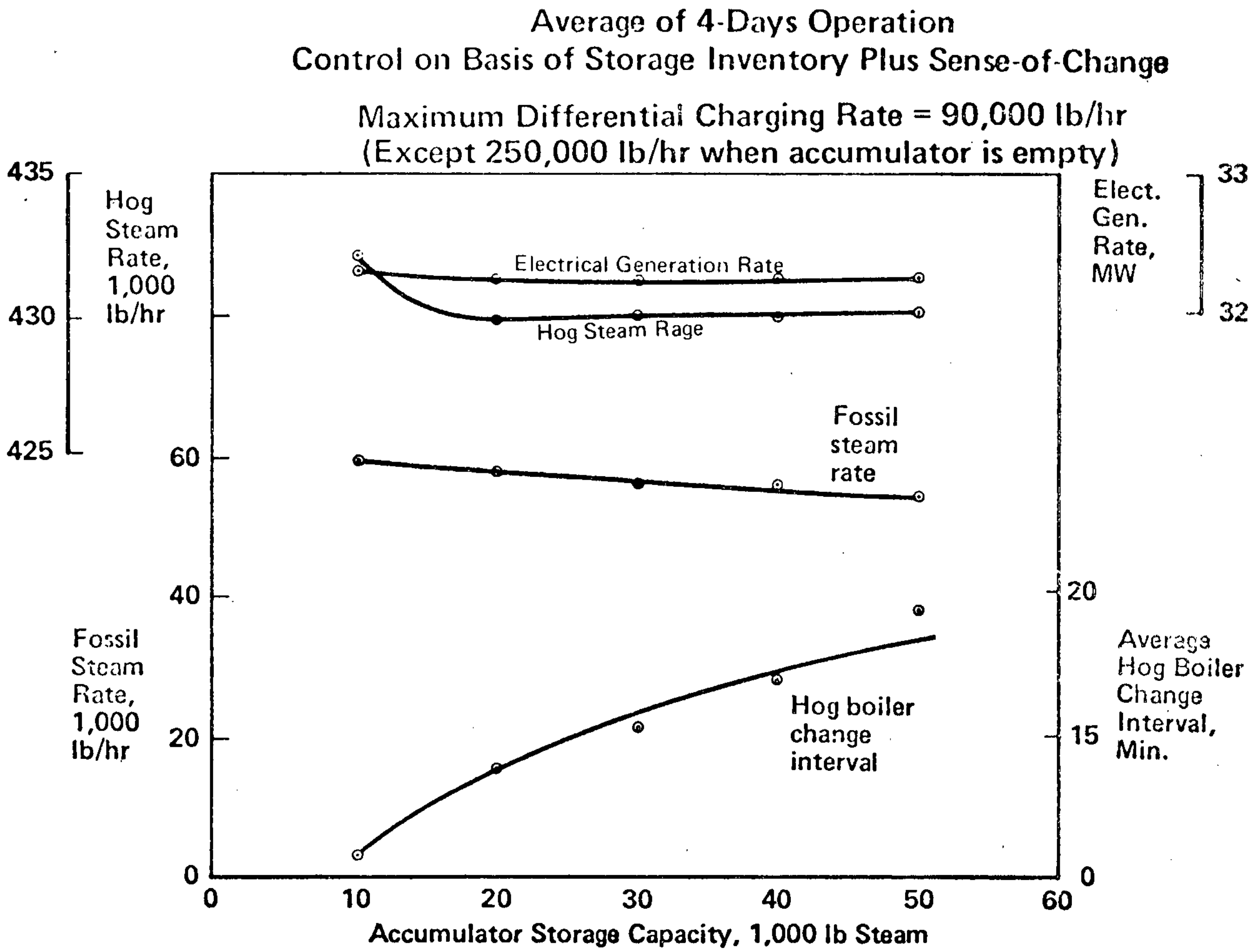


Figure 3-12. "VPA" Model Performance

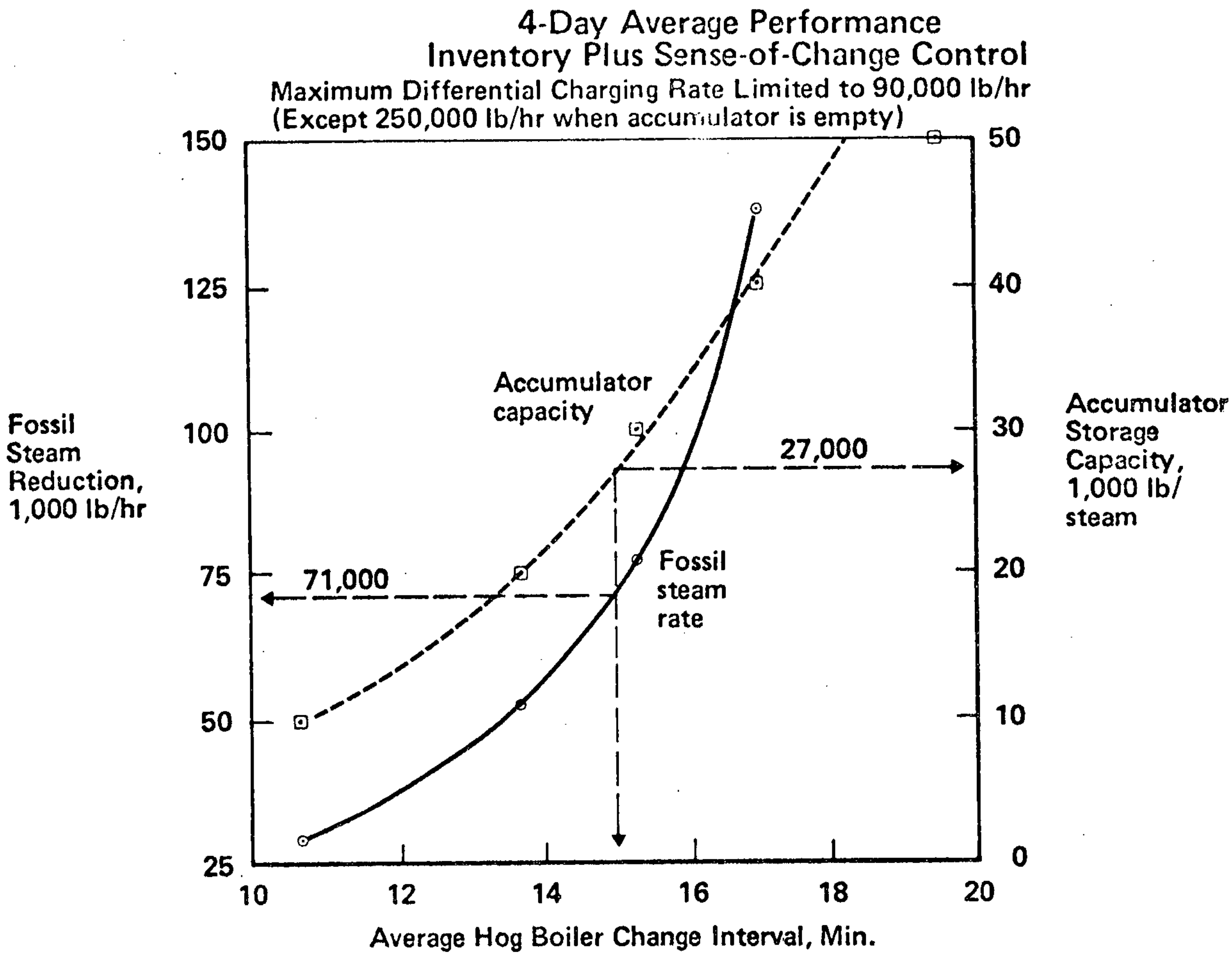


Figure 3-13. Fossil Steam Savings Potential with "VPA"

3.2.4 CPA Performance

The effects of maximum charging rate and accumulator capacity on the HFB change interval for the constant pressure accumulator are shown in Figure 3-14. For the CPA the maximum charge rate is limited to that of the design steaming rate for the de-aerating heater. The accumulator capacity is then the product of this design steaming rate and the storage time.

As shown in Figure 3-14, decreases in maximum charging rate results in increased accumulator capacity to meet the desired 15 minute HFB change interval. The de-aerator is a significant cost component of the TES system. Therefore, the smallest de-aerator that does not dramatically increase the required accumulator capacity is most desirable. Figure 3-14 shows that a further decrease from 75,000 lbm/hr to 50,000 lbm/hr results in the 15 minute HFB change interval not being satisfied no matter how large the storage capacity is made. The CPA conceptual design has been based on 75,000 lbm/hr charging rate and 0.275 storage time, i.e., a 20,625 lbm steam accumulator capacity.

The effect of CPA accumulator capacity on other CPA performance variables is shown for the 75,000 lbm/hr maximum charging rate in Figure 3-15. The potential fossil steam savings over the Base Case is shown in Figure 3-16. As is shown, an accumulator capacity of 21,000 lbm steam translates into a fossil steam savings of 64,000 lbm/hr. As with the VPA, the effect of these performance changes on an economic basis is given in Section 5.1.

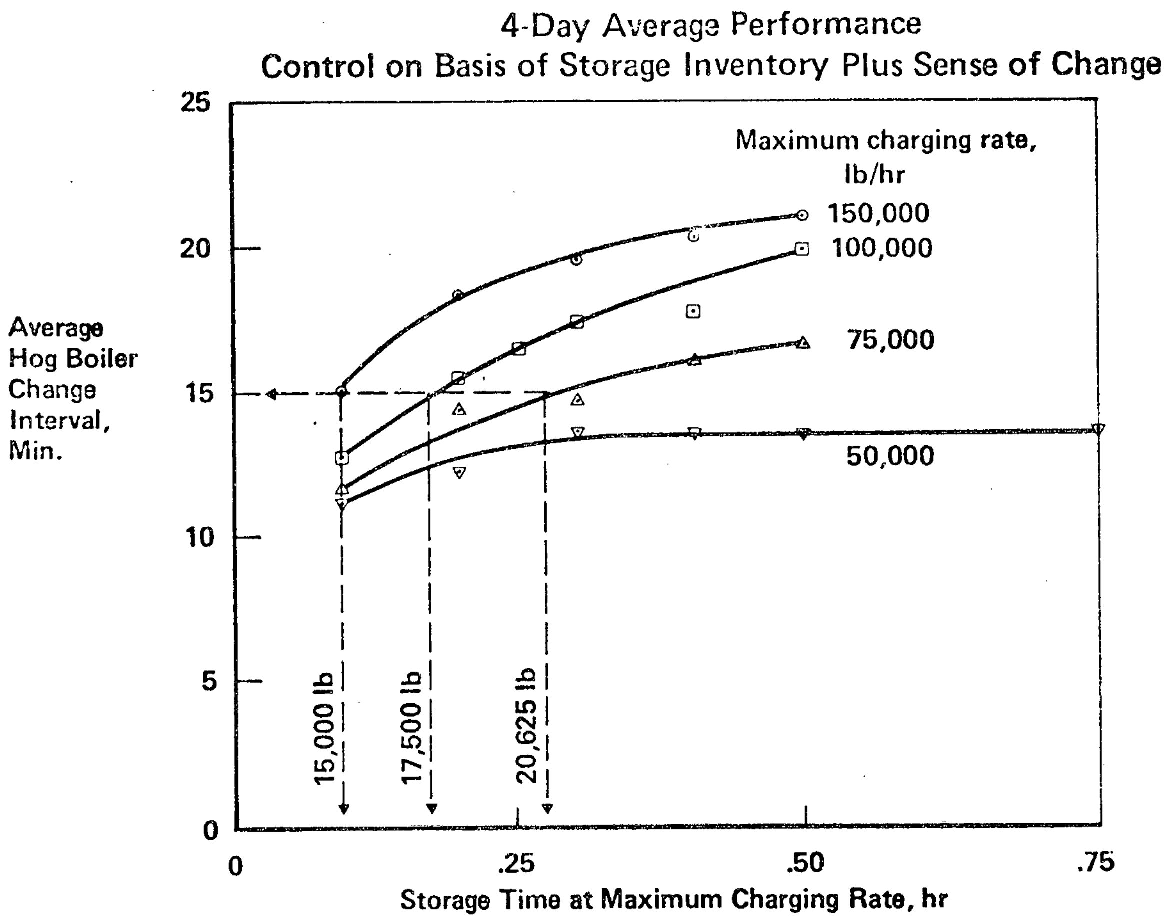


Figure 3-14. "CPA" D.A. Heater Size/Storage Size Trades

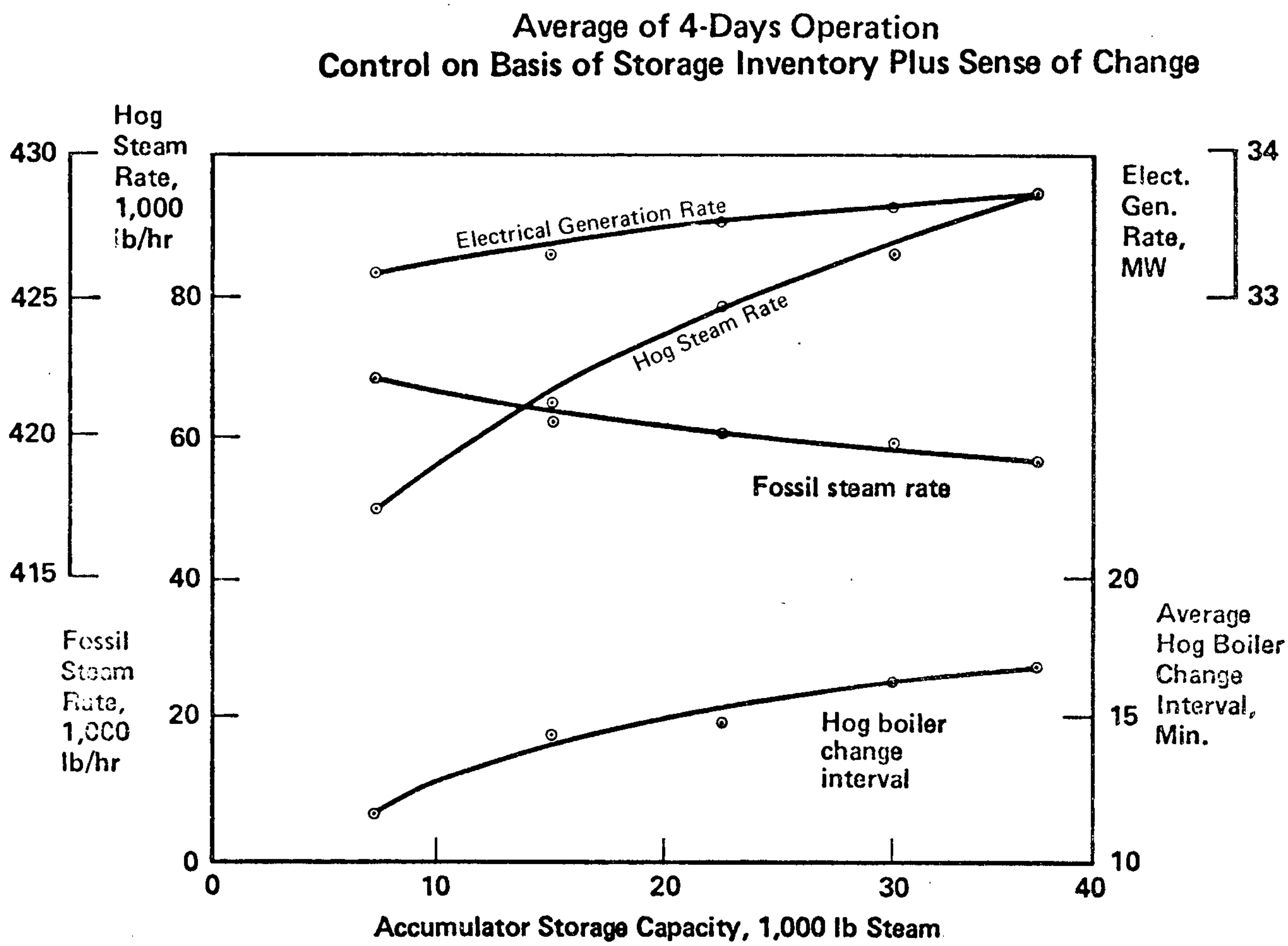


Figure 3-15. 75,000 lb/hr "CPA" Model Performance

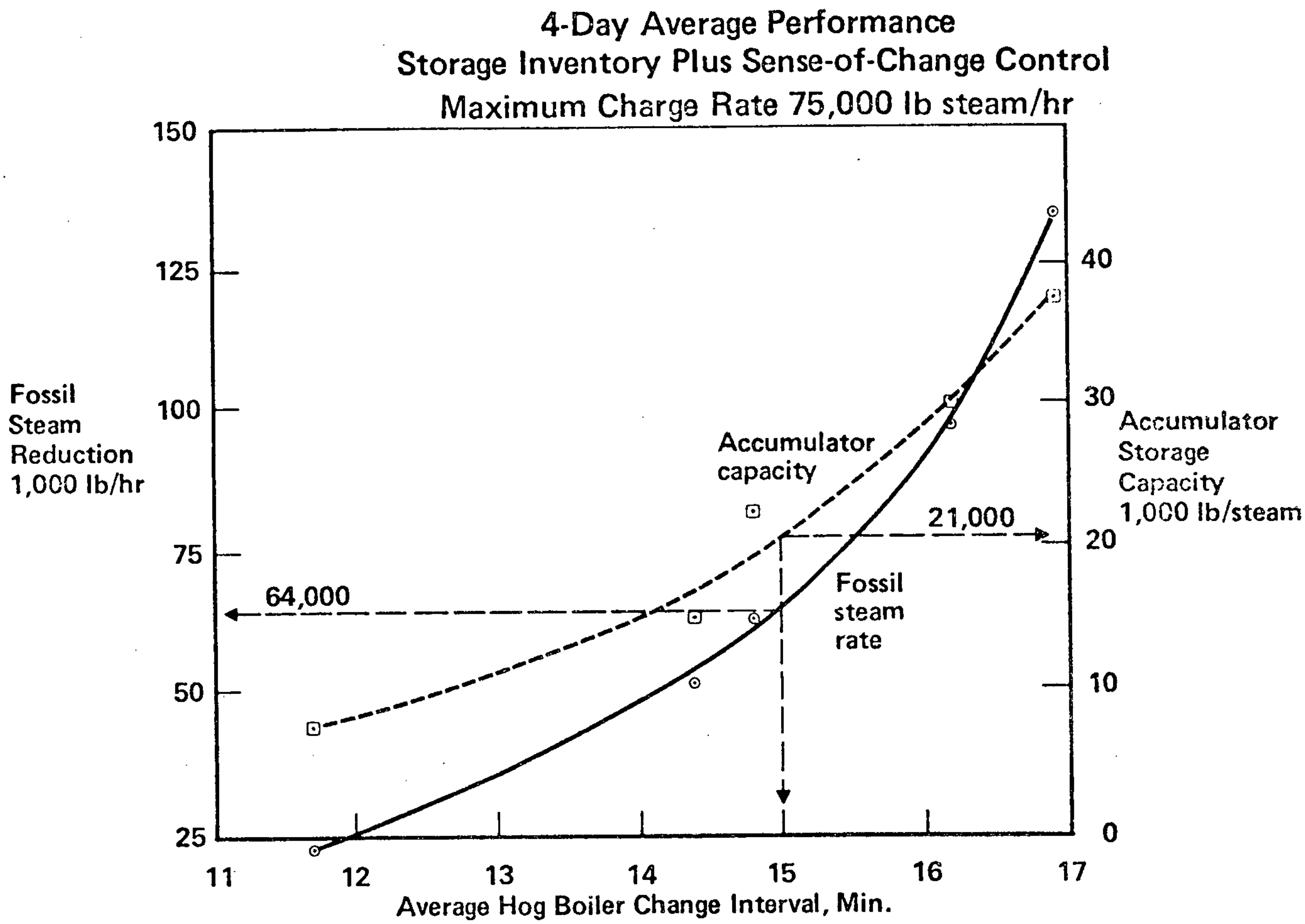


Figure 3-16. Fossil Steam Savings Potential with "CPA"

3.3 STORAGE DEVICE CONCEPTUAL DESIGN

3.3.1 Sizing Analysis

Variable Pressure Accumulator.

The volume, V, of water required to store steam at a nominal steaming rate of $\dot{m}_s$, lbm/hr, and for a storage time (full to empty) of τ, hours, is given by

$$V = \frac{\dot{m}_s \tau}{g_s} \tag{3-1}$$

Where g_s = weight of steam released per ft^3 of water contained in the accumulator for a pressure drop from p_1, to p_2, psia

The parameter, g_s can be approximated by [4]

$$g_s = \frac{1}{2}\left\{10 \log_{10}\left(\frac{p_1}{p_2}\right) + p_1^{1/2} - p_2^{1/2}\right\}, \quad \left[\frac{\text{lbm steam}}{\text{ft}^3 \text{ water}}\right] \tag{3-2}$$

For example, for $\dot{m}_s$ = 100,000, τ = 0.25 hour, p_1 = 140 psig = 155 psia, p_2 = 50 psig = 65 psia, then:

$$g_s = 4.08 \ \frac{\text{lbm steam}}{\text{ft}^3 \text{ water}}$$

The effect of pressure on the storage density, g_s, is shown in Figure 3-17. Defining the following:

$$\Delta p = p_1 - p_2$$
$$\alpha = \frac{\Delta p}{p_1} \tag{3-3}$$

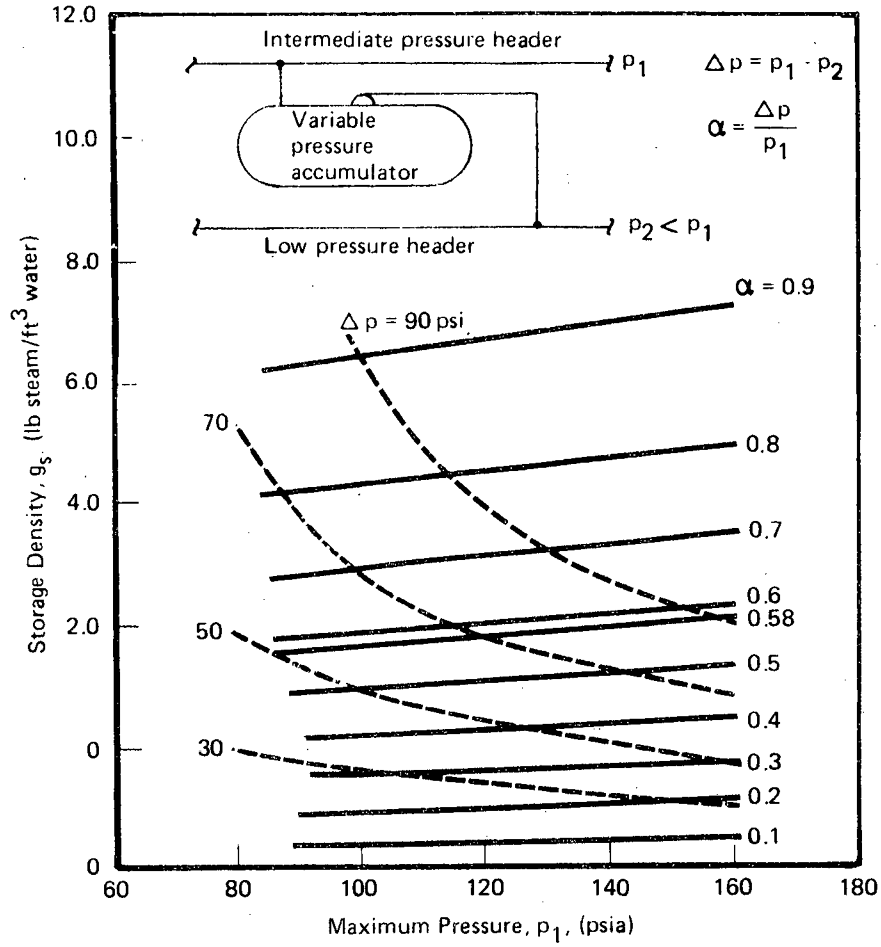


Figure 3-17. Effect of Pressure Difference on Storage Density

then g_s is given by

$$g_s = \frac{1}{2}\left\{10 \log_{10}\left(\frac{1}{1-\alpha}\right) + p_1^{1/2}\left[1-(1-\alpha)^{1/2}\right]\right\} \quad (3\text{-}4)$$

As can be seen, the storage density is strongly affected by the pressure and pressure drop. As an example, a pressure drop from 155 psia to 103.5 psia (Δp = 155 - 103.5 = 51.5 psi) yields a g_s = 2.06 lbm/ft^3, whereas a drop from 103.5 psia to 65 psia (Δp = 103.5 - 65 = 38.5 psi) also yields g_s = 2.06 lbm/ft^3. The 103.5 psia point represents the position where each cubic foot of water has equal ability to absorb or release steam relative to the 140 or 40 psig headers. This pressure corresponds to the inventory target value, ITAR, for the VPA, i.e., ITAR = 0.556 (see Section 2.2.10).

The required volume is given by substitution into Equation (3-1).

$$V = \frac{100{,}000 \times 0.25}{4.08} = 6126 \text{ ft}^3 \text{ of water}$$

An additional ten percent in volume is provided to allow for sufficient evaporating surface area inside the accumulator. Therefore, the total required volume would be:

$$V_t = 6126 \times 1.10 = 6738 \text{ ft}^3$$

For a cylindrical tank with 2:1 ellipsoidal heads, the volume is given by

$$V_t = \frac{\pi}{4} D^2 L + \frac{\pi}{12} D^3 \tag{3-5}$$

where D = tank inside diameter

L = length of cylindrical portion of tank

If L = nD then

$$V_t = \left(\frac{n}{4} + \frac{1}{12}\right) \pi D^3 \tag{3-6}$$

For D = 12 ft, V_t = 6738 ft^3 when n = 4.63 or L $\approx$ 56 ft

If sufficient surface area between the liquid and vapor phases inside the accumulator is not maintained, the evaporating steam can begin to "carry over" water into the discharge line. Lyle[5] gives the following empirical relation for the maximum discharge rate

$$\frac{\dot{m}_{sd}\big|_{MAX}}{A_s} = 3 \cdot p \tag{3-7}$$

where p is expressed in psia. Therefore, when full p = 140 psig = 155 psia or

$$\dot{m}_{sd}\big|_{MAX} = 3 \cdot 155 \cdot A_s$$
$$= 465\, A_s$$

When the tank is "full", the water volume is 90% of the total tank volume. Lyle gives that for a horizontal cylindrical vessel 90% full the surface area is 71.1% of the cross sectional area. For D = 12 ft, L - 56 ft then

$$A_s = 0.711\ DL = 478\ ft^2$$

Therefore, when "full" the maximum discharge rate is

$$\dot{m}_{sd}\Big|_{MAX} = 465 \times 478$$
$$= 220,000\ lbm/hr$$

This is larger than the 160,000 lbm/hr nominal required discharge rate indicated by the industrial process heat model.

In the charging mode of operation, Goldstein[(6)] indicates a "safe" steam velocity of 50 m/s (164 fps) from the nozzles. For ¼ inch diameter nozzle holes, m holes per nozzle and n nozzles, the steam flow area is

$$A_{fs} = mn \frac{\pi}{4}\left(\frac{0.25}{12}\right)^2$$
$$= 3.41 \times 10^{-4}\ mn,\ [ft^2]$$

The steam velocity in fps is given by

$$v = \frac{\dot{m}_s}{\rho_s A_{fs}} \cdot \frac{1}{3600}$$

For $m_s = 300{,}000$, $\rho_s = 0.344 \frac{lbm}{ft^3}$ (i.e., 140 psig),

$$v = \frac{300{,}000}{0.344 \times 3.41 \times 10^{4} \; mn \times 3600}$$

or $nm = 4332$ for $v = 164$ fps

This would be satisfied with m = 72 holes/nozzle and n = 60 nozzles.

Constant Pressure Accumulator

The volume of water required for given $\dot{m}_s$ and τ are given as before by

$$V = \frac{\dot{m}_s \tau}{g_s} \qquad (3\text{-}1)$$

However, g_s is given by

$$g_s = \rho_w \frac{(h_b - h_{fw})}{(h_s - h_{fw})} \qquad (3\text{-}8)$$

where ρ_w = density of stored water = 55.16 lbm/ft^3 at 140 psig

h_b = density of boiler feedwater = 334 BTU/lbm

h_{fw} = cold feedwater enthalpy = 44 BTU/lbm

h_s = charging steam enthalpy = 1210 BTU/lbm

With these values, $g_s = 13.718$ lbm steam/ft^3 water.

For $m_s = 75{,}000$, $\tau = 0.275$, $V = 1503$ ft^3. Adding 10% for reserve, V_t = $1503 \times 1.1 = 1654$ ft^3.

3.3.2 Design Description and Cost Estimates

Variable Pressure Accumulator

The variable pressure accumulator conceptual design consists of an insulated pressure vessel, control system, internal piping, valving and connections to existing steam headers as shown schematically in Figure 3-18. When "full" the accumulator pressure is at the 140 psig of the header. As the accumulator discharges, the accumulator pressure drops. In order to maintain the steam entering the 40 psig header at 40 psig, a pressure reducing valve (PRV) is used on the downstream side of the accumulator control valve. Since a minimum of 10 psig pressure differential must be maintained across the PRV for effective operation, the accumulator is considered "empty" when the accumulator pressure reaches 50 psig.

The installation schematic shown in Figure 3-18 will allow the accumulator to be charged and discharged simultaneously. Because the largest steam demand fluctuations occur on the 140 psig header, the variable pressure accumulator as connected in Figure 3-18 can be envisioned as a PRV with capacity. The discharge continues at a more or less constant rate while the charging rate fluctuates rapidly corresponding to the rapid changes in the 140 psig header. An alternative installation schematic is shown in Figure 3-19. In this schematic the accumulator piping is so constructed that the accumulator is either, but not both, charged or discharged. This arrangement would lessen the magnitude of the charge rate allowing the use of fewer nozzles. The surface area requirement for discharge without "carryover" (see Section 3.3.1) would also be less of a concern since the magnitude of the discharge rates would be smaller.

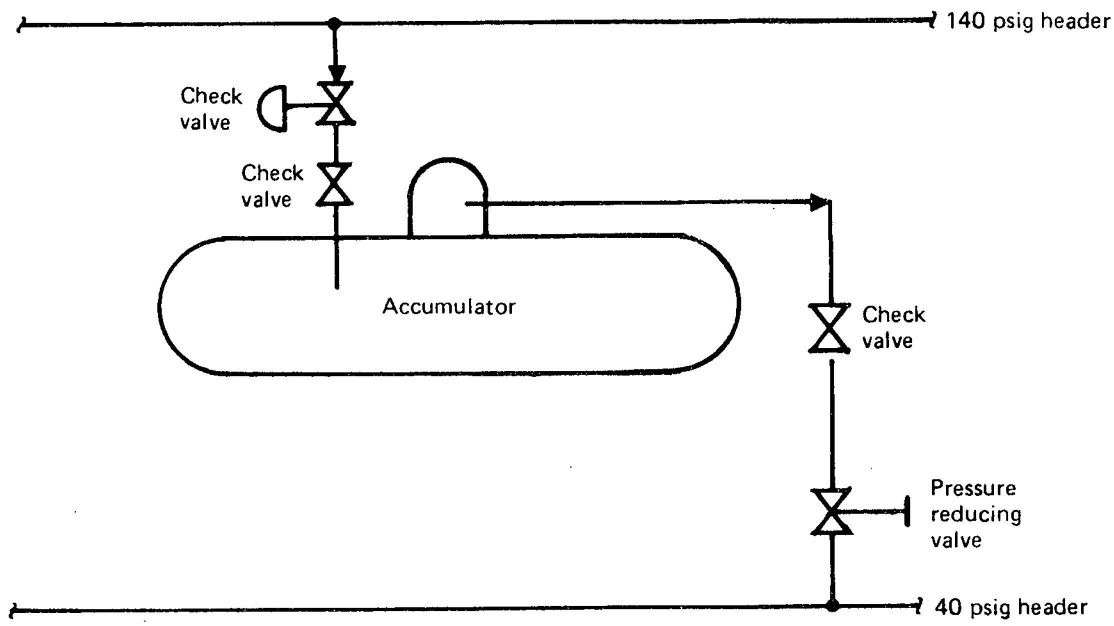


Figure 3-18. Variable Pressure Accumulator Installation Schematic

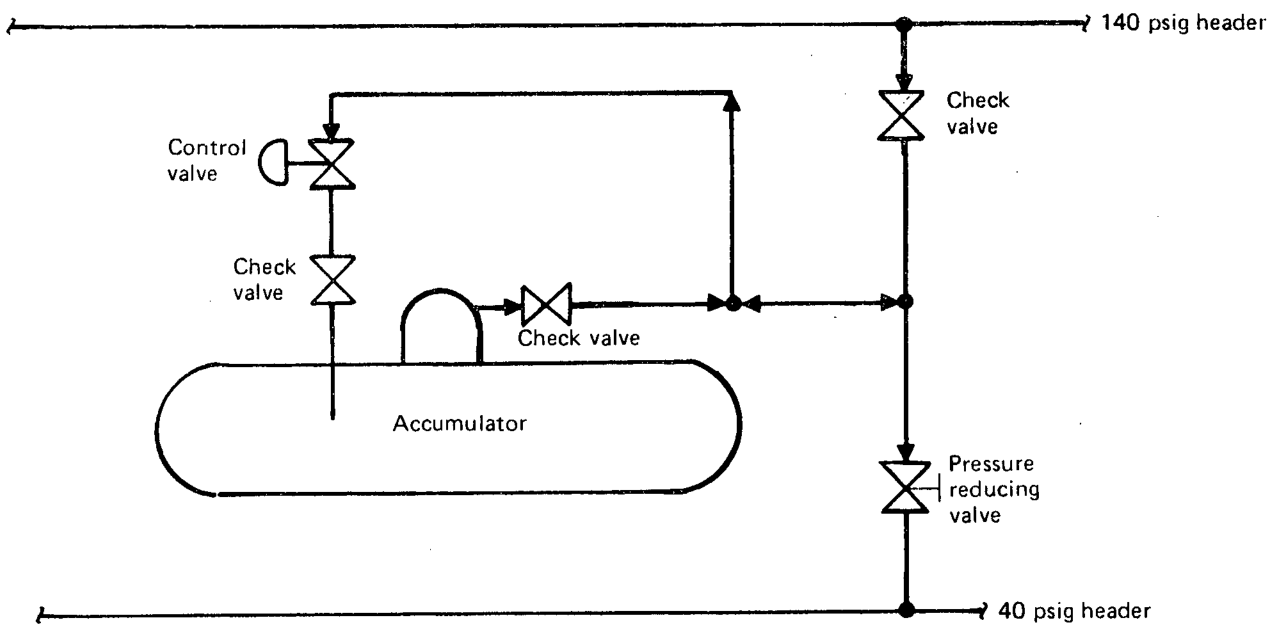
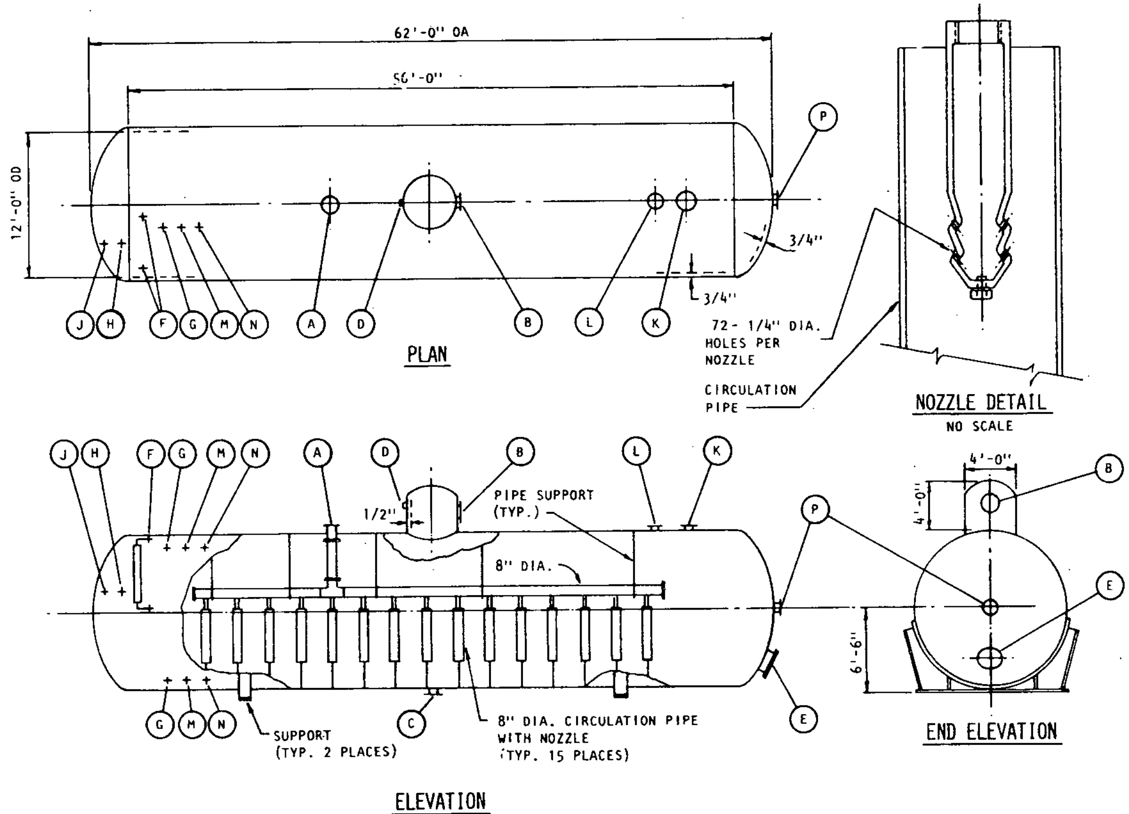


Figure 3-19. Alternate Variable Pressure Accumulator Installation Schematic

The mechanical system design of the variable pressure accumulator is shown in Figure 3-20 and described in Table 3-3. The horizontally placed, insulated cylindrical pressure vessel has 2:1 ellipsoidal heads and is designed to ASME Boiler and Pressure Vessel Code, Section VIII, Division I. The internal piping design involves standard piping with the nozzles and circulation pipe configured as shown in the detail of Figure 3-20. Exiting steam is projected upward from the nozzle holes, the steam flow pulling additional water into the bottom of the circulation pipe. This action keeps the water well mixed and avoids temperature gradients between the steam and water spaces.

The control system conceptual design is represented in Figure 3-21. A minicomputer receives process measurements from the existing analog control system. These include header pressures, boiler flows, condenser flows, accumulator flows and state-of-charge, and electrical generation rates. The minicomputer analyzes the process measurements and their trends over the immediate past (e.g., 15 minutes) and makes decisions based on the control algorithm programmed as to the desired values of the set points for the hog fuel boiler flow, accumulator flow and condenser flow. The set point data is passed back to the existing analog control system. A CRT Terminal allows the monitoring of the status of the system and the modifying of system parameters. A printer supplies hard copies of system data for future reference. A data storage system provides the programming for the minicomputer as well as a means to store pertinent data about the system that will allow both a projection of the steam requirements in the next few minutes of operation and a methodology of meeting the projected requirements.



NOZZLE SCHEDULE			
MARK	QTY	SIZE	SCHEDULE
A	1	8"	STEAM INLET
B	1	12"	STEAM OUTLET
C	1	6"	ACCUMULATOR DRAIN
D	1	2"	RELIEF VALVE CONNECTION
E	1	16"	INSPECTION MANHOLE
F	2	1½"	GAUGE GLASS CONNECTION
G	2	1½"	LEVEL ALARM CONNECTION
H	1	1	THERMO CONNECTION
J	1	3/4"	PRESSURE CONNECTION
K	1	6"	VACUUM BREAKER
L	1	4"	MAKE-UP WATER CONNECTION
M	2	2"	BLOW DOWN CONTROL CONNECTION
N	2	2"	MAKE-UP CONTROL CONNECTION
P	1	4"	BLOW-DOWN CONNECTION

VESSEL DATA

DESIGN PRESSURE	160 PSIG	A.S.M.E. CODE	1977 ED
TEST PRESSURE	240 PSIG	CODE CERTIF.	REQ'D
DESIGN TEMP.	450°F	STATE REQMNTS.	~
		VACUUM DESIGN	NOT REQ'D
SHELL MATERIAL	A515 GR70	WELD EFF. SHELL	100%
HEAD MATERIAL	A515 GR70	WELD EFF. HEADS	100%
TYPE HEADS	2:1 ELL	STRESS RELIEVED	NOT REQ'D
CORROSION ALLOW.	1/16"	RADIOGRAPHED	100%

GENERAL NOTES

1. CONNECTIONS 2" AND SMALLER TO BE 3000# SCREWED COUPLINGS WELDED TO VESSEL.
2. CONNECTIONS 2½" AND LARGER TO BE 150# R.F. FLANGED.
3. INSULATION: 3" THICK WITH AL. JACKET

SHIPPING WEIGHT (ESTIMATED)

1. ACCUMULATOR 84400 LBS.
2. PIPING (INTERNAL) 4500 LBS.

DRAWN	Forney	1/5/78	VARIABLE PRESSURE ACCUMULATOR 140 - 40 PSIG	SCALE 1/8"=1'-0"
CHECK	[illegible]	[illegible]		JOB. NO.
CHECK				
APR			BOEING ENGINEERING AND CONSTRUCTION A Division of the Boeing Company	DRAWING NO.
APR				

Figure 3-20. Variable Pressure Accumulator Conceptual Design

Table 3-3. Variable Pressure Accumulator Conceptual Design Summary (Mechanical)

Nominal steaming rate	100,000 lb/hr
Storage time (full to empty)	0 25 hour
Vessel diameter	12 ft ID
Vessel length	62 ft
Metal wall thickness	¾ inch
Insulation thickness	3 inch
Weight:	
Shipping (estimate)	88,900 lb
Empty (@ 50 psig)	401,400 lb
Full (@ 140 psig)	426,400 lb

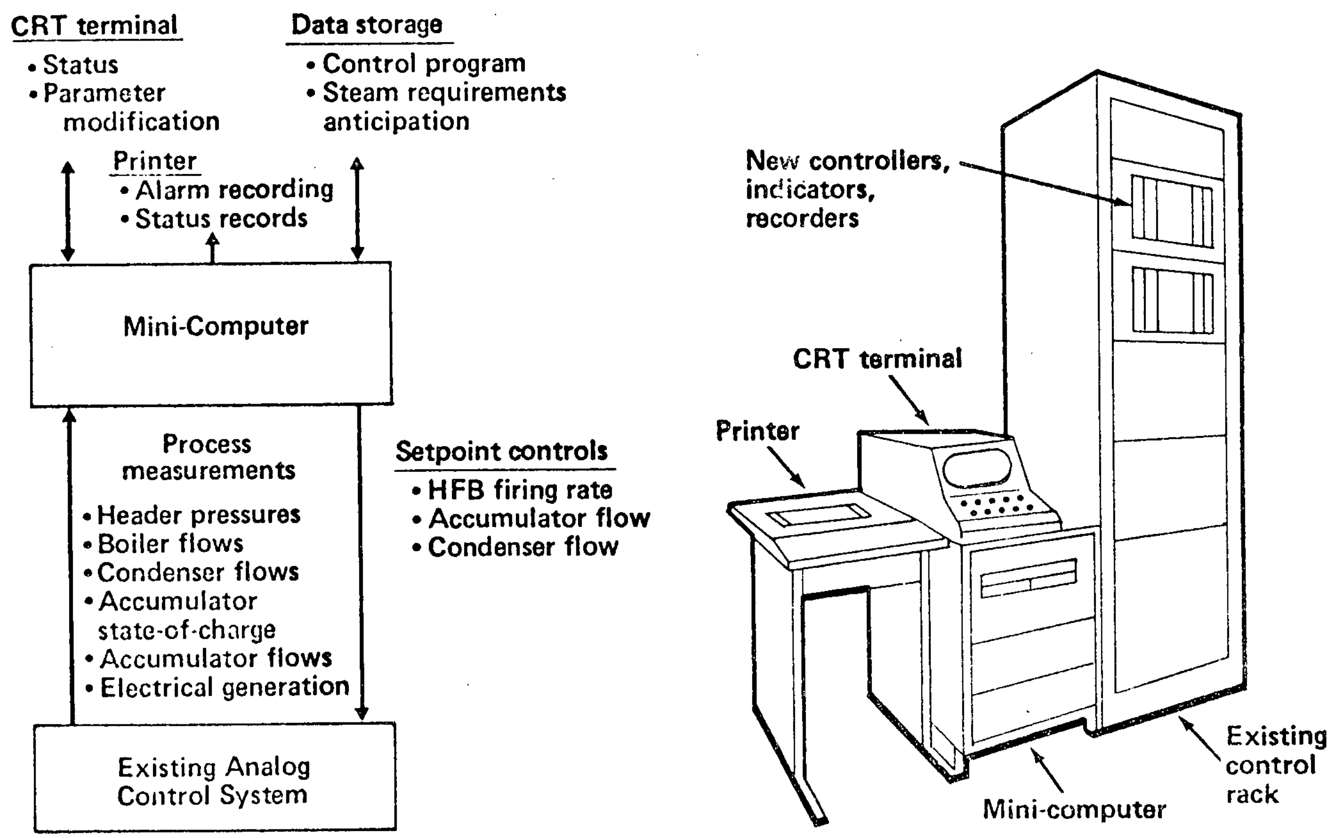


Figure 3-21. Control System Conceptual Design

The control system objectives and approach for the conceptual designs are presented in Tables 3-4 and 3-5. The general logic for the 140/40 psig variable pressure accumulator is given in Figure 3-22. An instrumentation schematic is shown in Figure 3-23. The data acquisition and computer control configuration is presented in Figure 3-24.

The cost estimates for the variable pressure accumulator conceptual design are presented in Table 3-6. The costs have been grouped into FOB costs and the more site specific field installation costs. The field installation cost estimates are based from estimating factors given by Guthrie[7] for process vessels. The control system cost estimate includes installation and test costs and is listed independently.

Constant Pressure Accumulator

The constant pressure accumulator conceptual design consists of an insulated pressure vessel, de-aerating heater, control system, valving, feedwater pump, and connections to existing steam heaters as shown schematically in Figure 3-25. The mechanical system design of the CPA is shown in Figure 3-26 and described in Table 3-7. The horizontally placed, insulating cylindrical pressure vessel has 2:1 ellipsoidal heads and is designed to ASME Boiler and Pressure Vessel Code, Section VIII, Division I.

Table 3-4. Data Acquisition and Control System Objectives

- Maintain header pressures within tolerance
- Minimize use of fossil fuel boiler
- Minimize steam venting
- Control hog fuel boiler firing rate, based on current steam requirements, accumulator state, and steam demand forecast
- Eliminate unnecessary use of condenser
- Maintain safe operation and alarm out-of-tolerance conditions
- Provide information on accumulator status and utilization
- Provide manual control capability
- Provide flexibility to evaluate variations in control strategy
- Provide reasonable cost, with potential cost savings for production versions

Table 3-5. Steam Accumulator Control System Approach

- Utilize existing instrumentation and controls where possible
- Utilize conventional analog controllers on individual loops to provide manual control capability
- Utilize minicomputer system for supervisory control of accumulator, condenser, and hog fuel boiler
- Write majority of software in high level language, such as Fortran, to reduce software development costs and facilitate modification of control algorithms. Production units could utilize microprocessor system to reduce costs
- Control fossil fuel boiler indirectly by supplying as much steam as possible from hog fuel boiler, thus minimizing 600 psig steam flow

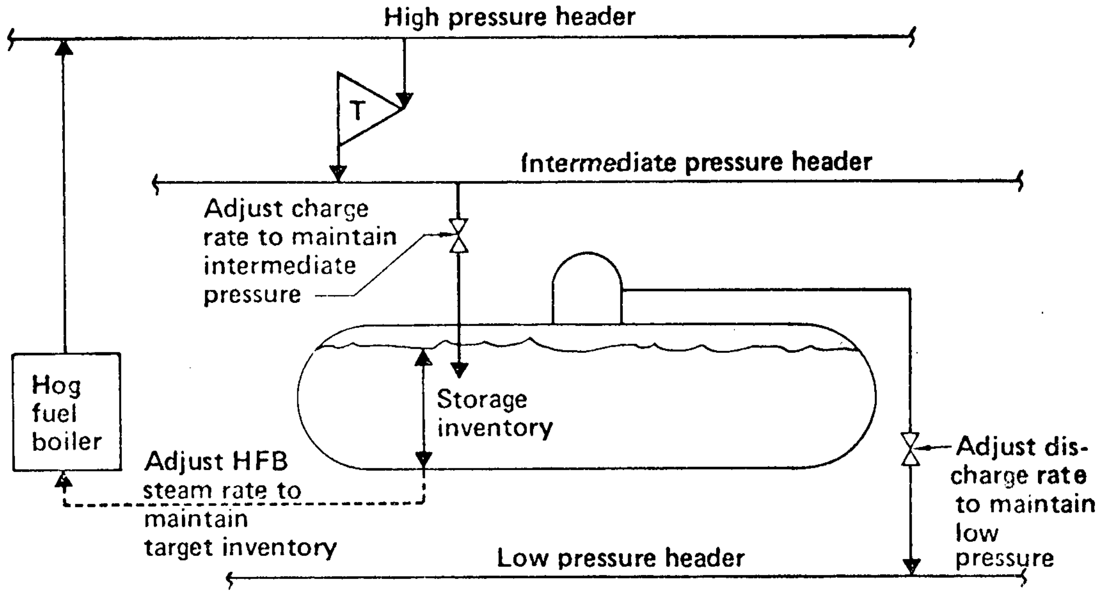
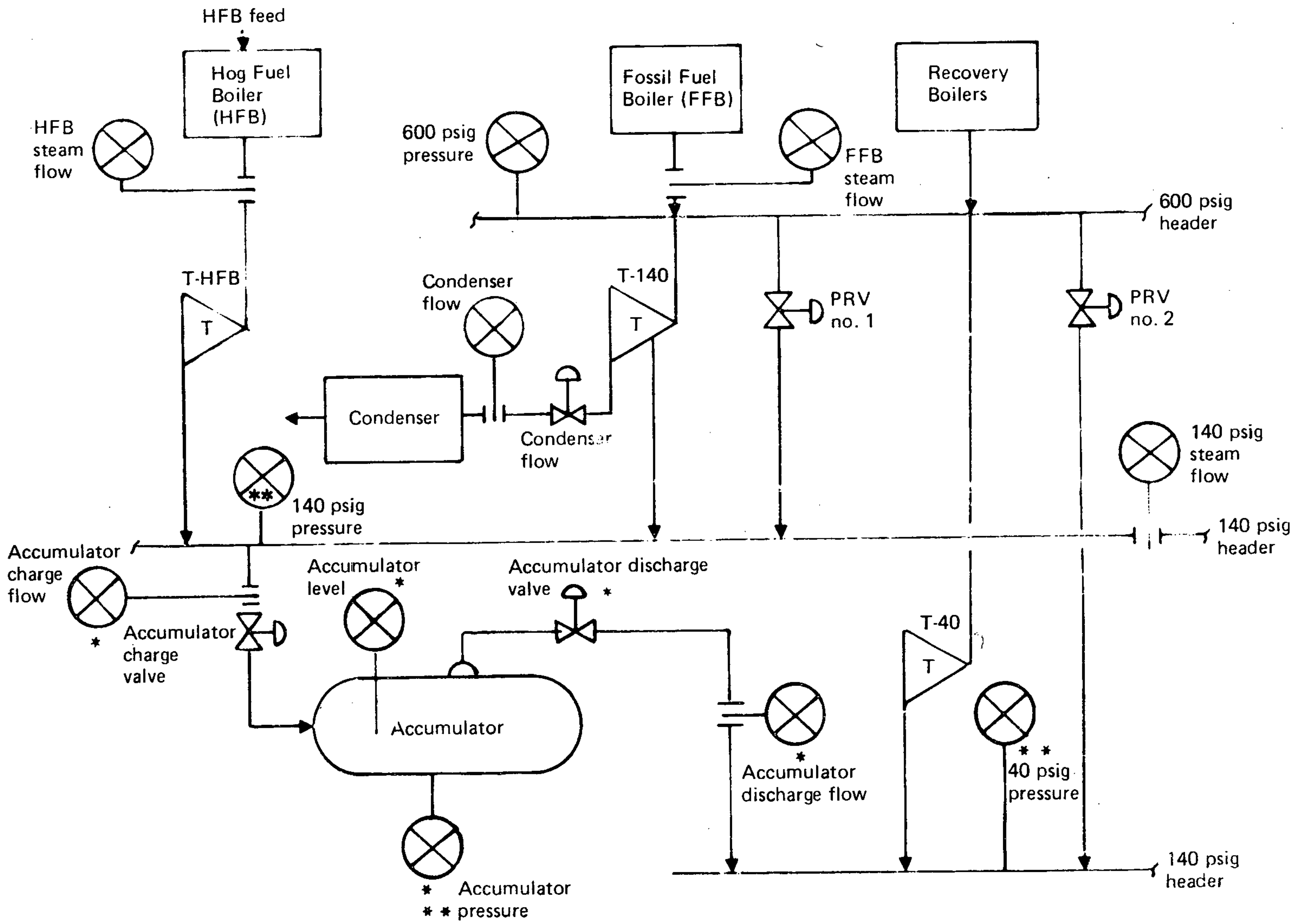


Figure 3-22. Variable Pressure Accumulator Control Concept



* New instrumentation/controls
** To indicator/controller on control panel

Figure 3-23. Variable Pressure Accumulator Instrumentation

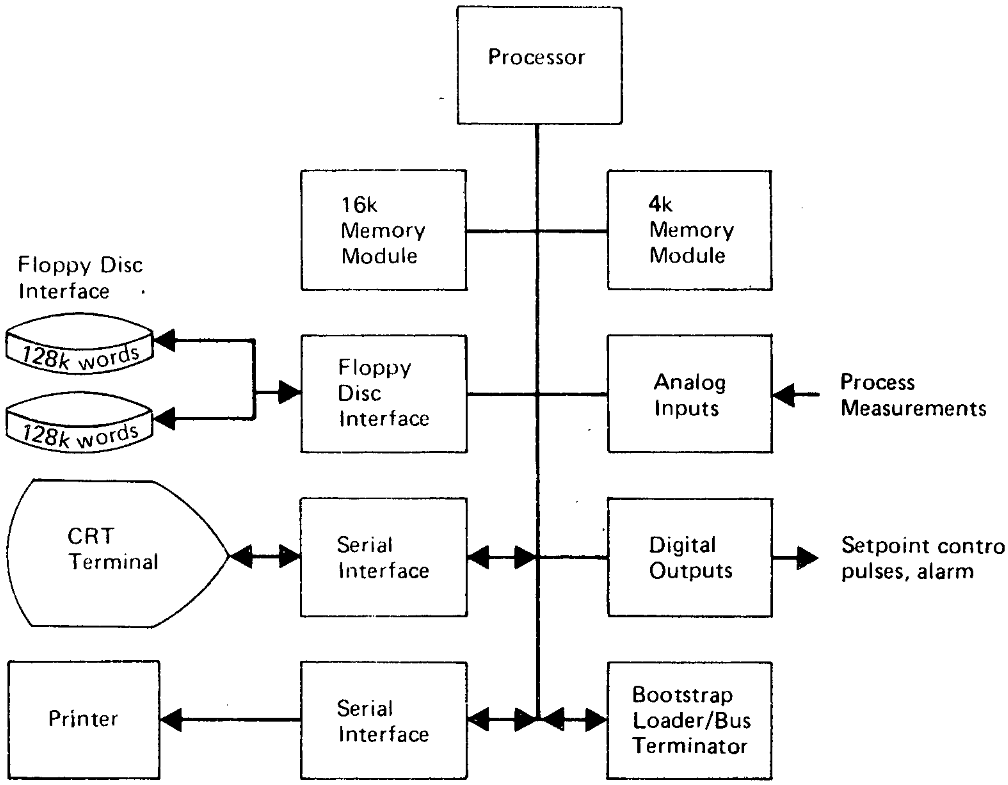


Figure 3-24. Data Acquisition and Control Computer Configuration

Table 3-6. Variable Pressure Accumulator Cost Estimates

Cost Account	140/40 psi Variable Pressure
Mechanical system	
Vessel & internal piping (1)	$ 72,000
Insulation (2)	20,000
Valves (2)	12,000
Subtotal	$104,000
10% Contingency	10,000
Total (FOB costs)	$114,000
Field installation (typical) (3)	
Direct material	75,000
Direct labor	73,000
Freight, insurances, taxes, other indirects	114,000
Total mechanical systems	$376,000
Control system (4)	$172,000
Grand Total	$548,000

(1) Based on vendor quotations

(2) Engineering estimates

(3) Based on Guthrie's estimating factors for pressure vessel installations

(4) Includes installation and test

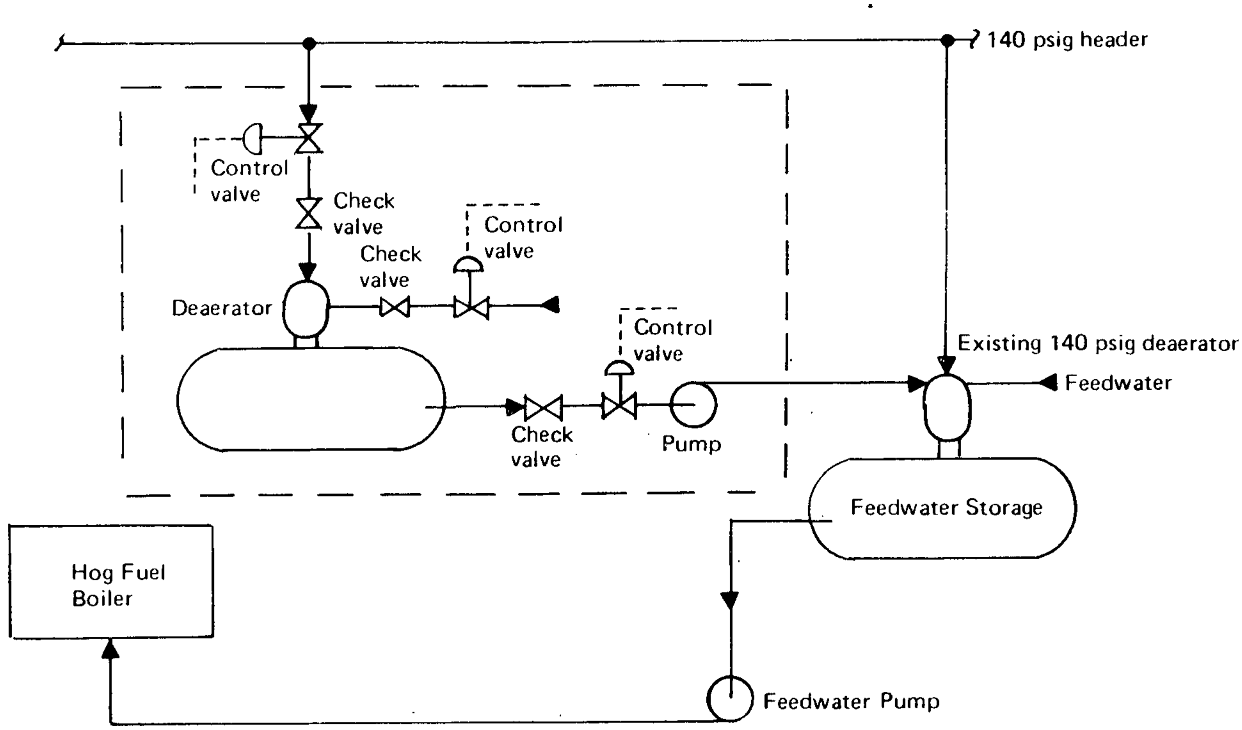
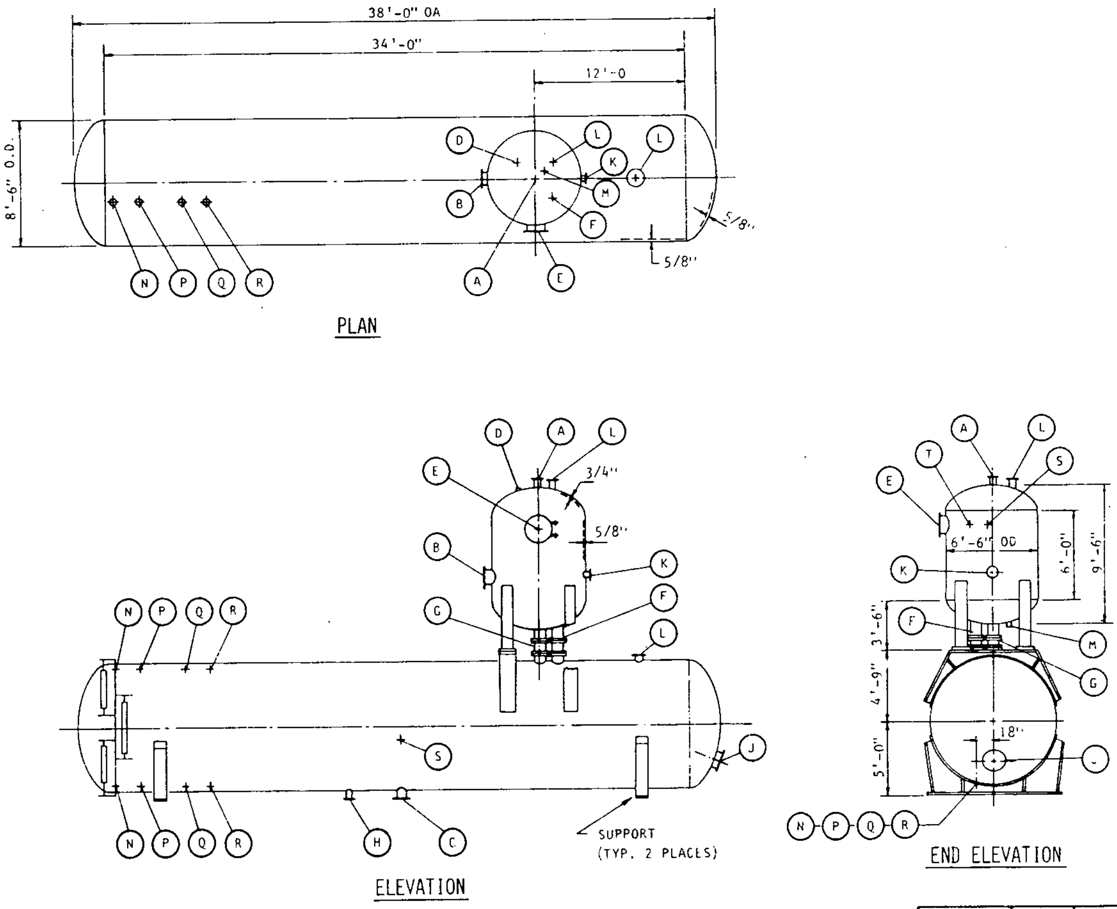


Figure 3-25. Constant Pressure Accumulator Installation Schematic



NOZZLE SCHEDULE			
MARK	QTY	SIZE	DESCRIPTION
A	1	6"	WATER INLET
B	1	10"	STEAM INLET
C	1	8"	FEEDWATER OUTLET
D	1	2"	RELIEF VALVE CONN
E	1	18"	MANHOLE
F	1	10"	EQUALIZER
G	1	10"	OUTLET TO ACCUMULATOR
H	1	6"	ACCUMULATOR DRAIN
J	1	16"	INSPECTION MANHOLE
K	1	3"	CONTINUOUS BLOWDOWN
L	2	6"	VACUUM BREAKER
M	1	2"	DEAERATOR DRAIN
N	2	1½"	GAUGE GLASS CONN.
P	2	1½"	LEVEL ALARM CONN.
Q	2	2"	OVERFLOW CONTROL CONN.
R	2	2"	MAKE-UP CONTROL CONN.
S	2	1"	THERMO CONN.
T	1	3/4"	PRESS. CONN.

VESSEL DATA

DESIGN PRESSURE	160 PSIG	A.S.M.E. CODE	1977 ED
TEST PRESSURE	240 PSIG	CODE CERTIF.	REQ'D
DESIGN TEMP.	450°F	STATE REQMNTS.	~
		VACUUM DESIGN	NOT REQ'D
SHELL MATERIAL	A515 GR70	WELD EFF. SHELL	100
HEAD MATERIAL	A515 GR70	WELD EFF. HEADS	100
TYPE HEADS -	2:1 ELL	STRESS RELIEVED	NOT REQ'D
CORROSION ALLOW.	1/16"	RADIOGRAPHED	100%

GENERAL NOTES

1. CONNECTIONS 2" AND SMALLER TO BE 3000# SCREWED COUPLINGS WELDED TO VESSEL.
2. CONNECTIONS 2½" AND LARGER TO BE 150# R.F. FLANGED
3. INSULATION: 3" THICK WITH AL. JACKET

SHIPPING WEIGHTS (ESTIMATED)

1. DEAERATOR 8800 LBS.
2. ACCUMULATOR 31200 LBS.

DRAWN	Dorney	1/5/78	CONSTANT PRESSURE ACCUMULATOR 140 PSIG, WITH DE-AERATOR	SCALE 1/8"=1'-0"
CHECK	P. Alar			JOB. NO.
CHECK				
APR			BOEING ENGINEERING AND CONSTRUCTION A Division of the Boeing Company	DRAWING NO.
APR				

Figure 3-26. Constant Pressure Accumulator Conceptual Design

Table 3-8. Constant Pressure Accumulator Conceptual Design Summary (Mechanical)

Nominal steaming rate	75,000 lb/hr
Storage time	0.275 hour
Vessel diameter	8.5 ft
Vessel length	38 ft
Metal wall thickness	½ inch
Insulation thickness	3 inch
Deaerating heater:	
Capacity (steam)	75,000 lb/hr
Heated water	301,000 lb/hr
Weight:	
Shipping (estimate)	40,000 lb
Empty (zero charge state)	50,000 lb
Full (full charge state)	133,000 lb

The de-aerating feedwater heater is a two-stage spray type heater of the type manufactured by Ecodyne Corporation/Graver Water Division. The deaerator operates as follows:

In the initial stage, the incoming water is sprayed into an atmosphere of steam where its temperature is instantly raised to within a few degrees of that of the steam. This spraying action results in the removal of almost all dissolved oxygen and carbon dioxide present in the feedwater.

The water then flows into the second stage of the heater where it comes into intimate contact with fresh steam. The steam scrubs the water vigorously heating it to steam temperature, thereby reducing the solubility of the corrosive gases. The steam then rises to the first stage of the heater carrying with it all remaining traces of non-condensable gases. It heats the incoming sprayed water and is itself completed condensed by the internal vent condenser. The condensed steam remains in the heater to be used as feed-water while the non-condensable, corrosive gases are vented free to the atmosphere.[(8)]

A feedwater pump is included to transport the stored preheated feedwater at the desired rate to the existing de-aerator/feedwater heating station within the process steam system. The constant pressure accumulator must be located about 60 feet above the feedwater pump inlet to maintain the desired back pressure on the pump. If the size of the accumulator were so large as to not be conveniently mounted in existing support structure, preferably near the existing de-aerator station, additional support would be required which could make the accumulator use less than desirable. However, it appears that the size of the CPA described herein could be located in the structure now supporting the de-aerator/feedwater storage at the Longview mill. The situation at other mills would have to be evaluated on a site specific basis.

As mentioned previously, the CPA is especially attractive at the Longview mill because of existing equipment. The existing de-aerator/feedwater heating station was oversized with the view to the future that a second hog fuel boiler would possibly be constructed. Connections exist on the feedwater storage tank for a second dearater should the second hog fuel boiler become a reality. Assuming a maximum of 550,000 lbm/hr for the existing hog fuel boiler, the existing de-aerator has an excess of approximately 80,000 lbm/hr steam acceptance capacity, i.e., the de-aerator could provide 864,000 lbm/hr heated feedwater instead of only 550,000 lbm/hr. This opens the possibility of using this excess to charge an accumulator which would be connected to the current feedwater storage tanks (see Figure 3-27). The existing feedwater storage tank could be used as an accumulator with some modification if the process steam system operators were confident the use of the level of the reserve hog boiler feedwater could be used to meet steam demand fluctuations by the CPA principle without jeopardizing the process system steam reliability. There is a justifiable reluctance to operate the steam supply system in such a manner that could possibly result in the under utilization of the hog boiler. Since this use of existing equipment may be unique to the Longview situation, cost estimates have proceeded assuming all the required equipment for a CPA would have to be installed as shown in Figure 3-25.

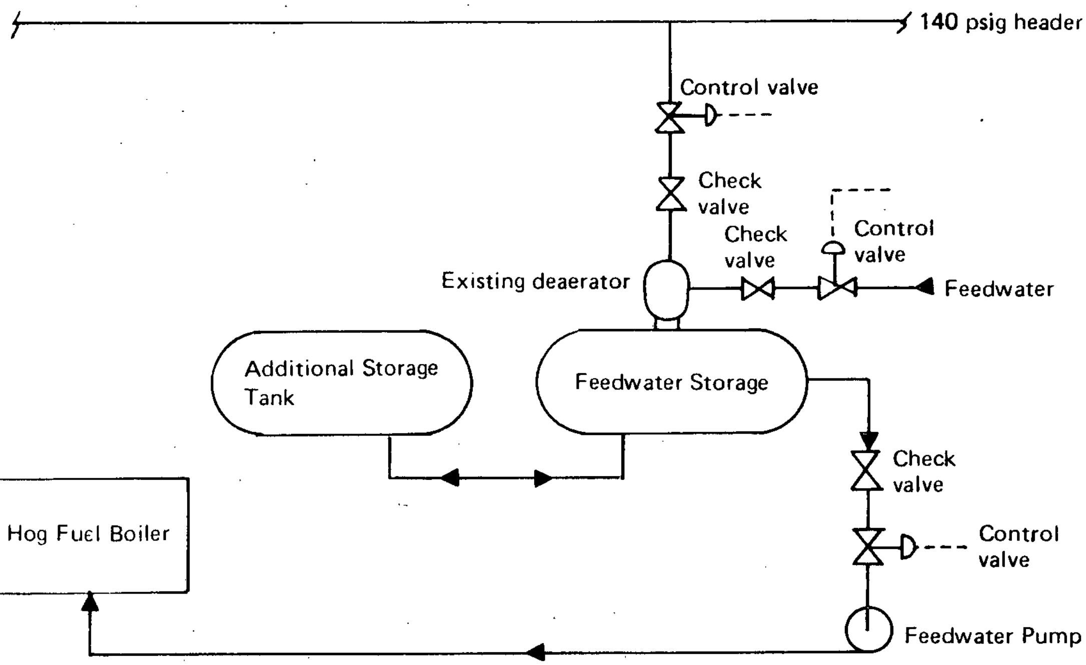


Figure 3-27. Potential Installation CPA Schematic for Longview Application

The control system for the CPA is very similar to that for the VPA, the only differences being in the measurement types and the valving. The general control logic for the CPA is shown in Figure 3-28. The instrumentation schematic for the CPA is given in Figure 3-29.

The cost estimate for the constant pressure accumulator conceptual design are presented in Table 3-8. Again, the costs have been grouped into FOB costs and the site-specific field installation costs.

3.4 EFFECT OF CONDENSER USAGE

The availability of turbine-generator condensers in the Longview powerplant presents the opportunity to use their steam absorbing capacity in swing smoothing. Normally, low cost hydroelectric power is expected to be sufficiently available from March to October to dictate shutdown of all the plant's generators. During the remainder of the year, back pressure power would be generated, while restricting condenser steam flow to its design minimum. The application of condenser swing smoothing requires that No. 4 turbine-generator (condenser flow: Min. 18,000 lb/hr, Max. 128,000 lb/hr) be operated the year around, while the remaining turbine-generators would operate during only one-half the year, as normal.

Swing smoothing would be accomplished by dumping excess steam to the condenser during periods of low demand while peaks in demand would be met by either reducing condenser flow, or increasing fossil firing rate. Two plant strategies were evaluated in model runs. In the first, various fossil

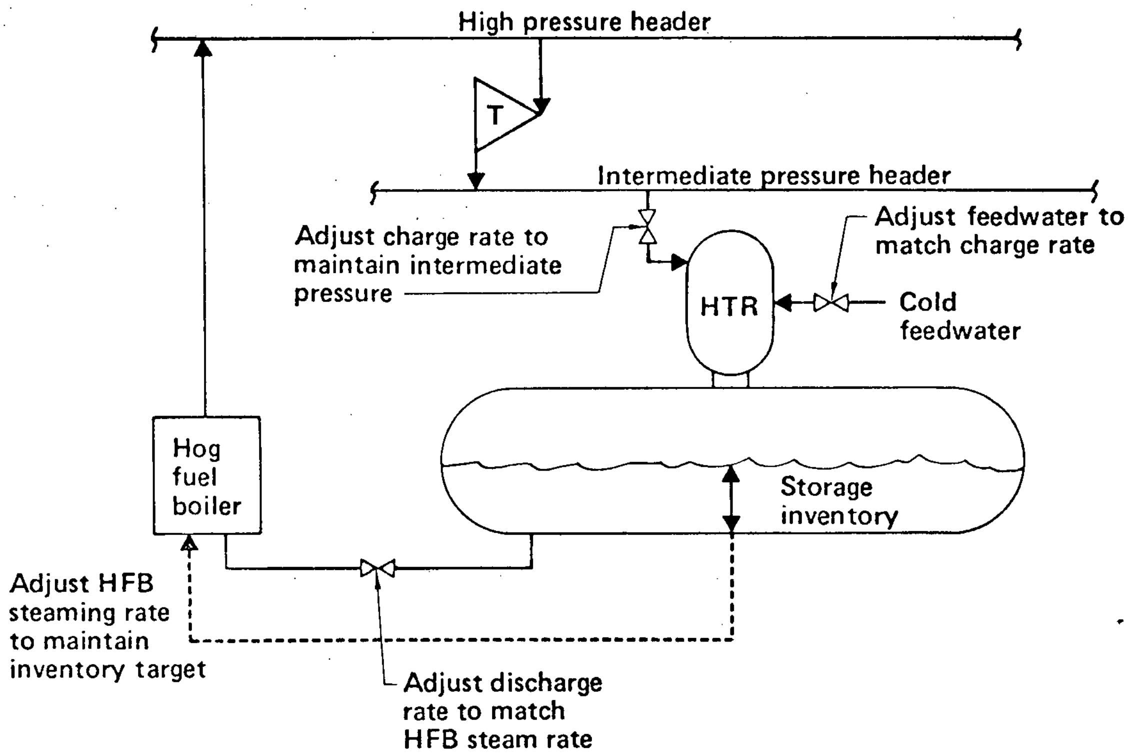


Figure 3-28. Constant Pressure Accumulator Control Concept

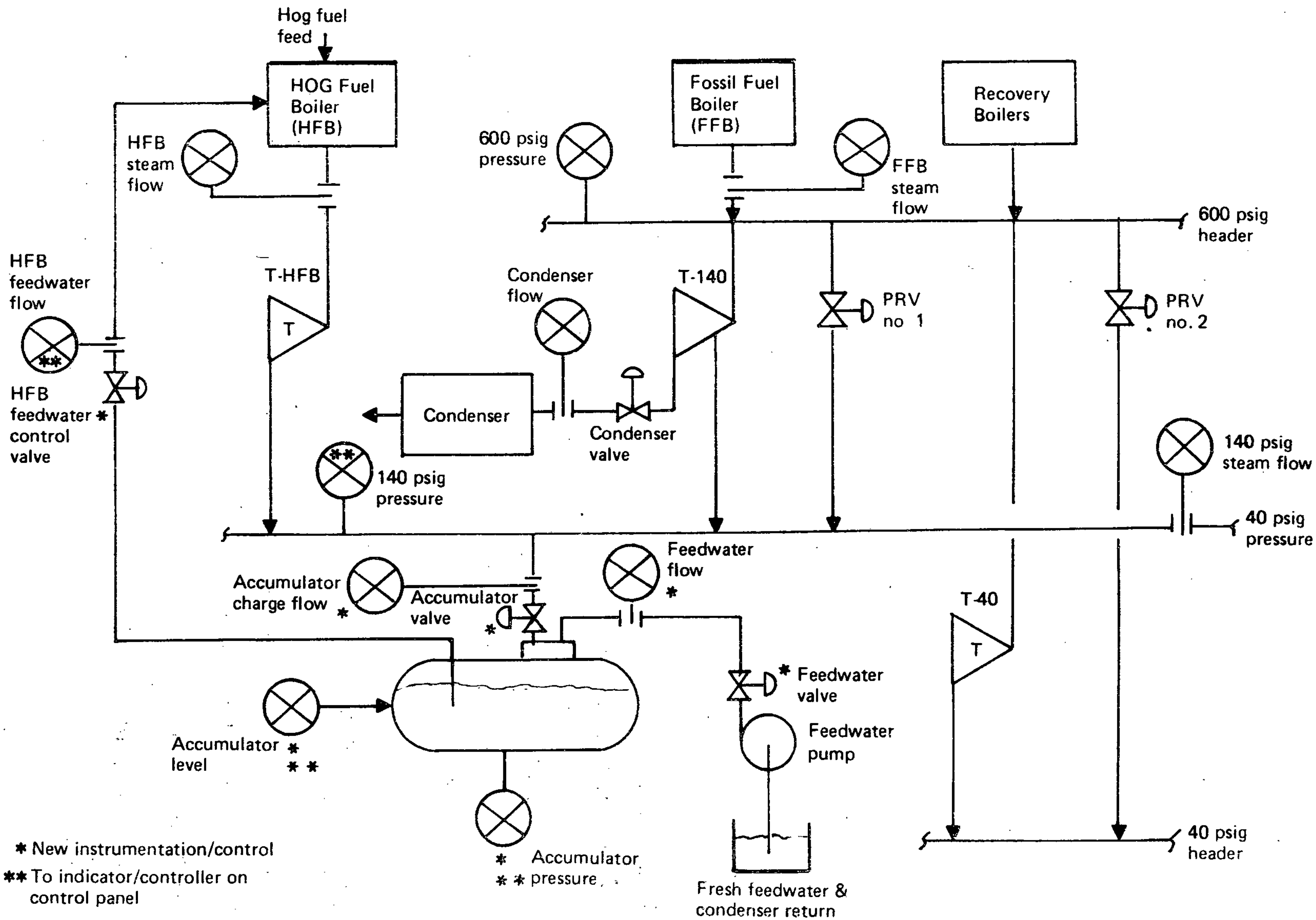


Figure 3-29. Constant Pressure Accumulator Instrumentation

Table 3-9. Constant Pressure Accumulator Cost Estimates

Cost Account	140 psi Constant Pressure
Mechanical system	
Vessel & internal piping (1)	$ 22,000
Deaerating heater (2)	52,000
Insulation (3)	8,000
Valves (3)	19,000
Feedwater pump (3)	7,000
Subtotal	$108,000
10% Contingency	11,000
Total (FOB costs)	$119,000
Field installation (typical) (4)	
Direct material	77,000
Direct labor	75,000
Freight, insurances, taxes, other indirects	118,000
Total mechanical systems	$389,000
Control system (5)	$172,000
Grand Total	$561,000

(1) Based on vendor quotations

(2) Based on vendor information

(3) Engineering estimates

(4) Based on Guthrie's estimating factors for pressure vessel installations

(5) Includes installation and test

steam rate targets were set, with no condenser flow target. This resulted in very high condenser flows and excessively high hog fuel consumption. Using the second strategy, various condenser flow targets were set, and the fossil steam flow was targeted at the fossil boiler's minimum rate. The results of model runs employing the second strategy are shown in Figures 3-30 through 3-33.

Figure 3-30 is a plot of steam and power production, actual condenser flow, and required hog boiler change interval as functions of condenser target. The fact that the required change interval never falls to 15 minutes is a consequence of the high charging rate capability of the condenser, and the fact that it does not store heat (never gets full). This figure displays condenser swing smoothing effects during the half year that in-plant power generation is desirable.

Figure 3-31 displays these effects during the half year that in-plant power generation would not normally be desirable. Electric generation rate and hog steam rate are both substantially lower, due to shutdown of all generators except No. 4. Fossil steam rate required remains the same as that seen in Figure 3-30.

Figure 3-32 plots the fossil steam reduction potential of condenser swing smoothing, against condenser target.

Figure 3-33 plots annual cost savings potential in Longview versus hog fuel cost. The value of electrical energy generated in-plant is expected to vary

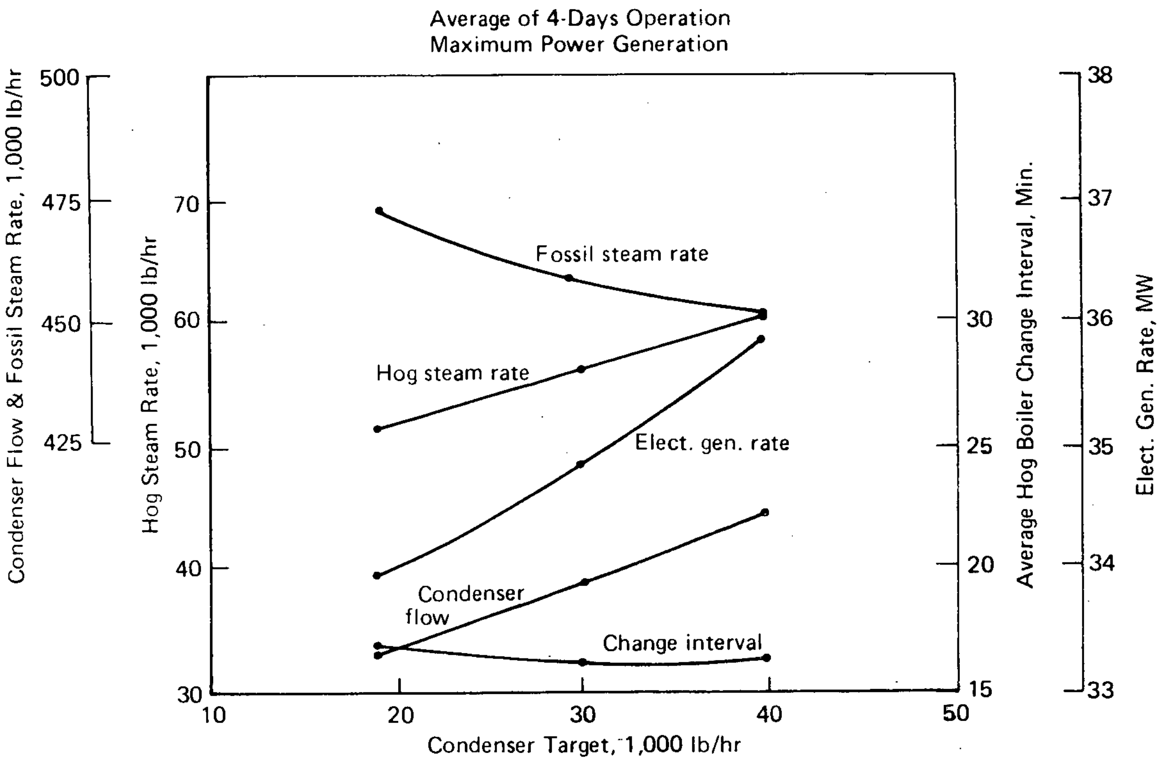


Figure 3-30. Longview Power Plant Model with Condenser Swing Smoothing - Process Analysis

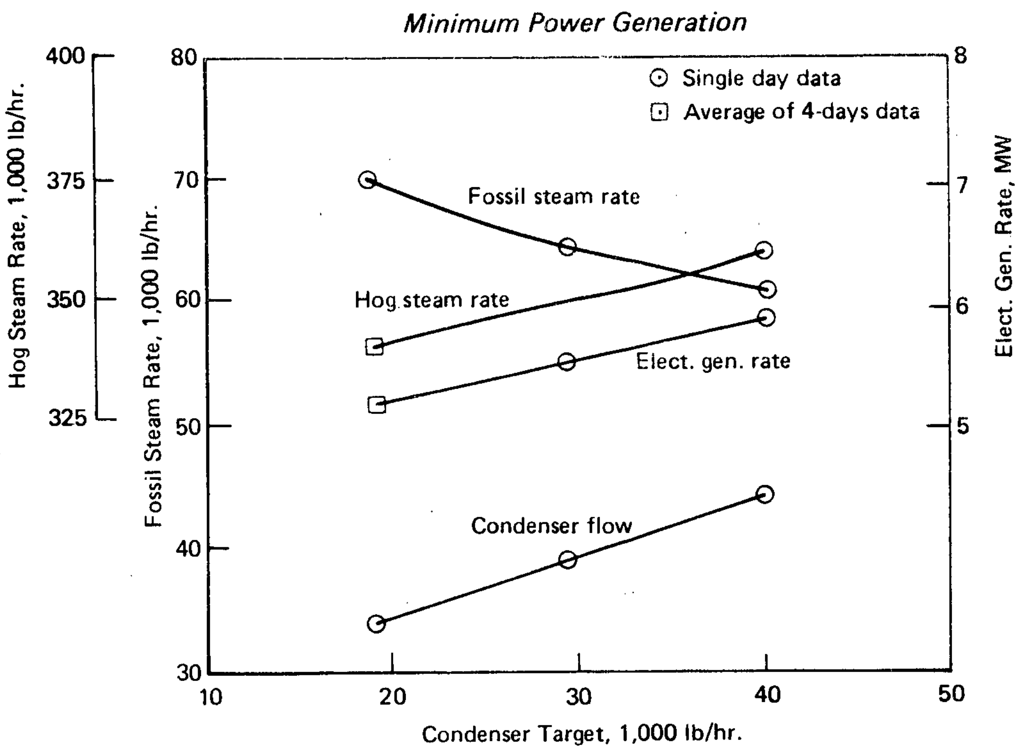


Figure 3-31. Longview Power Plant Model with Condenser Swing Smoothing

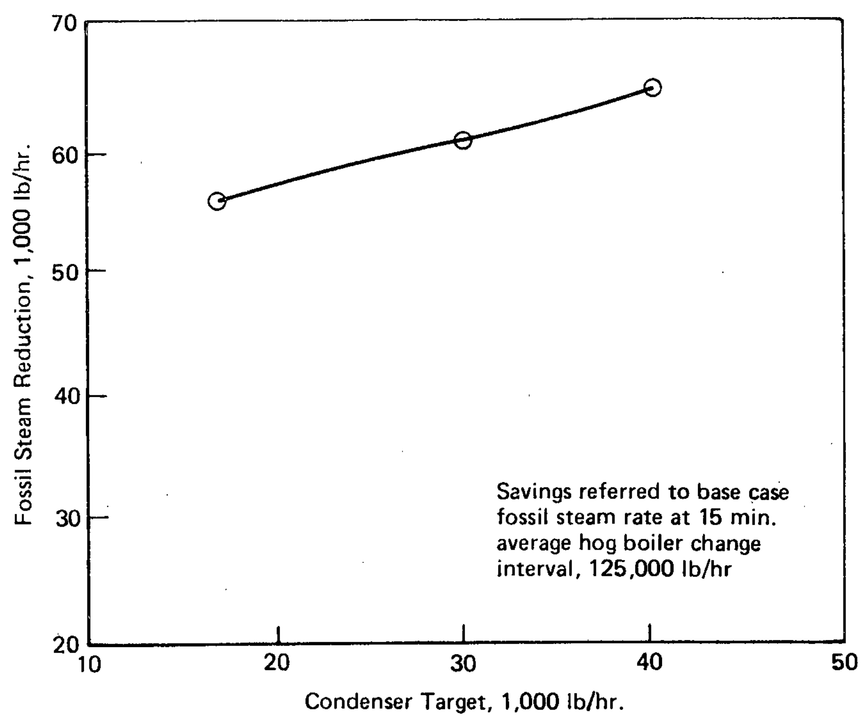


Figure 3-32. Fossil Steam Savings Potential with Condenser Swing Smoothing - 4-Day Average Performance

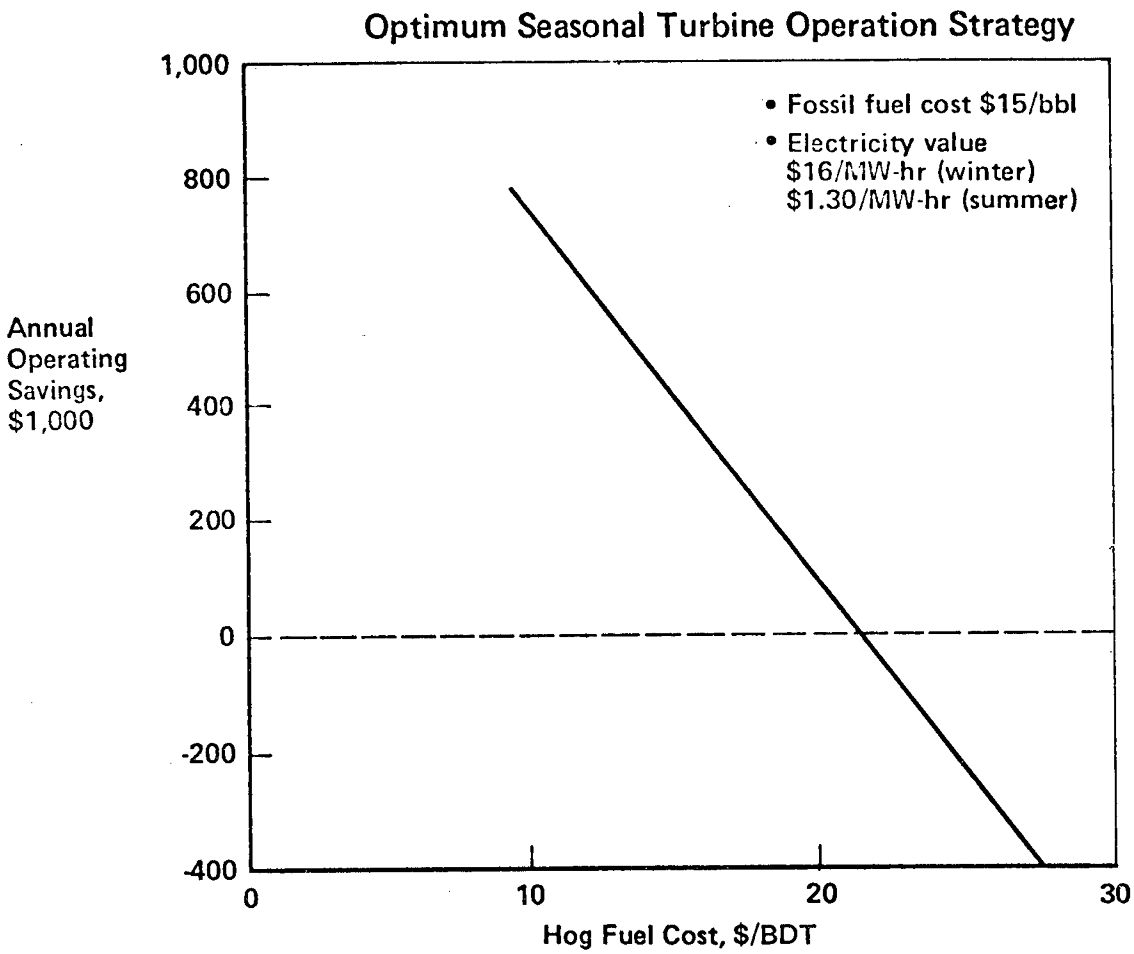


Figure 3-33. Condenser Swing Smoothing Savings

with availability of hydropower, from $1.30 to $16.00 per MW-hr. These figures are low by national standards, and have significant impact on calculated savings. This indicates that condenser swing smoothing, applied to mills experiencing more typical power costs, will be substantially more attractive than at Longview. At this site, at projected hog fuel cost of $25/ton, condenser swing smoothing operating costs exceed the base case.

4.0 ENERGY RESOURCE IMPACT SUMMARY

The impacts expected to arise from wide scale implementation of TES in the U.S. Paper and Pulp Industry have been assessed. Areas that were considered were energy resource, market penetration, and legal/financial/environmental/other impacts. Information on fuel availability and price information and background on noneconomic impacts and factors were gathered to develop a commercialization plan for this TES application.

The majority of this assessment was accomplished by SRI International under subcontract to Boeing. The specific areas considered were:

- o Resources impact analysis
- o Parametric economic analyses
- o Characterization of market forces
- o Market penetration rates
- o Environmental impacts
- o Other impacts and influences

BEC and Weyco supplied SRI with preliminary data on the TES application in the Longview plant. The American Paper Institute (API) supplied Weyco with a listing of its members who now use some hog fuel. Weyco, in turn, conducted telephone interviews with responsible individuals at more than half of those plants to determine their interest in the TES concept; limitations on its use (such as unavailability of hog fuel or boiler capacity to burn this waste); and the amount of steam generation of each plant might shift from its gas- or oil-fired peaking boilers to the slower burning hog fuel, given a TES system that would allow the swings in steam demand to be met by this solid fuel burning on a grate. The results of the Weyco interviews and the survey (see Section 2.3) were supplied to SRI for its use in preparation of the resources and air quality impact estimates.

Other major data sources used by SRI include:

1. Characterization of the U.S. pulp and paper mills
   - o Post's 1978 Pulp and Paper Directory

     1977 Directory of the Forest Products Industry
   - o Lockwood's Directory 1977
2. Estimation of the wood waste that might be available for use as hog fuel by the candidate mills
   - o Crop, Forestry and Manure Residue Inventory-Continental United States - SRI Project 5093 - June, 1976 - Data Base Developed for the National Science Foundation
3. Regional particulate and SO_2 emission limits; location and fuel use patterns of the utilities selling electricity to the candidate mills; historical industrial electricity, gas, and oil prices.
   - o Energy Supply and Demand Situation in North America to 1990 SRI Project 2177 - December, 1974 - A Private Multi-Client Study
4. Overview of the pulp and paper industry and its power generation practices
   - o The Paper Industry - A Clinical Study - John G. Strange

The research approach began with the compiling of selected data and information from these major sources and from trade periodicals. Tentative conclusions drawn from analysis of the compiled data were then modified or substantiated by additional literature search and discussions with BEC and Weyco. Credible limits on the economic variables were established on the general basis of SRI experience with energy conversion systems. These limits were used as inputs to an economic sensitivity methodology developed by BEC. This methodology yielded an economic index in the form of the price that could be paid for wood waste used as hog fuel with the TES system in use.

The details of this impact assessment are presented in Appendix C. The major conclusions drawn from this assessment are:

1. This TES application will allow a ten percent shift in steam generation from gas and oil to hog fuel and coal in about 100 integrated pulp and paper mills. This shift in fuel type can save the equivalent of eight million barrels of heavy fuel oil per year.
2. The additional cogeneration expected to accompany this shift in steam generation can reduce the electricity now purchased by these pulp and paper mills from utilities by an amount equivalent to an additional 6 million barrels of heavy fuel oil each year. The combined savings at the mills and their supplier utilities is equivalent to about 18 million barrels of oil per year by the year 2000.
3. The displacement of gas and oil will decrease the national sulfur dioxide (SO_2) emissions, however; this benefit will be partially

offset by an increase of the nation's emissions of particulates. More than two pounds of SO_2 will be removed for each pound of particulates that are added.

4. Industrial electricity, oil, and gas price increases will supply strong incentive for increasing hog fuel and coal usage through plant modifications such as TES systems.
5. Restraints on industrial gas usage and interruptions of industrial electricity supply will supply strong incentive to this shift in power generation.
6. Utilities are being directed and encouraged to participate in industrial cogeneration, and this will supply incentive to this TES application.
7. Legal and societal barriers to this application of TES and its shift of power generation to hog fuel and coal appear to be minimal and resolvable.

5.0 COMMERCIALIZATION PLAN

The objective of the commercialization analysis task is to develop a plan for expediting the installation of swing-smoothing thermal energy storage systems throughout the paper and pulp industry wherever the economics of such installations prove attractive. The approach taken is to consider two parallel program elements; a D.O.E. Demonstration Program, and an Industrial Implementation Program. The first of these elements is aimed at providing an example of fossil energy savings in a typical industry environment, coupled with demonstrated economic advantages. This solid evidence of technical and financial feasibility is believed necessary to obtain industry decisions for proceeding with commercial installations. The second of these elements will identify potential users, (both companies and specific plants), of swing-smoothing thermal energy storage systems and develop their awareness of the benefits to be gained. As a result of this activity, a number of candidate mills could be expected to move rapidly towards implementation upon satisfactory completion of the demonstration program.

5.1 ECONOMIC FEASIBILITY

Since commercialization will ultimately depend on economic feasibility, this subject will be discussed first.

The economics of swing-smoothing installations depend on the performance factors of:

- o Thermal load transfer from fossil to hog fuel

- o Any incremental electric power generation associated with the load transfer

and the economic factors of:

- o Fossil fuel price
- o Hog fuel price
- o Electrical power value
- o Capital costs of the swing-smoothing installation
- o Amortization schedule
- o Tax considerations

An annual return, or cost benefit, associated with thermal load transfer can be expressed in terms of these factors and plant operating characteristics:

Return	=	Value of fossil fuel saved	+	Value of incremental electrical power generated	-	Cost of incremental hog fuel consumed	-	Cost of incremental O&M required

or,

$$R = C_F \frac{Q}{E_F} + CpE - C_H \quad \frac{Q}{E_H} + \frac{3.412\ E}{E_H E_P f} - (O\&M)$$

where,

R = Annual return, \$/Yr

Q = Process thermal load transferred from fossil to hog fuel, $\$/10^6$ BTU

E = Incremental electrical energy generated, MW-hr/yr

C_F, C_H = Fossil and hog fuel prices, $\$/10^6$ BTU

C_F = Electrical energy value, \$/MW-hr

E_F, E_H = Efficiencies of fossil and hog fuel steam generation

E_p = Efficiency of electrical power generation

f = Net/gross electrical generation ratio

O&M = Incremental operating and maintenance costs, \$/Yr (Considered to be zero for typical mills.)

The annual thermal load transfer is related to the hourly fossil steam rate reduction:

$$Q = \frac{\dot{W}_f \times h_f \times 8760 \times K}{10^6}$$

where,

$\dot{W}_F$ = Reduction in fossil steam rate, lb/hr

h_f = Enthalpy added to feed water by the fossil boiler, BTU/lb

K = Fraction of year when thermal load transfer is accomplished.

The annual increment in electrical energy generated is related to the incremental electrical power generation rate, P:

E = P x 8760 x K

The annual return can be combined with the investment and tax considerations to calculate a return on investment. By definition, the discounted cash flow rate of return on investment is the discount rate (percentage) that makes the present value of the investment equal to the present value of the cash flow resulting from the investment.

For an investment period of n_1 years and an operating period of $(n_2 - n_1)$ years, the after-tax R.O.I. is therefore the value of i that satisfies the following equality:

$$I_{net} \times \frac{1-(1+i)^{-n_1}}{i} = C.F. \times \frac{1-(1+i)^{-(n_2-n_1)}}{i} (1+i)^{-n_1}$$

where,

I_{net} = (1 - Invest. Tax Credit) x I_{gross}

= 0.90 I_{gross} for 10% Invest. Tax Credit

C.F. = (Return - Depreciation) (1 - Tax Rate) + Depreciation

= $\frac{1}{2}$ $(R + \frac{I}{n_2-n_1})$ for 50% tax rate and straight line depreciation

Figure 5-1 shows the after-tax R.O.I. as a function of annual average thermal load transfer and hog fuel cost. This plot is for conditions considered typical of the industry and shows that an estimated threshold value of 15% is exceeded for marginal hog fuel costs as high as $30/BDT (bone-dry ton) and thermal load transfers as low as 35,000 lb. steam/hr. on an annual average basis. Escalation of the fossil and hog fuel prices would increase the R.O.I. at any given set of parameters.

The data of Figure 5-1 are for the case of no incremental power generation. This situation will be the norm where turbine generators are not installed, or where turbine throttle control is used to regulate the process steam header pressure. At the Longview mill several factors combine to produce a net electrical generation increment with a storage system. These are the

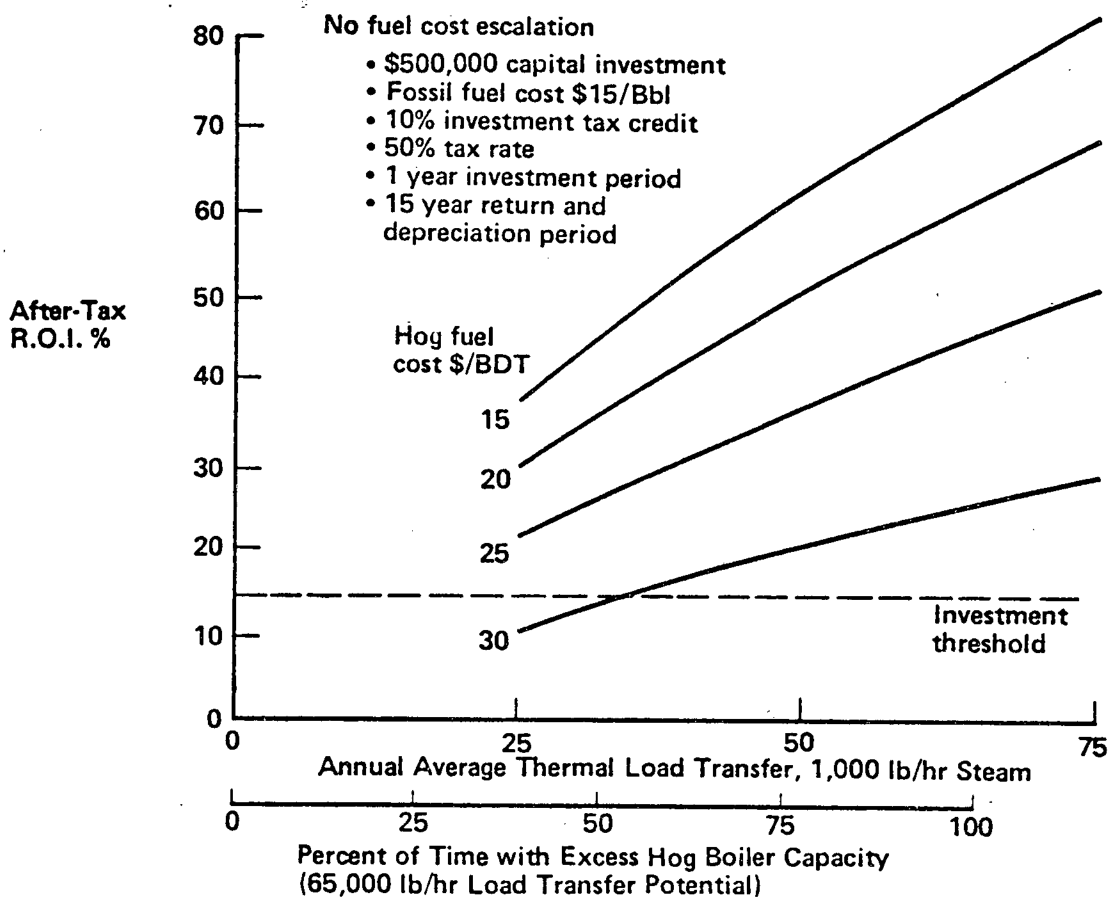


Figure 5-1. Return on Investment — No Incremental Electrical Generation

higher enthalpy of the hog fuel-generated steam (1250 psi) than the fossil fuel-generated steam (600 psi), resulting in a lower heat rate for the hog-fuel-steam turbine, and the use of pressure regulating valves rather than turbine throttle control for process header pressure control. As shown in the performance plots in Section 3.2, the incremental electrical power generation rate is in the order of 3 to 4 MW. However, the potential economic impact of this bonus is not large at Longview due to the very low value of purchased hydroelectric generated electrical energy at this mill - on the order of $16/MW-hr in winter and $1.30/MW-hr in summer. As a result, the mill does not cogenerate electricity in summer in years of normal stream flow.

For other locations with more nearly national average electrical power rates, any incremental cogeneration will further improve the R.O.I. values shown in Figure 5-1. The values as shown are therefore conservative, and even so, demonstrate the highly attractive economics of thermal energy storage for swing-smoothing, given the availability of excess hog fuel steam generation capability to accept load transfer from the fossil fuel boilers.

5.2 COMMERCIALIZATION PROGRAM SUMMARY

The phasing, duration, and key milestones of the major activities encompassed by a two-element commercialization program are shown in Figure 5-2. This program reflects the fact that technology development is <u>not</u> required to implement thermal energy storage for steam demand swing-smoothing in the paper and pulp industry. However, hard evidence of economic benefits is considered necessary to stimulate industry acceptance of this fossil fuel-conserving operating feature. The current availability of technology implies the potential for early demonstration and rapid industrial installation of these systems, and the program has accordingly been designed to expedite the commercialization process as much as possible. This vigorous approach is necessary to preserve and take advantage of program momentum in order to realize significant fossil fuel savings at an early date.

5.2.1 D.O.E. Demonstration Program

The demonstration program shown in Figure 5-2 is a generalized plan with timing considered reasonable for a typical mill selected as the demonstration site. Initial activity is a seven-month design program that includes data collection and storage system performance analysis made necessary by the non-availability of the Longview mill for an early demonstration program. (There is uncertainty as to the timing of the hog boiler steam rate improvement program at Longview.) This analysis will utilize the Longview Plant math model developed in this study, suitably modified to represent the selected mill. Based on this analysis, a preliminary design will be prepared and specifications written to guide the fabrication, installation, and test of the demonstration system. This phase involves no hardware procurement and funding will be sought from D.O.E.

Following completion of the demonstration system design phase, work would begin to implement the design at the demonstration site. The availability of all requisite technology permits an overall construction schedule of nine months from specification approval to checkout of the installation.

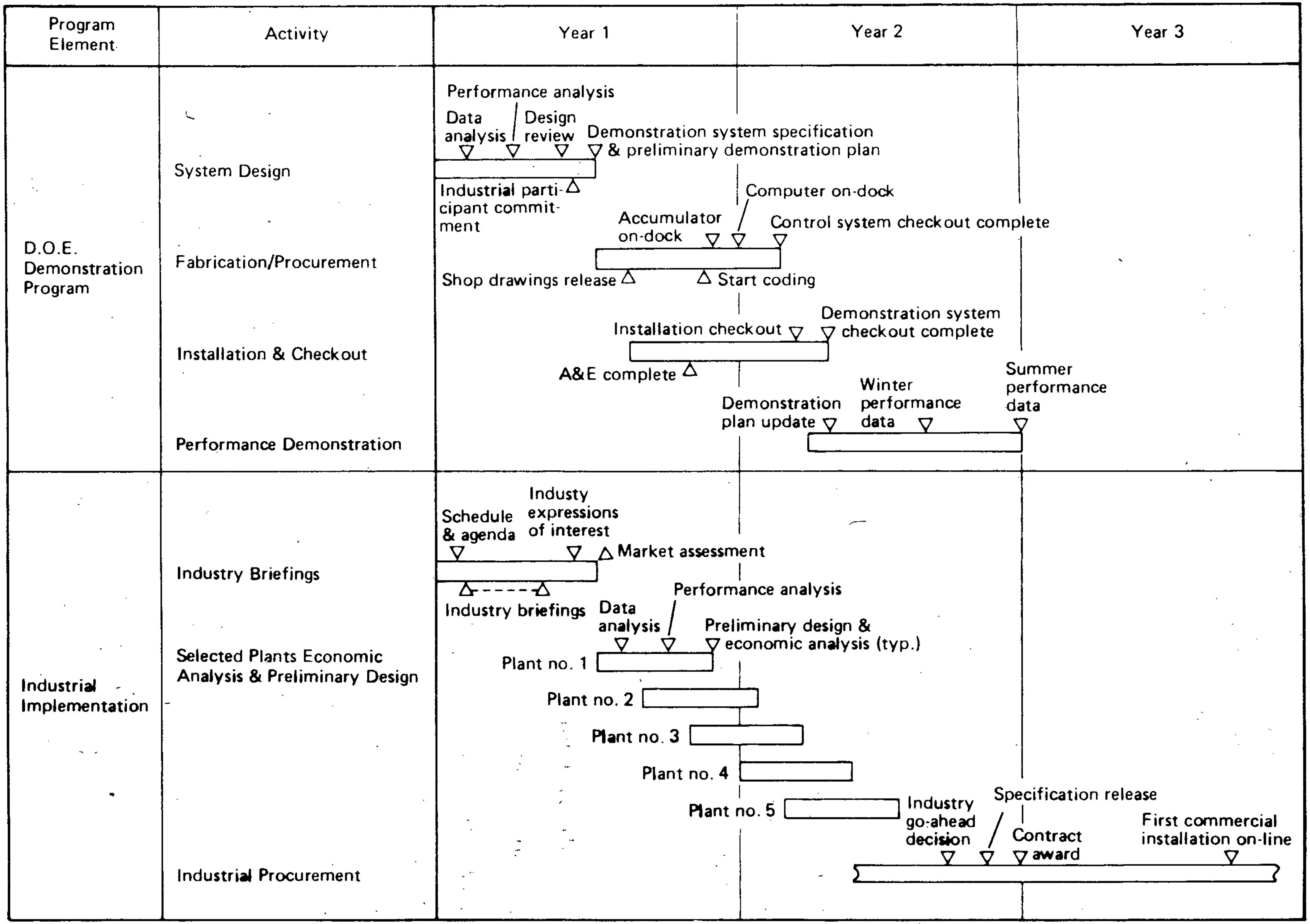


Figure 5-2. Commercialization Plan Activity Phasing

Funding of these activities including hardware procurement will be the joint responsibility of D.O.E. and the industrial participant. The basis for this joint funding will be determined during the system design activity.

System demonstration activity per se consists of recording and analyzing steam flow and electrical generation data during normal plant operations. Since this activity is not planned as a dedicated testing program, it can extend over a sufficient time period to determine seasonal effects at modest cost. Funding of this activity will involve both D.O.E. and the industrial participant, with D.O.E. responsible for the demonstration-peculiar equipment, materials and labor, while the industrial participant will conduct normal operations of the system at no cost to D.O.E.

5.2.2. Industrial Implementation Program

The Industrial Implementation Program is shown in parallel with the D.O.E. Demonstration Program in Figure 5-2. Initial activity is an industry briefing program conducted in parallel with the demonstration system design activity. The purpose of these industry briefings is to make the industry thoroughly aware of the D.O.E. program, including the encouraging results achieved in Phase I and the work that will be ongoing in pursuit of system demonstration. The activity will be focused on mills identified in the industry survey described in Section 2.3 as candidates for steam swing-smoothing via thermal energy storage. Plant modification decisions depend typically on both corporate and plant manager approvals, hence, it is important to take these briefings to the mills, rather than restricting them to company headquarters facilities. It is expected that the industry response to this information dissemination activity will be expressions of interest for detailed analyses of economic feasibility for at least five candidate mills. This more detailed interaction with the industry will also permit a more knowledgable assessment of total market potential, hence fossil energy conservation, than was possible in the Phase I study. Since this activity does not involve any industrial participant, it will require full funding by D.O.E.

The industrial implementation program continues with a series of preliminary analyses of specific mills nominated by industry as a result of the briefing program. These analyses will be conducted while the demonstration system is being fabricated and installed.

These analyses will make use of the math model, with suitable modifications to represent each mill, to size storage systems and estimate the fossil/hog fuel transfer potential. It is proposed that these analyses be jointly funded by the industrial participants and D.O.E. Each participant would be responsible for collecting the required plant data and providing technical support for modeling plant operations, in a manner similar to the Weyerhaeuser unfunded participation in Phase I. D.O.E. would fund the actual data analysis effort.

This cadre of mills would then be expected to proceed independently to implement thermal storage swing-smoothing systems starting with initial release of demonstration system results. As a result, what might be called D.O.E. - stimulated, but purely commercially designed, fabricated and installed systems could be coming on-line within three years. The impetus of this initial group of installations would then be expected to stimulate further industry implementation.

5.3 FOLLOW-ON PROGRAM PLAN

Phase II of the D.O.E. program in thermal energy storage applications (in the paper and pulp industry), is recommended to include activities in both the Demonstration and Industrial Implementation programs as summarized in Figure 5-2 and Section 5.2 above.

A schedule and task outline for the initial effort in each of these activities is shown in Figure 5-3. At the conclusion of this phase, D.O.E.'s position with respect to the overall program will be as follows:

- The demonstration program will be ready for implementation, with system and hardware specifications in hand and refined cost estimates available.
- A firm understanding of the programs' contribution to fossil energy conservation will have been established in terms of (1) the near-term market size, and (2) the probable rate of industrial implementation.
- Approximately five candidates for early implementation following the demonstration program will have been identified.

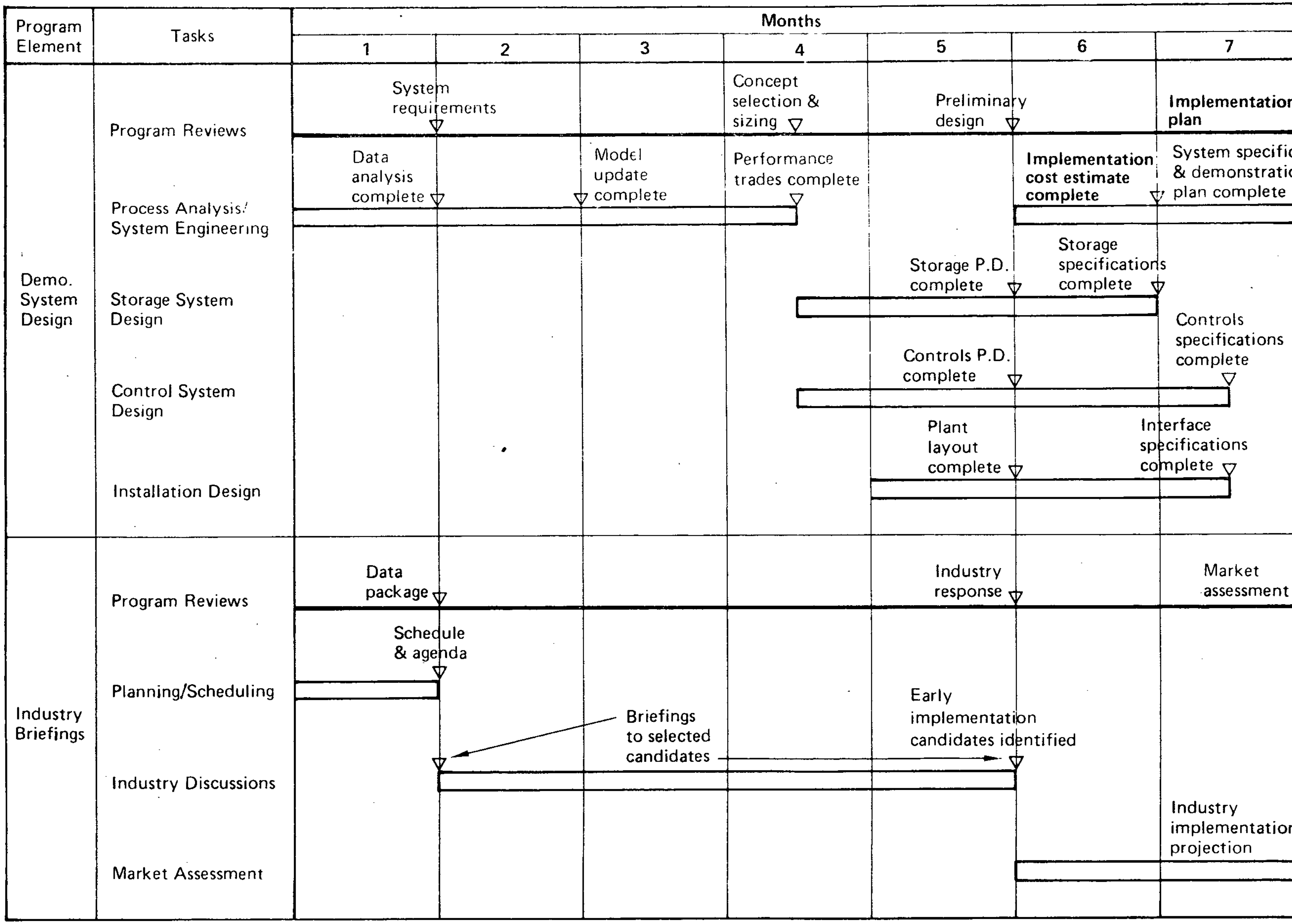


Figure 5-3. Phase II Program Plan - Initial Activity

Appendix A

LONGVIEW PLANT DATA

A.1 STEAM PLANT OPERATING DATA

Tables A-1 through A-5 describe boiler and turbine capabilities, feedwater heating arrangements, steam header conditions and fixed steam loads.

A.2 PLANT ENERGY FLOWS

Tables A-6 through A-10 tabulate historical and future energy flow data.

A.3 STEAM REQUIREMENTS FOR POWER GENERATION

This section shows the method used to calculate power output corresponding to process steam demands.

A.4 STEAM SWING DATA

Swinging demand data are shown.

TABLE A-1 BOILER CHARACTERISTICS

BOILERS

NUMER	TYPE	STEAM FLOW 10^3 LB/HR MAX	BASE	MIN	PRESSURE PSIG	TEMP OF	ENTHALPY Btu/LB
1	Red Liquor	130	110	80	600	700	1351
2	Recovery						
6	Hydrogen	40	40	40	"	"	"
	Oil/Gas	100	0	0*	"	"	"
7	Oil/Gas	200	0	50	"	"	"
8	Oil/Gas	250	0	120	"	"	"
9	Oil/Gas		0	50	"	"	"
10	Black Liquor	500	400	300	"	"	"
	Recovery						
11	Hog Fuel	550	550	200	1250	935	1458

*Assumes H_2 firing at minimum boiler steaming rate.

TABLE A-2 TURBINE CHARACTERISTICS

NO.	RATING MW	STEAM FLOWS 10^3 LB/HR MAX INLET	140 PSIG BLEED	40 PSIG BLEED	2" HG CONDENSER	STEAM ENTHALPY, BTU/LB 140 PSIG	40 PSIG	2" HG
1	5	200	(1)	(1)	-	1264	1212	-
2	5	200	(1)	(1)	-	1264	1212	-
3	15	240	-	0-222[2]	18[2]-124	-	1212	1062
4	15	450	0-245	0-224[3]	18[3]-128	1264	1212	1062
5	30.4	550	550	-	-	1287	-	-

1 - Data not available

2 - Maximum 40 LB + condenser flow = 240,000 LB/HR

3 - Maximum 40 LB + condenser flow = 242,000 LB/HR

TABLE A-3 BOILER FEEDWATER SYSTEM CHARACTERISTICS

FEEDWATER DATA

	TEMPERATURE	FLOW	ENTHALPY	PRESSURE	
	F	10^3 LB/Hr	Btu/LB	PSIG	IN Hg
CONDENSATE					
STORAGE					
Process returned condensate	260	490	228	20	-
40 PSIG					
DEAERATOR					
Make up	76	-	44	-	0.9
Steam	310	100	1188	40	-
Feed water to desuperheater and boiler	287	-	257	40	-
140 PSIG					
DEAERATOR					
Make up	76	-	44	-	0.9
Steam	400	-	1210	140	-
Feed water to desuperheater and boiler	362	-	334	140	-
Turbine Condenser	100	-	68	-	2.0

TABLE A-4 - PRESSURE REDUCING VALVE (PRV) AND DESUPERHEATER CHARACTERISTICS

PRESSURE REDUCING VALVES

PRV	Pressure IN psig	Pressure Out psig	Enthalpy Btu/LB
600/40	600	40	1351
600/140	600	140	1351
1250/600	1250	600	1460

DESUPERHEATER

Pressure psig	Enthalpy Out Btu/LB
40	1188
140	1210
600	1351

TABLE A-5 - FIXED STEAM LOADS

	Temp °F	Flow 10^3 LB/HR	Enthalpy Btu/LB	Pressure psig
200 psig process	435	10	1228	235
40 psig process	317	260	1188	40
Mechanical Drive				
To	700	190	1351	600
From	400	190	1210	140

TABLE A-6 - 40 PSIG PROCESS STEAM DEMAND

METERED PROCESS STEAM

Month		Enthalpy Flow, 10^6 Btu	Weight Flow, 10^3 LB
Aug	1976	210792	
Sept			273821
Oct		266364	
Nov		197779	
Dec		N.A.	
Jan	1977	264529	
Feb			279617
Mar		217240	
Apr		238724	
May		209421	
June		208922	
July		208553	
Aug		202460	

TABLE A-7 - MONTHLY BOILER STEAM FLOW
(THERMAL UNITS DATA)

MONTHLY BOILER STEAM FLOW, 10^6 Btu

MONTH	ELECTRIC #1	ELECTRIC #2	HOG FUEL #11	RED LIQUOR #1	RED LIQUOR #2	FOSSIL FUEL #6	FOSSIL FUEL #7	FOSSIL FUEL #8	FOSSIL FUEL #9	BLACK LIQUOR #10
*Aug 75	47095	-	-	34550	47907	25015	31960	0	178932	392811
Sep	53385	-	-	43583	60914	38115	83743	101902	106130	416454
Oct	17319	-	-	49680	74235	65199	104002	37937	235753	479113
Nov	37512	-	-	41972	54376	33377	54758	152458	197619	381662
Dec	49781	-	-	35018	40022	50207	46470	126495	165980	297521
Jan 76	81593	47087	-	8654	8930	94319	113149	83834	118648	489303
Feb	59467	45044	74350	-	-	48411	109753	47380	0	423376
Mar	59632	53188	205553	8251	10825	47762	106409	54232	0	384179
Apr	66539	61189	394232	48957	65672	74828	135364	0	0	526514
May	52931	39243	260424	38300	49436	21399	55486	0	111204	369297
June	45477	31050	299127	37375	48330	6461	9130	18745	111193	334918
July	8688	46046	159830	27593	35981	25411	39244	38841	62123	193862

*Jan, Apr, July & Oct are 5 week months
All others are 4 week months

TABLE A-8 - MONTHLY BOILER STEAM FLOW
(WEIGHT UNITS DATA)

MONTHLY BOILER STEAM FLOW, 10^3 LB

MONTH	ELECTRIC #1	ELECTRIC #2	HOG FUEL #11	RED LIQUOR #1	RED LIQUOR #2	FOSSIL FUEL #6	FOSSIL FUEL #7	FOSSIL FUEL #8	FOSSIL FUEL #9	BLACK LIQUOR #10
*Aug 76	22670	30390	204350	29540	48890	11190	16740	0	103050	251790
Sep	8320	28890	206570	31980	49520	8230	0	24770	107730	264320
Oct	10620	51670	279180	37000	54100	27060	26340	50680	98570	301580
Nov	32830	36260	205140	20050	33380	0	6990	11610	103910	252360
Dec	25140	7790	146540	5210	7710*	0	13660	25200	91270	210740
Jan 77	35840	21040	235500	34740	44500	24840	62890	100830	105100	324100
Feb	25450	24490	238610	33810	39910	0	28170	46590	122710	301290
Mar	2130	15000	248700	36680	40180	0	13610	115940	136390	284560
Apr	3650	2010	299740	45650	45750	0	67140	125460	147860	348370
May	0	0	260440	347000	43710	0	53780	71630	12690	266290
June	0	0	259000	31320	43730	0	52190	24300	106700	264000
July	0	0	236630	29950	42480	20100	81470	64860	89060	276840
Aug	0	0	256380	31110	44780	45850	72020	75520	11420	274840

*Jan, Apr, July & Oct are 5 week months.
All others are 4 week months

TABLE A-9 - Sawmill Steam and Power Generation

Steam from (to) Sawmill Powerhouse - 10^6 Btu of 140 LB Steam	
1975 AUG.	158448
SEP.	154924
OCT.	213599
NOV.	145304
DEC.	115875
1976 JAN.	147701
FEB.	114347
MAR.	96024
APR.	121108
MAY	77329
JUNE	27709
JULY	8919
AUG.	(1332)
SEP.	(26957)
OCT.	(51065)
NOV.	14716
DEC.	(11991)

	10^6 Btu	10^3 LB	Net 10^6 Btu
1977 JAN.	(87490)	22390	(59500)
FEB.	(91920)	32960	(50700)
MAR.	(75510)	27630	(41000)
APR.	(68200)	37900	(20800)
MAY	(80000 est)	37790	(32800)
JUNE	(93550)	46380	(35500)
JULY	(52800)	37790	(5600)
AUG.	(49300)	36380	(3800)

Power Generated MWH	
1975 AUG.	0
SEP.	0
OCT.	0
NOV.	0
DEC.	0
1976 JAN.	0
FEB.	0
MAR.	0
APR.	1613
MAY	1690
JUNE	800
JULY	0
AUG.	0
SEP.	0
OCT.	0
NOV.	0
DEC.	0
1977 JAN.	0
FEB.	0
MAR.	0
APR.	29797
MAY	26166
JUNE	23506
JULY	19305
AUG.	22981

TABLE A-10 - 1980 ENERGY REQUIREMENTS
CHANGES FROM FEBRUARY 1977

Plant Modification	Steam Demand Change 10^3 LB/HR
Veneer dryer	7
New lathe	5
Refuse burner	3
Retire #3 sawmill	-16
Veneer dryer	12
Retire old veneer dryer	-15
R-W Alt B	-25
#3 Machine speedup	21
#5 Machine speedup	9
#4 Machine expansion	24
Cl_2 Plant	8
#1 Pulp down	-62
TOTAL	-29

TABLE A-11

MILL DATA, SELECTED DAYS

Days	Number of Batch Cooks, Kraft	Number of Batch Cooks, Sulfite	Total Mill Production ADT/D, Board Machines, Pulp Machine, R & W Machines	No. 3 Batch Bleach Plant BBDT/Day
June 24, 1977	74	20	1142	225
June 25, 1977	70	21	1126	265
June 29, 1977	68	20	1014	280
July 21, 1977	77	20	1023	235
YTD Ave, 9/77	65	18	1123	270

TABLE A-12

600 Psig Process Load Changes
(Soot Blowing Only)

Basis - - Schedule from Longview Power Plant Operators

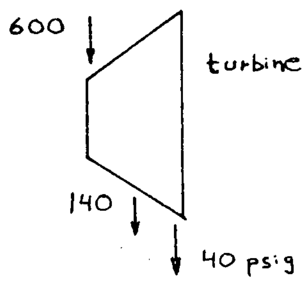
Assume two fossil boilers requiring soot blowing - - Total 15 minutes

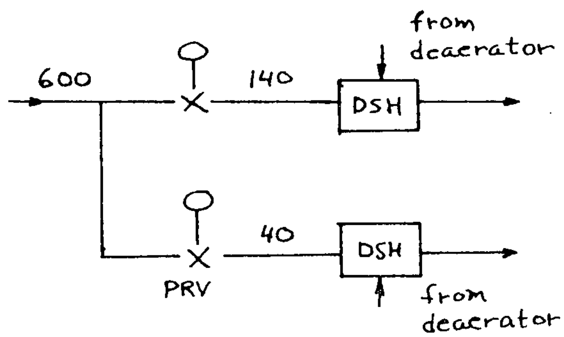
TIME	DEMAND, M#/HR	BOILER(S)
7:00 a.m.	15	10
8:00 a.m.	30	10 & 11
8:28	15	10
9:00 a.m.	30	10, 1 & 2
9:10	15	10
10:00	30	10, Fossil
10:15	15	10
12:00 p.m.	45	10,11, 1 & 2
12:25	30	10,11
12:28	15	10
3:00	30	10, 1 & 2
3:10	15	10
4:00	30	10 & 11
4:28	15	10
6:00 p.m.	45	10,Fossil, 1&2
6:15	30	10, 1 & 2
6:25	15	10
8:00	30	10 & 11
8:28	15	10
9:00	30	10, 1 & 2
9:10	15	10
12:00 M	45	10, 11, 1 & 2
12:25 a.m.	30	10 & 11
12:28	15	10

TIME	DEMAND, M#/HR	BOILER(S)
2:00 a.m.	30	10, Fossil
2:15	15	10
3:00	30	10, 1 & 2
3:10	15	10
4:00 a.m.	30	10 & 11
4:28	15	10
6:00 a.m.	30	10, 1 & 2
6:25	15	10

A.3 STEAM REQUIREMENTS FOR POWER GENERATION

It is possible to determine the additional steam required to generate power by looking at process energy loads and the requirement that they be the same with or without power generation. This is equivalent to saying that the energy/mass flow after the turbines must equal that after the PRV's/desuperheaters.





or $$\dot{m}_{140_t} h_{140_t} = X \dot{m}_{600} h_{600} + \dot{m}_{de_{140}} h_{de_{140}}$$

& $$\dot{m}_{40_t} h_{40_t} = (1-X) \dot{m}_{600} h_{600} + \dot{m}_{de_{40}} h_{de_{40}}$$

where X = fraction of 600 lbs. thru 140 PRV

or adding -

$$\dot{m}_{140_t} h_{140_t} + \dot{m}_{40_t} h_{40_t} = \dot{m}_{600} h_{600} + \dot{m}_{de_{140}} h_{de_{140}} + \dot{m}_{de_{40}} h_{de_{40}}$$

The same deaerator, the 40 psig deaerator, is used to supply the 40 and 140 psig desuperheater flow, with $h_{de_{40}} = h_{de_{140}}$ giving

$$\dot{m}_{de} = \dot{m}_{de_{140}} + \dot{m}_{de_{40}}$$

& $$h_{de} = h_{de_{40}} = h_{de_{140}}$$

This results in

$$\dot{m}_{140_t} h_{140_t} + \dot{m}_{40_t} h_{40_t} = \dot{m}_{600} h_{600} + \dot{m}_{de} h_{de_{40}}$$

Now, $$\dot{m}_{140_t} + \dot{m}_{40_t} = \dot{m}_{140} + \dot{m}_{40} + \dot{m}_{de}$$

or $$\dot{m}_{600_t} = \dot{m}_{600} + \dot{m}_{de}$$

or dividing thru the equation above

$$\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t} = \frac{\dot{m}_{600} h_{600} + \dot{m}_{de} h_{de_{40}}}{\dot{m}_{600} + \dot{m}_{de}}$$

or $$\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140_t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40_t} = \frac{h_{600} + \frac{\dot{m}_{de}}{\dot{m}_{600}} h_{de_{40}}}{1 + \frac{\dot{m}_{de}}{\dot{m}_{600}}}$$

Solving for $\frac{\dot{m}_{de}}{\dot{m}_{600}}$

$$\left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t}\right) + \frac{\dot{m}_{de}}{\dot{m}_{600}}\left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t}\right)$$

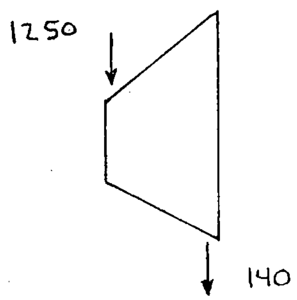
$$= h_{600} + \frac{\dot{m}_{de}}{\dot{m}_{600}} h_{de_{40}}$$

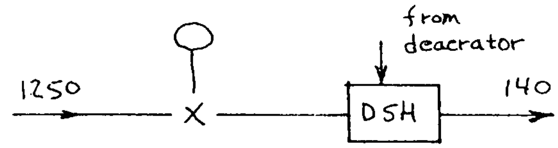
or $$\frac{\dot{m}_{de}}{\dot{m}_{600}}\left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t} - h_{de_{40}}\right)$$

$$= h_{600} - \left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t}\right)$$

or $$\frac{\dot{m}_{de}}{\dot{m}_{600}} = \frac{h_{600} - \left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} h_{140_t} + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} h_{40t}\right)}{\frac{\dot{m}_{140t}}{\dot{m}_{600_t}} h_{140_t} + \frac{\dot{m}_{40t}}{\dot{m}_{600_t}} h_{40_t} - h_{de_{40}}} \qquad (A)$$

A similar exercise can be done with the 1250 psig system





For the 1250 system, the deaerator is the 140 psig one.

The resulting equation is

$$\frac{\dot{m}_{de\,140}}{\dot{m}_{1250}} = \frac{h_{1250} - h_{140t}}{h_{140t} - h_{de\,140}}$$

These values for deaerator flow over boiler flow are a function of the turbine efficiency and, for the 600 psig system, the ratio of 40 and 140 bleeds.

For the turbines, the theoretical steam rates (SR) are

Pressures	SR					
600 → 140	24.2	LB/KW Hr.	for	h_{600}	=	1351
600 → 40	15.2	"	"	"		"
1250 → 140	14.7	"	for	h_{1250}	=	1460

or, if efficiency is accounted for

$$\Delta h_{turbine} = \eta \frac{3412}{SR}$$

or

$$h_{\substack{turbine\\bleed}} = h_{inlet} - \Delta h_{turbine}$$

$$= h_{inlet} - \eta \frac{3412}{SR}$$

For these studies, an efficiency of 0.62 was used for the 600 psig turbines and 0.72 for the 1250 psig turbine

or for the <u>600 psig</u>

$$h_{40_t} = 1351 - 0.62\left(\frac{3412}{15.2}\right)$$
$$= 1212$$

&

$$h_{140_t} = 1351 - 0.62\left(\frac{3412}{24.2}\right)$$
$$= 1264$$

for the <u>1250 psig</u>

$$h_{140_t} = 1460 - 0.72\left(\frac{3412}{14.7}\right)$$
$$= 1293$$

The 40 psig deaerator has an enthalpy of

$$h_{de_{40}} = 257$$

The 140 psig deaerater has an enthalpy of

$$h_{de_{140}} = 334$$

Plugging all these in above equations

For the 600 psig system,

$$\frac{\dot{m}_{de}}{\dot{m}_{600}} = \frac{1351 - \left(\frac{\dot{m}_{140t}}{\dot{m}_{600t}} 1264 + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} 1212\right)}{\frac{\dot{m}_{140t}}{\dot{m}_{600t}} 1264 + \frac{\dot{m}_{40t}}{\dot{m}_{600t}} 1212 - 257}$$

If considered seperately,

$$\left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{40} = \frac{1351-1212}{1212-257} = 0.146 \qquad \left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{140} = \frac{1351-1264}{1264-257} = 0.086$$

For the 1250 psig system,

$$\frac{\dot{m}_{de}}{\dot{m}_{1250}} = \frac{1460-1293}{1293-334} = 0.174$$

The ratio for the 1250 psig system in 600 psig steam would be:

$$\left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{1250} = 0.174\left(\frac{1460}{1351}\right) = 0.188$$

Before a value can be obtained for the 600 lb. system, the ratio of 40 psig and 140 psig extractions must be known.

An average annual steam demand was used to determine the conditions and to calculate $\dot{m}_{de} / \dot{m}_{600}$

First, from Figure 2, the average steam demand is approximately 1,100,000 lbs./hr.

Fixed loads were assumed to be:

Mech. drive turbines	190,000
600 lbs. process	16,000
235 lbs. process	10,000
140 PRV	50,000
40 PRV	50,000
	316,000 LB/Hr.

The 40 lb. load was assumed to be 300,000 lbs/hr of which (300,000-50,000) equals 250,000 of 600 psig steam. To supply this thru a turbine, 1.146 x (250,000) = 287,000 would be required.

This leaves 1,100,000 - 316,000 - 250,000 or 534,000 of 140 lb. steam to be supplied by the turbine.

Initially this can be assumed to be split between the 600 and 1250 system -

or $$\left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{140} = \frac{.086 + .188}{2} = 0.137$$

or $$1.137\ (534000) = 607{,}000$$

giving a requirement of

$$\begin{array}{r} 607000 \\ 287000 \\ 316000 \\ \hline 1210000 \end{array}$$ of 600 psig steam

to generate power.

This new figure allows a new estimate of where 140 psig steam comes from.

The average baseload in 600 psig boiler steam is 1,300,000, or at the condition above, the hog fuel boiler would be 1,300,000-1,210,000 = 90,000 less than maximum or 505,000 in 600 psig steam or 470,000 in 1250 psig steam.

The hog fuel turbine supplies 505,000 and the 600 psig turbines supply the rest, or estimating the increase in the 600 psig steam due to the loss in deaerator flow for the 140 psig steam,

$$\left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{140} = .086\left(1 - \frac{505}{607}\right) + .188\left(\frac{505}{607}\right)$$

$$= 0.170$$

or $$1.170\,(534000) = 625000$$

is required to meet the 140 psig load

or the new steam rate is

625,000
287,000
316,000
1,228,000

This new estimate gives a

1,300,000 - 1,228,000 = 72,000 reduction of hog fuel capacity or 595,000 - 72,000 = 523,000 in 600 psig steam.

This means the hog fuel turbine supplies $\frac{523}{625}$ of 140 psig steam

or boiler output should be increased

$$\left.\frac{\dot{m}_{de}}{\dot{m}_{600}}\right|_{140} = .086\left(1 - \frac{523}{625}\right) + .188\left(\frac{523}{625}\right)$$

or $1.171\,(534000) = 625000$

or the same as above.

Or summarizing the data,

there is 523,000 of 600 psig steam (483,000 of 1250 lb. steam) thru the hog fuel turbine

625-523 = 102,000 of 600 psig steam thru the 140 psig discharge of the 600 psig turbine

287,000 of 600 psig steam thru the 40 psig discharge of 600 psig turbine

and a total of 287,000 + 102,000 = 389,000 thru the 600 psig turbine.

This would give the following electric power

$$\text{Power} = \frac{\text{Steam}}{\text{SR}} \times \eta$$

$$\text{or Hog fuel power} = \frac{483{,}000}{14.7}\,(.72) = 23.7 \text{ MW}$$

$$600/140 \text{ psig power} = \frac{102{,}000}{24.2}\,(.62) = 2.6 \text{ MW}$$

$$600/40 \text{ psig power} = \frac{287{,}000}{15.2}\,(.62) = 11.7$$

or total of 23.7 + 2.6 + 11.7 = 38 MW.

This data was used to calculate an average base value for $\dot{m}_{de}/\dot{m}_{co}$ to be used in calculating the maximum back pressure power of Fig. 2 using equation A.

Of the steam going thru the turbines, $\frac{523}{523+389} = 0.57$ goes thru the hog fuel 1250 psig turbine

or for an overall $\dot{m}_{de}/\dot{m}_{600}$ of

$$\frac{\dot{m}_{de}}{\dot{m}_{600}} = 0.188(.57) + 0.129(1-.57)$$

$$= 0.163$$

Once the new steaming rate has been calc ulated, the hog fuel boiler output and subsequent power can be determined. The steam generated by 600 psig boilers can then be calculated, assuming a fixed 40 lb. load, and the subsequent flows and power of the 600 psig turbines. Use of a constant value for $\dot{m}_{de}/\dot{m}_{600}$ causes some errors, but they are small.

A.4 STEAM SWING DATA

Steam swing data for each of the four selected days are tabulated in this section. The data show the level of swinging steam demand considered to be typical for all days, and a comparison of selected days' plant production data with annual averages.

JUNE 24 '77

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
7:00 a.m.	210	10:32 a.m.	270
7:05	200	10:35	201
7:12	240	10:36	190
7:23	160	10:40	220
7:25	205	10:45	140
7:30	170	10:53	190
7:33	245	11:00 a.m.	110
7:40	200	11:05	165
7:45	225	11:10	135
7:52	200	11:20	180
7:57	235	11:30	230
8:08 a.m.	150	11:40	250
8:10	232	11:45	285
		11:50	270
8:20	220	11:52	270
8:30	210	11:55	312
8:40	200	12:00 N	305
8:50	190	12:05	220
9:00 a.m.	180	12:07	255
9:10	170	12:10	220
9:15	160	12:11	270
9:25	155	12:15	215
9:28	200	12:22	175
9:31	165	12:27	225
9:33	210	12:40	145
9:35	190	12:47	235
9:41	190	12:52	185
9:46	185	12:57	220
9:48	290	12:59 p.m.	145
9:52	260	13:00	260
10:05 a.m.	155	13:08	220
10:10	205	13:14	175
10:20	230	13:15	215
10:30	248	13:22	130

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
13:40 p.m.	140	16:59 p.m.	235
13:45	190	17:02 p.m.	260
13:50	165	17:10	255
13:52	230	17:20	220
14:00 p.m.	175	17:30	200
14:10	295	17:40	180
14:22	225	17:50	160
14:23	265	18:02 p.m.	125
14:26	235	18:09	90
14:28	290	18:10	210
14:30	270	18:15	136
14:32	305	18:17	135
14:39	275	18:20	138
14:46	180	18:25	205
14:52	205	18:30	175
15:00 p.m.	180	18:31	205
15:03	225	18:36	140
15:10	190	18:44	190
15:14	235	18:49	140
15:20	146	18:52	165
15:21	140	18:58	145
15:22	200	18:59	190
15:31	165	19:01 p.m.	170
15:41	260	19:03	190
15:47	225	19:06	165
15:50	250	19:09	180
15:55	235	19:13	140
16:00 p.m.	260	19:15	180
16:13	270	19:23	120
16:23	215	19:27	140
16:30	320	19:30	125
16:36	290	19:38	225
16:43	310	19:43	205
16:45	312	19:45	235
16:50	255	19:57	90
16:54	280	20:00 p.m.	155

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
20:05 p.m.	165	23:00 p.m.	110
20:10	115	23:05	155
20:16	180	23:15	155
20:20	165	23:19	95
20:25	185	23:23	135
20:34	120	23:30	85
20:38	190	23:31	150
20:45	130	23:33	130
20:46	210	23:35	155
20:54	205	23:40	140
21:00 p.m.	135	23:42	185
21:04	195	23:45	150
21:10	120	23:47	140
21:15	215	24:00 p.m.	160
21:23	170	0:14	210
21:27	185	0.15	270
21:30	166	0.18	230
21:34	155	0.20	188
21:37	225	0.22	195
21:42	200	0.25	220
21:47	200	0.28	155
21:51	150	0.30	158
21:57	165	0.31	180
22:06 p.m.	165	0.43	130
22:14	115	0.45	200
22:19	170	0.50	150
22:26	165	0.55	205
22:30	125	1:00 a.m.	185
22:33	170	1:01	215
22:37	155	1.09	145
22:39	185	1:11	195
22:46	105	1:16	130
22:48	135	1:21	170
22:55	115	1:26	125
22:59	130	1:32	215

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
1:40 a.m.	140		
1:42	180		
1:46	145		
1:48	220		
1:59	150		
2:00 a.m.	170		
2:03	150		
2:04	185		
2:08	150		
2:10	170		
2:14	145		
2:15	225		
2:23	170		
2:25	205		
2:35	130		
2:47	140		
2:50	176		
2:55	235		
3:00 a.m.	205		
3:03	255		
3:24	190		
3:25	220		
3:30	175		
3:34	235		
3:44	245		
3:49	190		
3:52	225		
4:00 a.m.	170		
4:10	180		
4:20	190		
4:30	205		
4:31	105		
4:36	155		
4:44	95		
4:45	135		
4:50	105		
4:52	145		

JUNE 25, 1977

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
7:00 a.m.	160	10:52 a.m.	30
7:12	120	10:59	35
7:13	155	11:01 a.m.	15
7:20	140	11:07	45
7:24	140	11:20	5
7:30	105	11:25	85
7:35	165	11:30	110
7:44	95	11:35	100
7:49	160	11:38	125
7:55	85	11:59	40
7:58	130	12:02 p.m.	95
8:00 a.m.	115	12:09	45
8:03	145	12:15	125
8:09	110	12:18	145
8:13	130	12:22	130
8:22	80	12:27	190
8:30	81	12:33	125
8:31	90	12:39	140
8:39	15	12:46	145
8:45	30	12:50	130
8:53	85	13:08 p.m	135
8:59	45	13:16	85
9:01 a.m.	75	13:25	110
9:05	60	13:32	90
9:13	105	13:39	60
9:16	85	13.42	80
9:23	55	13:45	65
9:30	75	13:54	70
9:36	40	13:57	90
9:41	65	14:00 p.m.	100
9:52	15	14:05	93
10:01 a.m.	30	14:08	95
10:10	10	14:10	92
10:29	125	14:17	45

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
14:22 p.m.	50	16:30 p.m.	160
14:24	85	16:35	135
14:30	50	16:45	30
14:35	85	16:52	55
14:37	135	16:55	45
14:40	75	16:59	65
14:41	75	17:00 p.m.	38
14:43	115	17:05	25
14:45	125	17:07	65
14:48	110	17:15	20
14:50	120	17:25	85
14:54	120	17:29	50
14:57	155	17:30	90
15:01 p.m.	110	17:35	53
15:04	135	17:38	55
15:10	65	17:40	123
15:13	130	17:42	110
15:15	90	17:45	85
15:18	106	17:46	65
15:22	95	17:50	33
15:25	110	17:52	25
15:30	70	17:55	55
15:33	100	18:00 p.m.	5
15:35	70	18:02	60
15:40	108	18:05	40
15:43	50	18:08	10
15:45	70	18:10	8
15:50	105	18:16	30
15:55	70	18:25	115
15:59	95	18:30	148
16:03 p.m.	65	18:34	135
16:07	100	18:42	135
16:12	85	18:45	100
16:15	38	18:54	100
16:16	30	18:55	125
16:20	85	19:00 p.m.	125

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
19:04 p.m.	105	21:22 p.m.	165
19:13	105	21:27	135
19:15	80	21:32	175
19:18	110	21:38	125
19:20	33	21:40	135
19:21	20	21:49	135
19:28	50	21:50	126
19:32	50	21:55	155
19:35	114	21:59	140
19:36	110	22:02	160
19:37	46	22:04	145
19:40	80	22:05	138
19:44	45	22:11	155
19:45	70	22:15	154
19:50	80	22:25	100
19:52	100	22:28	145
19:55	75	22:34	140
19:58	95	22:45	75
20:03 p.m.	95	22:50	105
20:08	115	22:55	95
20:15	105	23:00 p.m.	140
20:16	130	23:05	130
20:26	85	23:10	100
20:30	110	23:15	90
20:35	23	23:21	150
20:36	15	23:30	85
20:37	70	23:32	105
20:40	105	23:40	110
20:43	90	23:42	100
20:45	120	23:45	50
20:50	120	23:49	115
20:53	190	23:52	100
20:57	165	23:53	130
21:06 p.m.	135	24:00 a.m.	77
21:12	160	0:02	70
21:16	125	0:05	85

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
0.10 a.m.	105	2:39 a.m.	170
0.15	179	2:43	145
0.17	195	2:47	145
0.25	204	2:50	50
0.26	200	2:52	90
0.30	163	2:59	90
0.33	165	3:03 a.m.	55
0.45	80	3:07	90
0.47	155	3:10	120
0.50	117	3:14	175
0.55	93	3:17	135
0.58	70	3:20	170
1:00 a.m.	155	3:24	150
1:08	105	3:25	180
1:15	145	3:31	100
1:20	115	3:32	155
1:24	160	3:35	89
1:29	145	3:45	35
1:30	91	3:50	171
1:35	173	3:54	200
1:37	115	3:55	146
1:40	135	3:59	130
1:48	95	4:01 a.m.	150
1:50	155	4:11	50
1:55	45	4:13	80
2:00 a.m.	110	4:23	85
2:05	70	4:32	120
2:08	115	4:44	75
2:14	130	4:52	95
2:20	95	4:53	80
2:22	125	4:54	110
2:25	90	4:59	95
2:28	115	5:00 a.m.	130
2:30	135	5:05	100
2:31	100		
2:35	113		

JUNE 29, 1977

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
7:00 a.m.	370	9:36 a.m.	210
7:05	340	9:39	200
7:10	330	9:40	220
7:14	330	9:46	250
7:18	310	9:58	195
7:29	310	10:01 a.m.	275
7:36	335	10:08	250
7:45	295	10:09	265
7:50	305	10:14	310
7:55	280	10:15	320
7:59	305	10:18	360
8:02 a.m.	275	10:25	240
8:08	235	10:28	285
8:10	270	10:32	260
8:16	245	10:35	295
8:22	270	10:40	307
8:30	290	10:44	300
8:37	260	10:46	320
8:43	310	10:50	290
8:52	275	10:55	330
8:58	305	10:58	350
9:05	255	11:07	280
9:14	220	11:10	320
9:15	240	11:11	335
9:16	235	11:19	300
9:19	210	11:20	355
9:21	215	11:24	335
9:23	210	11:25	325
9:24	175	11:28	410
9:26	180	11:30	365
9:31	140	11:33	325
9:32	150	11:39	370
9:33	235	11:45	300

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
12:05 p.m.	175	14:35 p.m.	405
12:09	300	14:44	350
12:14	290	14:55	335
12:15	360	15:01 p.m.	400
12:20	310	15:02	395
12:23	315	15:10	325
12:25	372	15:15	285
12:29	385	15:16	320
12:30	375	15:23	275
12:35	465	15:25	305
12:38	415	15:30	270
12:39	380	15:32	295
12:43	425	15:44	280
12:45	377	15:45	280
12:46	345	15:50	304
12:48	350	15:51	310
12:50	225	15:55	270
12:55	271	15:59	275
13:03 p.m.	200	16:00 p.m.	300
13:08	210	16:05	280
13:14	340	16:08	260
13:15	315	16:10	283
13:20	430	16:15	315
13:30	340	16:17	275
13:35	320	16:21	290
13:44	205	16:23	280
13:45	170	16:29	280
13:58	185	16:30	260
14:00 p.m.	380	16:33	300
14:01	415	16:40	245
14:05	390	16:44	255
14:09	455	16:46	270
14:15	395	16:50	285
14:24	345	16:55	250
14:26	370	17:00 p.m.	230
14:30	335	17:01	240

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
17:05 p.m.	225	19:32	165
17:10	205	19:35	216
17:13	230	19:36	220
17:14	205	19:39	200
17:15	200	19:44	225
17:16	225	19:50	220
17:17	240	19:55	255
17:23	180	20:00 p.m.	245
17:31	205	20:06	245
17:32	190	20:14	250
17:33	235	20:15	284
17:39	160	20:18	295
17:40	250	29:19	300
17:44	255	20:20	263
17:45	35	20:25	295
17:49	50	20:30	269
17:50	125	20:31	260
17:55	105	20:32	305
17:59	145	20:33	300
18:02 p.m.	190	20:39	190
18:05	155	20:40	220
18:08	175	20:44	200
18:10	210	20:45	210
18:16	185	20:47	215
18:20	210	20:50	184
18:25	210	20:51	190
18:30	200	20:55	200
18:45	210	20:59	175
18:52	210	21:00 p.m.	230
19:00	230	21:05	205
19:05	220	21:06	225
19:10	178	21:08	245
19:14	185	21:10	262
19:15	185	21:15	205
19:17	195	21:20	215
19:22	170	21:30	175
19:23	205	21:31	240
19:29	160	21:32	230

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
21:40 p.m.	225	23:50	195
21:45	250	24:00 a.m.	265
21:49	215	24:01	260
21:58	205	24:05	220
21:59	240	24:10	230
22:01 p.m.	265	24:15	240
22:05	250	24:23	240
22:09	210	24:25	215
22:14	200	24:31	215
22:17	215	24:34	230
22:20	220	24:44	250
22:28	255	24:45	245
22:32	210	24:52	205
22:43	240	24:55	240
22:45	250	24:59	250
22:47	285	1:02 a.m.	185
22:55	280	1:05	165
22:58	305	1:10	230
23:00 p.m.	265	1:15	155
23:05	250	1:16	180
23:08	285	1:18	175
23:10	265	1:20	205
23:15	270	1:23	215
23:19	245	1:30	195
23:20	270	1:35	235
23:24	255	1:40	225
23:25	270	1:46	205
23:28	260	1:47	220
23:30	190	1:50	205
23:32	205	1:52	220
23:35	223	1:59	185
23:38	200	2:00 a.m.	220
23:40	210	2:02	185
23:43	245	2:05	255
23:45	225	2:10	265
23:46	230	2:13	290

TIME	SWINGING STEAM FLOW, 10^3 LB/HR
2:15 a.m.	177
2:20	195
2:21	180
2:25	205
2:28	195
2:30	205
2:31	245
2:33	230
2:35	250
2:39	235
2:40	230
2:45	285
2:48	285
2:50	257
3:00 a.m.	215
3:03	230
3:05	215
3:10	230
3:14	215
3:15	215
3:17	215
3:23	220
3:30	265
3:32	245
3:35	270
3:36	245
3:43	265
3:44	270
3:49	250
3:50	345
3:55	370
4:15 a.m.	235
4:17	230
4:22	215
4:25	47
4:31	- 30

TIME	SWINGING STEAM FLOW, 10^3 LB/HR
4:32 a.m.	- 85
4:33	- 90
4:35	118
4:38	160
4:40	305
4:45	275
4:47	340
4:50	280
4:53	320
5:00 a.m.	280

JULY 21, 1977

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
7:00 a.m.	300	11:25	445
7:05	360	11:35	320
7:30	365	11:40	405
7:50	365	11:50	240
7:55	335	12:10 p.m.	270
8:05	335	12:15	290
8:10	335	12:20	280
8:20	335	12:25	320
8:25	305	12:32	300
8:35	345	12:40	380
8:40	345	12:45	288
8:45	315	12:47	260
8:55	345	12:50	275
9:15	345	13:00 p.m.	185
9:25	370	13:10	270
9:35	355	13:15	385
9:40	375	13:25	310
9:45	345	13:30	365
10:00 a.m.	355	13:38	365
10:05	335	13:40	410
10:15	375	13:50	410
10:17	355	13:55	365
10:20	395	14:00 p.m.	430
10:25	360	14:10	325
10:30	430	14:12	360
10:40	465	14:15	340
10:52	405	14:20	405
10:55	455	14:27	340
11:05 a.m.	390	14:30	360
11:10	405	14:38	300
11:15	340	14:40	305
11:18	435	14:45	320
11:20	365	14:47	425

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
14:48 a.m.	415	18:50	440
14:53	350	18:59	425
14:55	400	19:03 p.m.	430
14:58	395	19:10	365
15:00 p.m.	360	19:17	400
15:05	300	19:20	410
15:20	305	19:25	440
15:25	390	19:33	310
15:35	355	19:38	340
15:37	395	19:45	315
15:55	295	19:55	405
16:00 p.m.	350	20:10 p.m.	295
16:04	320	20:15	436
16:07	400	20:18	430
16:14	425	20:20	435
16:25	285	20:40	410
16:30	315	20:43	435
16:40	295	20:45	440
16:45	300	20:53	290
16:48	305	20:55	410
16:53	300	21:00 p.m.	295
16:59	425	21:03	340
17:00 p.m.	430	21:05	345
17:10	295	21:08	415
17:14	325	21:09	410
17:24	320	21:10	340
17:29	365	21:15	375
17:32	335	21:18	375
18:00 p.m.	410	21:20	360
18:10	295	21:23	380
18:13	305	21:28	380
18:15	315	21:30	345
18:20	285	21:38	460
18:26	330	21:45	430
18:38	365	21:52	440
18:45	315	21:53	430

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
21:58	385	1:03 a.m.	420
22:00 p.m.	385	1:05	400
22:15	360	1:14	285
22:17	380	1:15	330
22:18	380	1:17	305
22:20	268	1:23	300
22:30	210	1:30	255
22:32	270	1:34	275
22:37	210	1:40	265
22:38	165	1:43	280
22:39	225	1:50	265
22:43	250	2:00 a.m.	285
22:49	355	2:25	250
22:50	350	2:30	280
23:00 p.m.	330	2:33	295
23:05	245	2:40	285
23:15	235	2:44	330
23:20	240	2:45	335
23:23	275	2:48	300
23:28	240	2:50	305
23:30	220	3:00 a.m.	265
23:44	195	3:03	315
23:45	230	3:05	305
24:00 a.m.	175	3:08	335
0:05	240	3:24	220
0:15	115	3:29	230
0:18	170	3:30	255
0:24	170	3:35	290
0:25	246	3:43	250
0:29	370	3:48	270
0:33	335	3:50	320
0.38	375	3:55	290
0.45	320	4:03 a.m.	300
0.53	400	4:05	260
0.59	385	4:10	255

TIME	SWINGING STEAM FLOW, 10^3 LB/HR	TIME	SWINGING STEAM FLOW, 10^3 LB/HR
4:13 a.m.	275		
4:20	245		
4:25	255		
4:30	230		
4:40	270		
4:44	290		
4:45	305		
4:52	295		
4:55	300		
4:59	325		
5:00 a.m.	320		
5:01	310		
5:05	350		

APPENDIX B - INDUSTRY SURVEY DATA

B-1 API Mill Listing

The 117 mills identified by the API as burning bark or hogged fuels are listed in Table B-1. As discussed in Section 2.3, the list is arranged in decreasing order of quarterly variation in the amount of hog fuel consumed, as measured by the ratio of highest to lowest quarterly hog fuel consumption in 1976.

The 55 mills contacted in the survey are indicated by asterisks.

B-2 Survey Results Summary

The potential for hog fuel substitution in each of the 14 mills identified in the survey as candidates for swing-smoothing is shown in Table B-2. The swinging demand indicates the amount of fossil fuel steam that must be generated to ensure capability for "downswings" of the magnitude indicated. The mills are not identified, in accordance with the agreement with API to respect proprietary information. As discussed in Section 2.3, they are uniformly distributed within the API mill listing.

B-3 Fossil Savings Potential

Table B-3 summarizes the basis for extrapolation of the survey results to estimate a near-term fossil fuel savings potential of 3.2×10^6 BBL/Yr.

TABLE B-1 MILLS BURNING BARK AND HOG FUELS (API)

*Kimberly-Clark	Koosa Pines, Alabama
*Southland Paper Mills	Lufkin, Texas
*Crown Zellerbach	Port Angeles, Washington
*Menasha Corp.	North Bend, Oregon
*International Paper	Moss Point, Mississippi
*International Paper	Panama City, Florida
*South Carolina Ind.	Florence, South Carolina
*Southland Paper Mills	Houston, Texas
*Crown Zellerbach	Lebanon, Oregon
*International Paper	Vicksburg, Mississippi
*St. Joe Paper	Port St. Joe, Florida
*St. Regis Paper	Sartell, Minnesota
*International Paper	Watchez, Mississippi
*Hoerner Waldorf	Missoula, Montana
Container Corp.	Brewton, Alabama
*Georgia Kraft	Macon, Georgia
Hammermill Paper	Erie, Pennsylvania
*St. Regis	Pensacola, Florida
*Union Camp	Savannah, Georgia
Federal Paper Board	Riegelwood, North Carolina
*Nekoosa Edwards Paper	Nekoosa, Wisconsin
*Packaging Corporation of America	Counce, Tennessee
Chesapeake Corp.	West Point, Virginia
International Paper	Jay, Maine
Continental Can	Hopewell, Virginia
Georgia Kraft	Mahrt, Alabama
Gulf States Paper	Demolis, Alabama
Owens - Ill.	Valdosta, Georgia
St. Regis Paper	Tacoma, Washington
Scott Paper	Mobile, Alabama
*Consolidated Papers	Wisconsin Rapids, Wisconsin
International Paper	Spring Hill, Louisiana
International Paper	Ticonderoga, New York
Georgia Pacific	Bellingham, Washington
International Paper	Bastrop, Louisiana
Scott Paper	Everett, Washington
Charmin Paper	Mehoopany, Pennsylvania
ITT Rayonier	Jesup, Georgia
Westvaco	Covington, Virginia
International Paper	Georgetown, South Carolina
Continental Can	Port Wentworth, Georgia
Owens Illinois	Orange, Texas
Owens Illinois	Old Town, Maine
International Paper	Camden, Arkansas
Union Camp	Franklin, Virginia
International Paper	Pine Bluff, Arkansas

TABLE B-1 MILLS BURNING BARK AND HOG FUELS (API) (Continued)

International Paper	Bastrop, Louisiana
International Paper	Mobile, Alabama
*GlatFelter	Spring Grove, Pennsylvania
*Brunswick Pulp & Paper	Brunswick, Georgia
*Champion International	Canton, North Carolina
*Champion International	Courtland, Alabama
*Champion International	Pasadena, Texas
*International Paper	Chisholm, Maine
*Longview Fibre	Longview, Washington
*Owens Illinois	Big Island, Virginia
*Eastex	Evadale, Texas
*Westvaco	Charleston, South Carolina
*Boise Cascade	International Falls, Minnesota
*St. Regis Paper	Pensacola, Florida
Scott Paper	Westbrook Cumberland Mills, Maine
*Georgia Pacific	Bellingham, Washington
St. Regis	Rhinelander, Wisconsin
*Union Camp	Montgomery, Alabama
*Weyerhaeuser	Valliant, Oklahoma
Owens Illinois	Tomahowk, Wisconsin
*Wes Cor	Hawesville, Kentucky
Boise Cascade	Rumforford, Maine
Crown Zellerbach Corp.	Camas, Washington
Flambeau Paper Co.	Park Falls, Wisconsin
Georgia Pacific Corp.	Cjory, Indiana
Boise Southern	DeRidder, Louisiana
Boise Cascade	Steilacoom, Washington
Mosinee Paper	Mosinee, Wisconsin
Weyerhaeuser Company	Cosmopolis, Washington
Georgia Pacific	Crosset, Arkansas
American Can	Naheola, Alabama
Crown Zellerbach Corp.	Bogalusa, Louisiana
Great Southern	Cedar Springs, Georgia
Bowaters	Calhoun, Tennessee
Crown Zellerbach Corp.	West Linn, Oregon
Kimberly-Clark	Munising, Michigan
Georgia Pacific Corp.	Port Hudson, Louisiana
International Paper Co.	Bastrop, Louisiana
ITT Rayonier	Grays Harbor, Washington
Scott Paper	Oconto Falls, Wisconsin
Abitibi	Roaring River, North Carolina
Great Northern	Millinocket, Maine
Scott Paper	Muskegon, Michigan
International Paper Co.	Gardiner, Oregon
Potlatch	Cloquet, Minnesota
Weyerhaeuser	New Bern, North Carolina

TABLE B-1 MILLS BURNING BARK AND HOG FUELS (API) (Continued)

Hudson Pulp & Paper	Palatka, Florida
*Nekoosa Edwards	Port Edwards, Wisconsin
*Wausau Paper Mills	Brokaw, Wisconsin
*Hoerner-Waldorf	Roanoke Rapids, North Carolina
*Georgia Pacific	Crosset, Arkansas
Abitibi	Alpena, Michigan
Consolidated Papers	Wise Rapids, Wisconsin
*Buckeye Cellulose	Perry, Florida
*Abitibi Southern	Augusta, Georgia
*Container Corporation	Fernandina Beach, Florida
*Crown Simpson	Eureka, California
*Green Bay Packaging	Morrilton, Arkansas
*St. Regis	Jacksonville, Florida
*Continental Can	Hodge, Louisiana
*Crown Zellerbach	Port Townsend, Washington
Hoerner-Waldorf	St. Paul, Minnesota
*Weyerhaeuser	Longview, Washington
*Weyerhaeuser	Rothschild, Wisconsin
*Fibreboard	Antioch, California
*Georgia Pacific	Toledo, Oregon
*International Paper Co.	Texarkana, Texas
*Scott Paper	Winslow, Maine

TABLE B-2 SURVEY RESULTS SUMMARY

CANDIDATE MILL NO.		SWINGING DEMAND $\pm 10^3 \frac{LB}{HR}$
1		50
2		75
3		50
4		45
5		25
6		60
7		50
8		60
9		100
10		60
11		30
12		40
13		100
14		120
	Average	60

TABLE B-3 FOSSIL SAVINGS POTENTIAL

Total mills burning hog fuel and bark reporting to the American Paper Institute	117
Number of mills contacted	55
Number of mills in the base/swing situation:	
12 months/yr	6
6 months/yr	4
Equivalent number of mills in the base/swing situation for 12 months/yr	8
Number of mills moving into the base/swing situation	6
Average swinging demand reported, 10^3 lb/hr	60

Annual steam savings potential across all 117 mills, within five years, at 93% operating efficiency, 10^6 lb/yr

$$60 \times \frac{\frac{10^3 \text{LB}}{\text{HR}}}{\text{Mill}} \times 8760 \frac{\text{HR}}{\text{YR}} \times .93 \times 117 \text{ mills} \times \frac{14 \text{ mills}}{55 \text{ mills}} = 14{,}600 \times 10^6 \frac{\text{LB}}{\text{YR}}$$

Annual fossil consumption reduction, equivalent

10^6 BBLS $\frac{\text{oil}}{\text{YR}}$, at 1100 $\frac{\text{BTU}}{\text{LB}}$STM and 80% BLR.EFF.

$$14{,}600 \times 10^6 \frac{\text{LB}}{\text{YR}} \times 1100 \frac{\text{BTU}}{\text{LB}} \times \frac{1}{.80} \times \frac{1 \text{ BBL}}{6.3 \times 10^6 \text{BTU}} = 3.2 \times 10^6 \frac{\text{BBLS}}{\text{YR}}$$

APPENDIX C ENERGY RESOURCE IMPACT

(Prepared by Stanford Research Institute)

C-1 INTEGRATED PULP AND PAPER MILLS

The pulp and paper industry in the United States includes approximately 350 companies operating 750 plants. It is the fifth largest manufacturing industry and the fifth largest energy consumer among these manufacturing industries. Structural definition of this industry is difficult because many companies have large forestry holdings; many are substantially engaged in converting pulp and paper to the wide range of consumer products; some make only paper and some sell only pulp. Integrated pulp and paper mills produce at least their own wood pulp requirements.

Three basic processes are used by these plants to convert wood to pulp. These are mechanical, chemical, and "chemimechanical." The first method is the traditional procedure and the most simple. Mechanical pulping (groundwood) reduces the entire log to fibers by grinding against a stone cylinder. Yields run as high as 96 to 98 percent. Wood fibers are mingled with extraneous material to produce low-cost, short-service, and throwaway papers such as newsprint. In this mechanical pulping, the energy requirement is affected by the grinding characteristics of the wood. For example, the energy consumption per ton of pulp is 20 percent or more in the case of pine than for spruce of comparable quality, although both are softwoods.

In the second conversion process, fiber separation is accomplished by chemical treatment of wood chips to dissolve the lignin that cements the fibers together. Power requirements are less when chipping softwoods than when chipping hardwoods. There are two major chemical processes (sulfate pulping and sulfite pulping), which differ in chemical treatment and produce different pulps. The makeup chemical for sulfate pulping is essentially sodium sulfate. Sulfate pulping (also referred to as the Kraft or alkaline process) produces pulp of high physical strength and bulk but poor sheet formation. The process has a recovery system that not only recycles the pulping chemicals but also is a source of about one-half of the process energy. The yield of pulp is about 45 percent. The pulps are used for wrapping paper, linerboard, container board, printing and bond papers.

Sulfite pulping uses sulfurous acid and an alkali to produce pulps of lower physical strength and bulk, but has better sheet formation properties. The yield on the basis of the chipped wood is again about 45 percent. The pulps are blended with groundwood for newsprint and are used in printing and bond papers and tissue. This system was originally designed without a recovery system (similar to the older soda process that is still used in some plants), but as a result of environmental pressures, recovery processes have been developed.

The third pulp conversion process combines mechanical and various chemical processes for defibration, the most important of which is neutral sulfite semi-chemical, known as NSSC. A wide range of pulps is produced. The principal use has been in the manufacture of corrugated medium. The lignin content is too high for most other applications. Yields are in the range of 70 to 85 percent. The chemical and semi-chemical processes require large amounts of steam, and this steam is often used first to generate electricity.

The contribution of these processes to total U.S. production is in the following proportions:

	Percent*
Groundwood	10
Kraft	68
Sulfite	5
NSSC	8
All other	9

The study of the potential shift of power generation from gas and oil to hog fuel and coal was limited to analysis of integrated pulp and paper mills even though the basic compilations of wood processing plants (Posts and Lockwoods Directories) include many other plants that can and do use some or all of their wood waste as hog fuel. The pulp and paper mills were selected for the TES application because the pulp digesters draw upon the plant steam supply at very high rates at irregular intervals. As a consequence, gas-and-oil fired boilers are ordinarily used because of their correspondingly high demand response rates. Hog fuel or coal burned in grate-type boilers can only be used for that part of the plant steam generation that does not require such response rates.

The data derived from the Directories is believed to be representative of the U.S. pulp and paper mills, but there are some voids. Data from one large pulp and paper company are not available.

*Source: John G. Strange, The Paper Industry (1977)

Within these limits, the selected characteristics of the U.S. pulp and paper mills are summarized in Table C-1. The data are summarized for the five regions most frequently used by the wood industry and as a national aggregate. The regions are delineated in Figure C-1.

There are a number of trends significant to this research study that are not evident in Table C-1.

1. The industry growth is limited almost entirely to expansions of the existing mills. Therefore, the power generation will likely grow incrementally until sufficient boiler capacity reaches replacement time to justify its collective removal and replacement with a single boiler with greater capacity than the total of the removed units. This trend is evident in the current practice of installing larger and larger boilers in the mills. Until the fuel shortage and higher gas and oil prices, the trend was to remove or shut down the smaller hog fuel boilers that could not meet particulate emission requirements and replace these with gas- or oil-fired systems. This trend has been effectively stopped by the federal legislative efforts to force industry to obtain solid fuel boilers. Steam system suppliers are responding to this need by engineering new systems that can burn wood waste or coal alone or together. The power generation shift in this study has been limited to those mills that now use hog fuel, with the general assumption that the capacity of existing boilers will be modestly expanded and/or used to a greater extent with the addition of TES.

   At least one solid fuel system in advanced development, the fluidized bed,

TABLE C-1 A SELECTED CHARACTERISTICS OF U.S. PULP AND PAPER MILLS PRODUCTION CAPACITY, AND FUEL CONSUMERS BY TYPE.

	Total U.S.	Northeast	South Atlantic	North Central	South Central	Western
Number of mills that report consumption by fuel type	190	33	39	35	64	19
Production Capacity of Mills (tons per day (tpd))	126,209	14,603	39,411	10,693	49,057	12,445
(tons per hour (tph))	5,259	608	1,642	446	2,044	519
Average Capacity per mill (tph)	664	443	1,011	306	767	655
(tph)	28	18	42	13	32	27
Number of users, by fuel type						
Total	190	33	39	35	64	19
Gas	121	3	15	29	61	13
Oil	140	29	36	23	40	12
Coal	39	7	9	15	7	1
Hog fuel	90	10	28	8	35	9
Proportion of users consuming fuel (percent)						
Gas	64	9	38	83	95	68
Oil	74	88	92	66	63	68
Coal	21	21	23	43	11	63
Hog fuel	47	30	72	23	55	47

Source: Derived from Posts 1978 Pulp and Paper Directory

TABLE C-1 B SELECTED CHARACTERISTICS OF U.S. PULP AND PAPER MILLS

STEAM GENERATED IN PULP AND PAPER MILLS

	Total U.S.	Northeast	South Atlantic	North Central	South Central	Western
Major product line		Fine Papers	Linerboard	Printing/ Business	Container-board	Newsprint/ Pulp
Number of mills with steam boiler capacity that are included in the survey	179	31	38	31	61	18
Production capacity of the above mills (tph)	5,057	563	1,584	386	1,993	531
Number of mills with electric power generation equipment	117	25	33	15	36	8
Number of mills with unused power generation equipment	9	2	2	1	3	1
Production capacity of mills that generated electric power (117 mills) (tph)	3,811	431	1,482	219	1,378	301
Total hourly steam boiler capacity for 179 mills. (thousand lbs./hour)	120,185	15,185	40,450	8.703	44,435	11,920
Total hourly steam generation from 179 mills (thousand lbs./hour)	107,186	12,265	36,139	8,102	39,667	10,013
Total installed electric power capability, (117 mills) (Megawatts)	3,861	749	1,401	248	1,300	133
Total hourly electric power generation from 108 mills. (nine mills did not generate) (thousand kwh)	2,647	532	899	175	955	64
Number of boilers in 179 mills	578	93	128	88	198	71
Unit sizes of boilers:						
Under 200 thousand lbs./hour (percent)	58	75	34	85	49	68
200-399 " " "	26	14	36	13	29	30
400-599 " " "	9	7	16	1	12	2
600 thousand lbs./hour and over	7	4	14	1	10	-
Total	100	100	100	100	100	100

TABLE C-1 B SELECTED CHARACTERISTICS OF U.S. PULP AND PAPAER MILLS

STEAM GENERATED IN PULP AND PAPER MILLS (CONTINUED)

Operating pressure based on 65 mills that reported psig.							
Under 200 psig	(percent)	18	20	15	25	18	
200-599	"	20	10	15	42	18	-
600 psig and over	"	62	70	70	33	64	100
Total	"	100	100	100	100	100	100
Average capacity and production from steam generation and electric power equipment.							
Average hourly production capacity per mill. (179 mills)	(tph)	28	18	42	12	33	30
Average hourly steam boiler capacity per mill. (179 mills)	(thousand lbs./hour)	674	490	1,064	281	728	662
Average hourly steam generation per mill, (179 mills)	(thousand lbs./hour)	599	428	951	261	650	556
Average installed electric power capability per mill (117 mills)	(megawatts)	33	30	42	17	36	17
Average hourly electric power generation per mill (108 mills)	(thousand kwh)	25	23	29	13	29	9
Conversion at 10,500 Btu/kwh	(million Btu)	263	242	305	137	305	95
Average steam generated per tph production capacity (179 mills)	(thousand lbs./hour/ton)	21	24	23	21	20	19
Average hourly electric power generation per tph production capacity (108 mills)	(kwh/ton)	695	1,234	607	799	693	213
Converstion at 10,500 Btu/kwh	(million Btu)	7.3	13.0	6.4	8.4	7.3	2.2

Source: Derived from Posts 1978 Pulp and Paper Directory

TABLE C-1 C SELECTED CHARACTERISTICS OF U.S. PULP AND PAPER MILLS

ELECTRIC POWER USE IN PULP AND PAPER MILLS.

	Total U.S.	Northeast Region	South Atlantic	North Central	South Central	Western Region
Number of mills included in the analysis.	189	33	39	35	64	19
Mills with power generation equipment (percent)	62	76	79	47	59	42
Mills with unused capactiy (percent)	5	9	3	3	6	5
Installed Power Generation Capactiy.						
Number of units	348	66	119	45	97	21
Number of mills with power generation capacity	118	25	31	16	38	8
Number of mills generating power	108	22	30	15	34	7
Installed Capacity (thous. KW)	3752.2	628.1	1369.4	253.4	1368.5	132.8
Average capacity per mills (thous. KW)	31.8	25.1	44.2	15.8	36.0	16.6
Average capacity per unit (thous. KW)	10.8	9.5	11.5	5.6	14.1	6.3
Unit sizes of capacity (percent)						
Under 10 Megawatts (MW)	58	74	53	74	40	80
11 MW to 20 MW	29	10	34	26	41	10
20 MW to 30 MW	10	16	11	-	13	5
31 MW and over	3	-	2	-	6	5
Total	100	100	100	100	100	100
Total Hourly power generation (thousand kilowatt hours)	2636.9	527.4	869.6	175.1	1000.5	64.3
Hourly generation per mill (thousand kilowatt hours)	24.4	24.0	29.0	11.7	29.4	9.2

TABLE C-1 C SELECTED CHARACTERISTICS OF U.S. PULP AND PAPER MILLS

ELECTRIC POWER USE IN PULP AND PAPER MILLS. (CONTINUED)

Average capacity per mills (thous. KW)	31.8	25.1	44.2	15.8	36.0	16.6
Average capactiy per unit (thous. KW)	10.8	9.5	11.5	5.6	14.1	6.3
Unit sizes of capacity (percent						
Under 10 Megawatts (MW)	58	74	53	74	40	80
11 MW to 20 MW	29	10	34	26	41	10
21 MW to 30 MW	10	16	11	-	13	5
31 MW and over	3	-	2	-	6	5
Total	100	100	100	100	100	100
Total Hourly power generation (thousand kilowatt hours)	2636.9	527.4	869.6	175.1	1000.5	64.3
Hourly generation per mill (thousand kwh)	24.4	24.0	29.0	11.7	29.4	9.2
Percent of power use generated	57.4	60.5	74.5	38.7	59.1	15.7
Purchased Power.						
Number of mills buying power	139	23	28	25	51	12
Total purchased power (thous. kwh)	1957.2	343.7	297.6	277.6	693.6	344.7
Purchased power per user (thousand kwh)	14.1	14.9	10.6	11.1	13.6	28.7
Total Power Consumption (thousand kwh)	4594	871	1167	453	1694	409
Hourly power used per ton of capacity (kwh)	974	1,433	711	1,015	829[1]/	788[2]/

Source: Derived from Posts 1978 Pulp Paper Directory.

1/ Includes Tennessee Valley Authority territory.

2/ Includes Bonneville Power Administration territory.

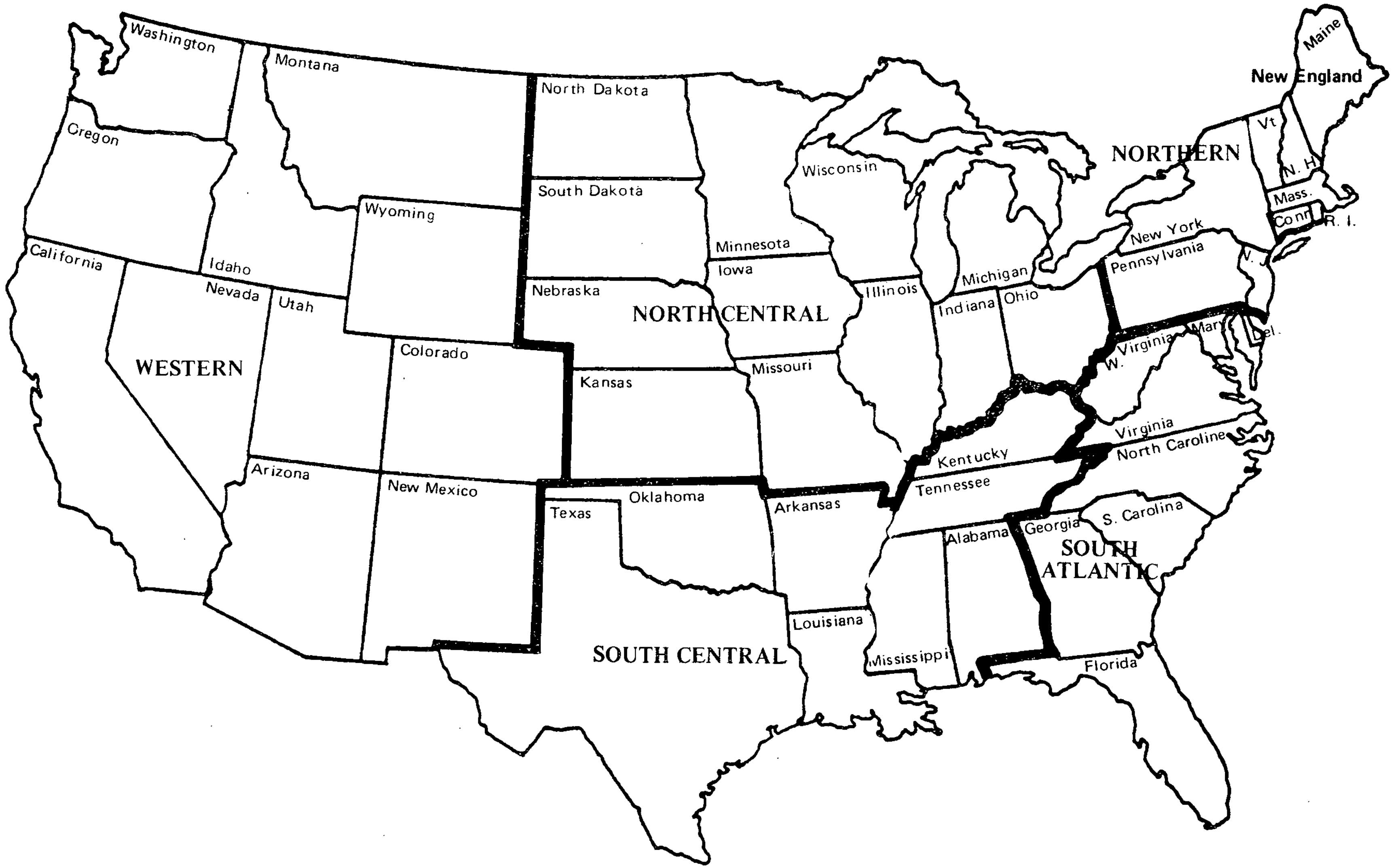


Figure C-1. The Five Wood Industry Regions offers promise of response times that would allow the solid fuel system to follow rapid steam demands. However, the near-term (early 1980's) applicability of the fluidized bed solid fuel system is doubtful.

3. The pulp and paper mills are increasing their utilization of the tree. The most favored current method is whole tree pulping. About 100 whole tree pulping machines are now in service in U.S. forests. This practice will reduce the amount of mill residues available for use as hog fuel and will force hog fuel users to obtain wood waste from other sources such as saw mills or by gathering from the forest floor. Additional discussion of the trend will be found in the subsequent section, LOGGING AND MILLING RESIDUES, dealing with the general hog fuel availability problem.

4. Milling residues are being upgraded. This trend toward better use of wood wastes in consumer products such as particleboard, mulching bark, charcoal briquettes, and pressed logs is logical and will continue. This study attempts to acknowledge and compensate for this competitive use of wood waste by valuing the hog fuel at an incremental price of $25 per bone dry ton. This is equivalent to $1.40 per million BTU and at economic parity with coal, so the economic assessments are applicable when hog fuel and coal are interchanged.

C-2 LOGGING AND MILLING RESIDUES

Wood residues of interest in this study include those resulting from the logging operations and those resulting from the milling operations. The logging residues include limbs, saplings, tree tops, cull trees, and slash. Milling residues include material such as slabs, cores, edgings, chips, shavings, and sawdust. Bark may be found in either category, depending upon where it is removed from the tree trunk.

As recently as 1972, some milling residues were regarded as a disposal problem, but the increased utilization of the tree and its parts has created substantial markets for such residues. Clean chips, fibers, and even some sawdust can be pulped; markets have been developed for particleboard and hardboard; wood flour is used in composition flooring, glues and plastics; briquettes, fireplace logs, mulch and soil amendments consume significant quantities of residues; and some is used in agricultural products such as livestock feed and poultry litter. Wood chips are also exported to Japan from the West Coast and to Sweden from Louisiana. It is apparent, then, that the use of milling residues as a fuel in the pulp and paper mills is only one of a number of competing uses for this material and that its use at any given time will be affected by the strength of external factors such as the housing market, consumer discretionary spending, and export demand.

Table C-2 summarizes the characteristics of the pulp and paper mills whose hog fuel consumption was given in the directories. Forty-seven percent of

TABLE C-2

CAPACITY AND HOURLY FUEL AND STEAM CONSUMPTION OF QUANTITATIVE HOG FUEL CONSUMERS.

	Total U.S.	Northeast	South Atlantic	North Central	South Central	Western
Number of mills that report hog fuel consumption	90	10	28	8	35	9
Number of quantitative users	60	7	22	7	18	6
Number of mills where hog fuel consumption exceeds 25 tons per hour (tph)	17	2	9	-	5	1
Production capacity of quantitative hog fuel consumers (tph)	59,568	5,213	25,250	2,550	22,125	4,430
(tph)	2,482	217	1,052	106	922	185
Total hog fuel consumption (tph) (60 mills)	1,203	154	530	43	395	81
(million Btu/hour)	21,661	2,771	9,539	777	7,107	1,467
Total of all fuel consumed by quantitative hog fuel users. (60 mills) (Energy equivalent million Btu)						
Gas	9,823	84	382	326	8,498	533
Oil	20,071	2,540	12,444	147	4,239	701
Coal	3,335	-	1,606	614	1,115	-
Hog fuel	21,661	2,771	9,539	777	7,107	1,467
Total	54,890	5,395	23,971	1,864	20,959	2,701
Proportion of above fuel use (percent)						
Gas	17.9	1.6	1.6	17.5	40.6	19.7
Oil	36.6	47.1	51.9	7.9	20.2	26.0
Coal	6.1	-	6.7	32.9	5.3	-
Hog fuel	39.4	51.3	39.8	41.7	33.9	54.3
Total	100.0	100.0	100.0	100.0	100.0	100.0
Total hourly electric power used of mills with quantitative hog fuel use (60 mills) (thousand kwh)	2,239	226	840	94	934	145

TABLE C-2

CAPACITY AND HOURLY FUEL AND STEAM CONSUMPTION OF QUANTITATIVE HOG FUEL CONSUMERS. (CONTINUED

Total steam generated by mills with						
Gas	17.9	1.6	1.6	17.5	40.6	19.7
Oil	36.6	47.1	51.9	7.9	20.2	26.0
Coal	6.1	-	6.7	32.9	5.3	-
Hog fuel	39.4	51.3	39.8	41.7	33.9	54.3
Total	100.0	100.0	100.0	100.0	100.0	100.0
Total hourly electric power use of mills with quantitative hog fuel use (60 mills) (thousand (kwh)	2,239	226	840	94	934	145
Total steam generated by mills with quantitative hog fuel use (60 mills) (thousand lbs./hour)	60,268	4,650	25,783	2,820	23,771	3,244
<u>Average fuel use per consumer and per ton of capacity in mills that use hog fuel. (60 mills)</u>						
Average use of hog fuel per consumer						
(tph)	20	22	24	6	22	14
(million Btu/hour	360	396	432	108	396	252
Hourly production capacity of mills that use hog fuel (tph per mill)	41	31	48	15	51	31
Hourly hog fuel use per tph capacity (million Btu/ton)	9	13	10	7	8	8
Hourly fuel use per tph of capacity (million Btu/ton)	23	25	24	20	23	15
Hourly electric power use per tph capacity (kwh/ton)	902	1,041	798	887	1,013	784
Steam generated hourly per tph capacity (thousand lbs./ton/hour)	24	21	25	27	26	18

Source: Derived from Posts 1978 Pulp and Paper Directory

the integrated mills are reported as using some hog fuel, with the majority of these plants located in the South Central and South Atlantic areas. The ratios of hog fuel users to reported mills vary significantly on a regional basis in reflection of the availability of the fuel and the proper equipment in which to burn it.

Region	Percentage Using Some Hog Fuel
South Atlantic	72 %
South Central	55
West	47
Northeast	30
North Central	23
National	47

The variations in hog fuel and boiler availabilities are also significant as reflected in the relative importance of hog fuel compared with the coal, oil, and gas used to fuel pulp and paper mills in the five U.S. regions of interest.

Region	Hog Fuel/Total Fuel
South Atlantic	.359
Northeast	.264
South Central	.254
Western	.239
North Central	.110
National	.276

These ratios are used subsequently in estimates of the market penetration of TES systems. These ratios do not include consideration of the energy contribution of pulping liquor recovery systems that supply about one-half of the pulp and paper mill energy needs.

From the standpoint of availability and regional utilization trends, it would appear that some logging residues are available in the forests in all regions, but that the greatest quantities currently available are in the western region. The cost of removal may be high, but an additional value might be added to the material by reason of the benefits that accrue for aesthetic and environmental purposes. Recent action taken on national forests to improve timber use includes modification of timber sale contracts to provide such greater incentives for removal of low-value material.

SRI used the data base developed for the National Science Foundation* to prepare estimates of the additional amount of wood waste that might be used as hog fuel in the selected regions of the United States. These estimates were made in an effort to determine whether wood waste availability could hinder the market penetration of TES systems.

The most important source of the forestry data was the surveys of the primary wood processing industry prepared by the Regional Offices of the U.S. Forest Service. For 39 states, sufficient data were available to incorporate county-

*Crop, Forestry, and Manure Residue Inventory, Continental United States, SRI Project 5093, data base developed for The National Science Foundation (June 1976) by-county data. In the case of Illinois, Minnesota, North Carolina, Ohio, South Carolina, Virginia, and Wisconsin, sufficient data were available on a statewide basis. No data were available from Nevada or North Dakota. The estimates were prepared by identifying the resident county and the adjoining counties for each of the identified integrated pulp and paper mills. This arbitrary distance limit is reasonable in terms of transporting the waste to the mill. The inventories for these selected counties were then tabulated and summed by state in each of the five U.S. regions.

The basic data present the wood waste inventories as bark, logging residues, pulping bark, and milling residues. The summary data given in Table C-3 do not continue this distinction in the interest of brevity, since hog fuel can by any of these kinds of wood waste.

The category definitions for Table C-3 are:

- Sold--that portion of available residues that is collected and sold for any purpose other than fuel in the case of forestry residues. All forestry residues used as fuel are included as fuel regardless of source or previous sale.
- Fuel--that portion of available residues that is used as fuel without sale. This category includes all forestry residues used as fuel.
- Wasted-- that portion of the available residues that must be disposed of at an economic cost (i.e., hauled away or burned). This category includes all logging residues as well as collected residues that are not sold, fed, or used as fuel (i.e., they are returned to the soil at an economic cost).

TABLE C-3 FORESTRY RESIDUES (ANNUAL DRY TONS)

STATE	SOLD	FUEL	WASTED	TOTAL
Maine	641,744	190,613	2,033,036	2,865,491
Massachusetts	26,315	12,841	92,697	131,850
New Hampshire	91,140	11,274	195,328	297,745
New Jersey	4,030	5,483	14,026	23,546
New York	244,741	147,027	265,222	657,037
Pennsylvania	355,036	152,182	1,493,507	2,000,728
Vermont	8,184	1,745	41,570	51,501
Total Northeast	1,371,190	521,245	4,135,386	6,027,904
Florida	546,613	822,737	754,620	2,124,003
Georgia	813,661	1,219,866	499,675	2,533,237
North Carolina	398,763	149,787	130,608	679,175
South Carolina	475,521	554,141	307,680	1,337,363
Virginia	581,738	360,467	188,569	1,130,794
West Virginia	566,849	239,651	813,551	1,620,052
Total South Atlantic	3,383,145	3,346,649	2,694,703	9,424,624
Illinois	1,603	1,068	2,674	5,350
Indiana	16,967	2,089	76,275	95,334
Iowa	1,780	1,186	2,967	5,933
Michigan	239,019	58,360	1,080,409	1,377,818
Minnesota	244,776	71,861	587,718	904,360
Missouri	10,978	13,393	47,674	72,050
Ohio	112,906	56,443	232,365	401,741
Wisconsin	330,763	183,209	253,319	767,314
Total North Central	985,792	387,609	2,283,401	3,629,900
Alabama	1,939,880	1,111,591	5,381,990	8,433,526
Arkansas	1,032,432	532,387	2,212,939	3,777,782
Kentucky	21,262	4,079	86,943	112,299
Louisiana	1,777,843	1,081,901	3,465,714	6,325,535
Mississippi	775,108	325,429	2,747,594	3,848,165
Oklahoma	249,973	109,967	380,642	740,590
Tennessee	63,717	125,725	545,607	735,082
Texas	1,032,975	174,579	2,335,169	3,542,724
Total South Central	6,893,190	3,465,658	17,156,598	27,515,703
Arizona	221,670	82,797	373,911	678,381
California	995,929	796,053	3,973,387	5,765,380
Idaho	885,268	270,778	695,119	1,851,177
Montana	579,810	182,138	453,625	1,215,581
Oregon	9,890,770	4,250,641	5,359,914	19,501,348
Washington	3,418,241	2,351,473	1,108,460	9,878,205
Total Western	15,991,688	7,933,875	14,964,416	38,890,072

Source: SRI International

When the data are aggregated by regions and converted from annual tons to tons per hour for comparison with the potential increased usage, it can be concluded that wood waste availability is not a limiting factor for its anticipated increased use as hog fuel with the introduction of TES systems. The comparison is given in Table C-4.

TABLE C-4 FOREST RESIDUE AVAILABILITY AND INCREASED HOG FUEL USAGE
(TONS PER HOUR)

REGION	INCREASED USAGE	AVAILABLE *
Northeast	36	472
South Atlantic	256	308
North Central	8	261
South Central	221	1,959
Western	93	1,708
National	612	4,708

*Residues now identified as wasted

Source: SRI International

C-3 FOSSIL FUEL AND ELECTRICITY PRICES AND AVAILABILITY

The economics of this TES application in the pulp and paper mills are significantly affected by the prices to be paid for the fossil fuels and the purchased electricity that are to be displaced by increased hog fuel use and the incremental cogeneration likely to accompany this use.

In 1977, the pulp and paper industry was paying less than three cents per kilowatt-hour as an energy charge for its purchased electricity. Some hydroelectric power in the northwest was said to be purchased for 0.1 cent per kilowatt-hour following the heavy winter rains. Such abberations in the trend cannot be allowed to distract attention from the established trends for industrial electricity prices.

The current federal and state legislative efforts are clearly directed toward reversal of the previous rate structures that give the largest users of electricity the lowest unit prices. "Lifetime" rates, higher demand charges, time-of-day pricing, and similar rate actions are all directed to delivering the cheapest electricity to individual retail customers and the highest price electricity to the large industrial users. SRI has studied electricity price trends in great detail for a number of commercial and government clients, and projections from these studies are summarized in Table C-5.

The procedure for obtaining price estimates that are internally consistent and correspond to a plausible development of the U.S. energy system over time is based on the use of results of the SRI National Energy Model

TABLE C-5 U.S. INDUSTRIAL ELECTRICITY AND FUEL PRICE PROJECTIONS
(IN 1975 DOLLARS PER MILLION BTU)

ELECTRICITY	1975	1985	2000	2020
Northeast	5.6	7.6	9.4	10.5
South Atlantic	5.0	7.2	9.0	10.1
South Central	5.4	7.5	9.5	10.5
North Central	4.5	6.7	8.7	10.2
Western	6.1	7.5	8.8	10.1
National	5.3	7.3	9.3	10.3
GAS				
Northeast	1.2	3.6	4.4	4.6
South Atlantic	0.9	3.0	4.0	4.1
South Central	0.8	2.7	3.7	4.0
North Central	0.9	3.0	3.4	3.6
Western	0.8	2.6	3.0	3.8
National	0.9	2.8	3.6	4.0
OIL				
Northeast	2.3	2.9	3.6	4.1
South Atlantic	2.2	2.9	3.7	4.2
South Central	2.1	2.8	3.5	3.7
North Central	2.2	2.9	3.6	3.9
Western	2.2	2.8	3.5	3.9
National	2.2	2.9	3.6	4.0
COAL				
Northeast	1.1	1.5	1.7	1.6
South Atlantic	1.2	1.5	1.6	1.6
South Central	1.2	1.3	1.4	1.5
North Central	0.9	1.1	1.2	1.3
Western	1.1	1.4	1.4	1.4
National	1.1	1.3	1.4	1.4

calculations and independent estimates of the variation of the quantities over time. The steps that were followed in devising this base case scenario are:

1. An energy demand projection was selected that is consistent with estimates that governmental and private analyses have produced and is plausible considering:

   - Past energy growth rates and recent downward trends in the growth rates resulting from a combination of higher energy prices, government policies that encourage conservation, and an increasing public awareness of cost effective energy conservation methods.
   - Saturation of energy demands for certain end uses over the longer term.

2. The energy demand estimates and results of SRI's National Energy Model calculations that were recently performed for EPRI were used to estimate the supply of different energy types (i.e., oil, gas, coal, nuclear fuel) that must be produced to meet the demand.

3. The estimated market clearing prices were noted for the different energy types that are consistent with the assumptions of the model and the levels of energy supply and demand over time. Based on independent estimates of energy prices over time*, the price estimates and quantities of energy supply were revised to more nearly approach consensus estimates of changes of energy prices over time.

*Sources for energy price projections include the Edison Electric Institute, Bureau of Mines, Bureau of Labor Statistics, and the Monthly Energy Review.

4. Steps 1 through 3 were repeated, testing for consistency between supply, demand, and price estimates. These tests included testing against SRI judgment such factors as growth rates in production of specific energy forms, penetration of new technologies, rates of transition over time from one type of fuel to another, etc.

5. The energy price estimates obtained in Step 4 were disaggregated to the regions of interest in this study using, as a basis for this disaggregation, the regional variations in these quantities estimated in model runs.

The major increase in oil prices has already occurred and SRI projects the prices for this fuel to increase at a moderate rate, as can be seen in Table C-5. Gas prices will be deregulated and will reach oil prices on a BTU basis. Coal prices will remain competitively lower because of the high costs for using this fuel in an environmentally acceptable manner. The availability of each of these fuels and electricity will be significantly altered by federal and state regulations. Industrial users of gas and electricity can generally expect to be interrupted whenever there is a temporary dislocation or shortage that requires a choice between residential and commercial users or the industrial customers. The federal efforts to mandate solid fuel boilers for new and replacement industrial installations will have some success. Load management programs that regularly interrupt industrial use of electricity during peak hours are forthcoming. Rate structure modification to force industrial cogeneration is being attempted by the California Public Utility Commission.

The sum of these actions is that the pulp and paper industry will be under very strong economic and regulatory pressure to increase its use of hog fuel and coal.

C-4 PRESENT ENERGY USE IN THE MILLS

The data compiled from the directories are sufficient to establish representative energy use patterns for the mills in the five different regions. The regional variations can be attributed to factors such as mill size, mill products, regional availability and price of fuels and electricity, pulping processes and wood species. The selected data are summarized in Table C-6.

There are a number of trends that are not apparent in the tabulated data. Those of significance to increased hog fuel and coal use are discussed here. The pulp and paper mills have a history of cogeneration and are unique, or one of a few, in their acceptance of power generation as an integral part of their production process instead of an ancillary operation. This is quite likely due to the fact that about one-half their energy requirements have been met by the wood residues carried in the pulping liquors. The chemicals contained in the pulping liquors must be recovered to obtain satisfactory process economics and to meet water quality requirements for plant discharges. The special steam generating furnaces and boilers are therefore integral to the whole pulping process, and their energy contributions is directly proportional to the plant production rate. The energy use patterns in Table C-6 do not include this part of the pulp mill's energy. The trend toward improved yields

TABLE C-6 U.S. PULP AND PAPER MILLS

HOURLY PRODUCTION CAPACITY AND FUEL CONSUMPTION

	Total U.S.	Northeast	South Atlantic	North Central	South Central	Western
Major product line		Fine Paper	Linerboard	Printing/ Business	Container-board	Newsprint Pulp
Number of mills reporting quantitative fuel use	123	22	26	24	38	13
Production capacity of mills (tons per day (tpd))	86,933	9,518	29,840	7,885	30.675	9,015
(tons per hour (tph))	3,623	397	1,243	329	1,278	376
Fuel consumption of quantitative users. (123 mills) (Physical quantities)						
Gas (thousand Mcf)	18,374.1	84.3	475.5	1,117.2	13,477.1	3,219.9
Oil (thousand gallons)	220.3	41.4	108.6	18.7	41.0	10.5
Coal (thousand tons)	0.332	0.075	0.070	0.113	0.073	-
Hog fuel (thousand tons)	1.203	0.154	0.530	0.043	0.395	0.08
(Energy equivalent Million Btu)						
Gas	18,374.0	84.3	475.5	1,117.2	13,447.1	3,219.9
Oil	30,397.6	5,718.7	14,982.1	2,581.2	5,660.7	1,454.9
Coal	7,782.3	1,930.7	1,605.7	2,578.6	1,667.3	-
Hog fuel	21,659.4	2,770.2	9,538.2	777.6	7,106.4	1,567.0
Total	78,213.3	10,503.9	26,601.5	7,054.6	27,911.5	6,141.8
Porportion of fuel use by type (percent)						
Gas	23.5	0.8	1.8	15.8	48.3	52.4
Oil	38.9	54.4	56.3	36.6	20.3	23.7
Coal	10.0	18.4	6.0	36.6	6.0	-
Hog fuel	27.6	26.4	35.9	11.0	25.4	23.9
Total	100.0	100.0	100.0	100.0	100.0	100.0
Number of reporting steam generators	123	22	27	23	37	14
Hourly steam generated by quantitative fuel users. (thousand lbs./hour	86,385	10,210	20,953	1,113	31,600	7,208
Average production and fuel consumption. (123 mills)						
Average capacity per mill (tpd)	707	433	1,196	39	897	693
(tph)	29	18	48	14	34	29

TABLE C-6 U.S. PULP AND PAPER MILLS

HOURLY PRODUCTION CAPACITY AND FUEL CONSUMPTION (CONTINUED)

Average hourly fuel use per mill (million Btu)	636	477	1,023	294	735	472
Average fuel use per tph capacity (million Btu/ton)	21.6	26.5	21.4	21.4	21.8	16.3
Number of consumers						
Gas	75	1	8	16	40	10
Oil	83	21	25	12	18	7
Coal	24	5	3	12	4	-
Hog fuel	60	7	22	7	18	6
Average hourly fuel use per consumer: (physical quantities)						
Gas (75 mills) (Mcf)	244,987	84,333	59,689	69,826	336,928	321,988
Oil (83 mills (gallons)	2,655	1,974	4,345	1,559	2,279	1,506
Coal (24 mills) (tons)	13.8	15.1	23.4	9.4	18.3	-
Hog fule (60 mills) (tons)	20.1	22.0	24.1	6.2	21.9	13.6
Energy equivalent (million Btu)						
Gas (75 mills)	245.0	84.3	59.7	69.8	36.9	322.0
Oil (83 mills)	366.1	272.3	599.3	215.1	314.5	207.8
Coal (24 mills)	324.3	386.1	535.2	214.9	416.8	-
Hog fuel	361.1	395.7	433.5	111.2	394.8	244.5
Steam generated hourly yper tph capacity (thousand lbs./ton/hour)	24	26	25	19	25	19

Source: Derived from Posts 1978 Pulp and Paper Directory

in the pulping process is slow, but it will steadily reduce the amount of wood residue in the pulping liquors and the energy contribution of this source.

A number of the smaller south central mills were constructed when industrial electricity and natural gas prices were unrealistically low. The trend for this period was to save plant investment by purchasing the entire electrical requirements and by using gas-fired boilers for the steam at pressures near the 150 psig used for charging the digesters--a pressure too low for cogeneration. Hog fuel and coal were in disfavor for these new plants. This trend has been stopped, but the plant layout for these plants may make real siting problems for the installation of newsolid fuel storage and preparation facilities, if not for the boiler and TES systems themselves.

The north central mills generally did not have access to low-cost electricity and gas, so the trend in that region was toward maximum use of hog fuel. When the wood waste was being upgraded beyond hog fuel values, the north central mills increased their use of coal. That trend was temporarily altered by the emission requirements placed on industrial boilers, but increased fuel prices and previous regional dependence on hog fuel (including ample site space for fuel storage and preparation) can allow the assumption that this region will contain more likely candidates for new hog fuel boilers and TES systems than their southern counterparts.

The trend toward installation of larger and higher pressure boilers (600 to 1200 psig) is logically accompanied by the installation of back pressure turbines for cogeneration, since the operating pressures for the digester are not usually more than 150 psig.

C-5 TES-INDUCED CHANGES IN ENERGY USE

The industry survey conducted by Weyerhaeuser (see section 2.3) yielded quantitative estimates of the amount of steam that could be shifted to solid fuel generation if TES systems were satisfactorily installed in the identified candidate plants. SRI combined those estimates with the total steam generation reported for those same plants in the Directories. The data are presented in Table C-7 and the average shift of 10.1 percent is rounded to 10 percent for this study. This 10 percent shift is then assumed for all the present hog fuel users.

It is conservatively assumed that only those mills now using hog fuel would be likely to increase their usage in this manner. Valid arguments have been advanced that new boiler installations will generally be able to burn solid fuels, but a basis for quantitative estimates of this group was not established in this study, so these mills are not included in the extrapolations.

The stated reasons for the mixed use of hog fuel and coal included the limited availability of hog fuel and its occasionally high moisture content. No basis for changing the regional ratios of hog fuel to coal use were found, so these ratios were held constant for the extrapolations. The credible price of $25 per ton of hog fuel maintains its economic parity with coal, so the economic analyses would not be changed significantly by changes in these ratios. The air quality impact could be affected by any changes in these ratios when sulfur dioxide emissions are of concern, since the coal is the source of this

TABLE C-7 POTENTIAL SHIFT OF STEAM GENERATION WITH A TES SYSTEM
(THOUSANDS OF POUNDS OF STEAM PER HOUR)

PLANT	STEAMING RATE	SHIFT WITH TES
1	123	30
2	170	25
3	205	40
4	275	20
5	500	50
6	600	45
7	750	100
8	1090	110
9	1200	75
	4915	495

Average Shift = 10.1%

sulfur dioxide. Particulates would not be changed by variations in these ratios, since the particulate emission limits are identical for coal and hog fuel.

The pulp and paper mills are generally acknowledged as exemplary in their use of cogeneration to obtain a significant portion of their required electricity. The actual split between cogenerated and direct-fired electricity generation in the mills was not determinable from the data reported in the Directories. The credit for incremental cogeneration is credible on the basis of industrial electricity price projections and on the basis of the higher pressure boilers that are finding increasing application in the mills. The amount cogenerated is based on the following general assumptions:

- Electrical conversion efficiency--76 percent
- Net power/generated power--0.95
- Pounds of steam/kilowatt-hour--36
- BTU/kWh of purchased electricity--10,500

When gas or oil can be displaced, the gas is preferentially removed because of the increasing restrictions on industrial gas use. Any balance is then removed from the oil use.

The estimated national shifts in fuel use are summarized in Table C-8 and restated graphically in Figures C-2 and C-3.

C-6 MARKET PENETRATION RATES

The resource impact estimates reflect implementation of the 10 percent shift

TABLE C-8 ENERGY RESOURCES IMPACT OF A 10% SHIFT OF STEAM GENERATION TO SOLID FUELS AND THROUGH COGENERATING TURBINES - 214 U.S. INTEGRATED PULP AND PAPER MILLS

		HOURLY ENERGY USE			
Energy Source		1977	2000	Increased	Decrease
Pulping liquids - MMBtu		68430	68430	-0-	-0-
Hog Fuel	MMBtu	36451	47510	11059	
Bone-Dry tons		2027	2639	612	
Coal	MMBtu	12974	15621	2647	
Short tons		553	667	114	
Oil	MMBtu	50155	46623		3532
Thousand barrels		8.65	8.04		0.61
Natural Gas	MMBtu	33971	28389		5582
Thousands cubic feet		33971	28389		5582
Purchased electricity-MMBtu		23895	20162		3733
Megawatt hours		2276	1920		356

Annual Fossil Fuel Savings at the Mills

$\underset{\text{Gas}}{(5582} + \underset{\text{Oil}}{3532)}$ x 8760 Hours/Yr = 79,838,640 MMBtu

Annual Fossil Fuel Savings at the Electric Utilities

356 MWH x 10.5 MMBtu/MWH x 8760 Hrs/Yr = 32,744,880 MMBtu

Total (10% Shift + Cogeneration = 112,583,520 MMBtu

Oil Equivalent = 17.87 MMBL

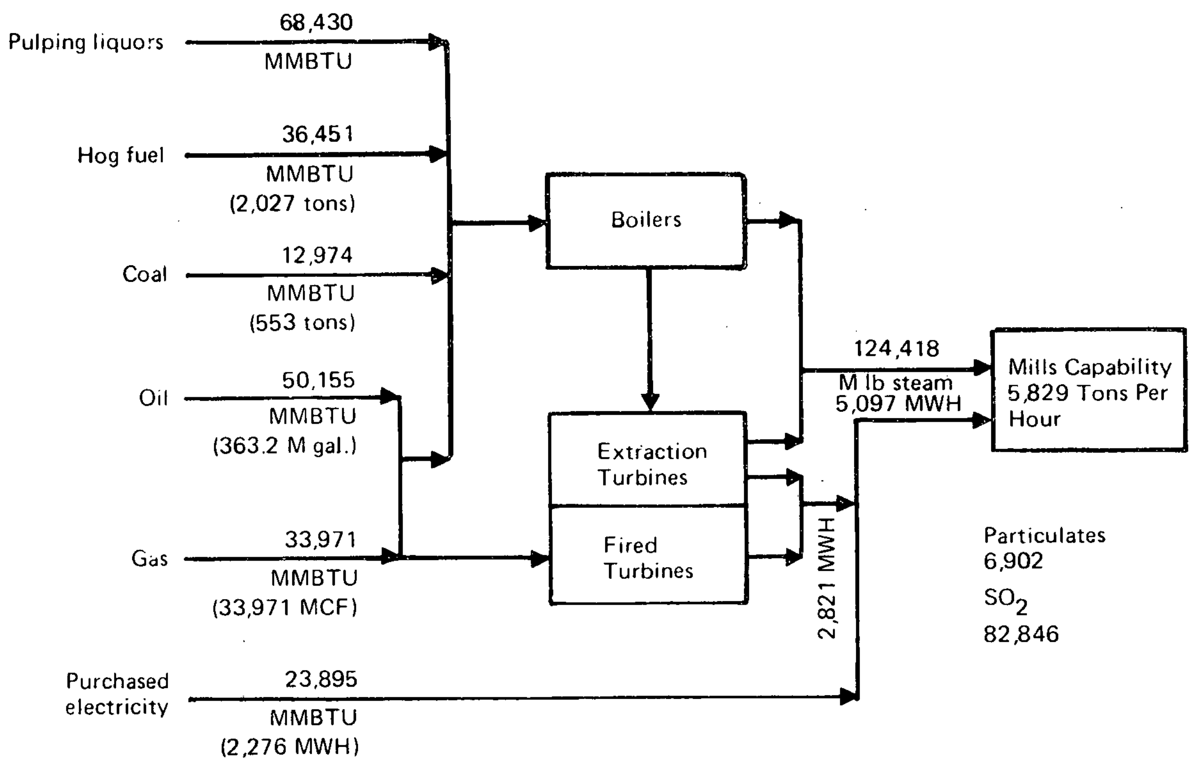


Figure C-2. Hourly Energy Use For: 214 U.S. Integrated Mills

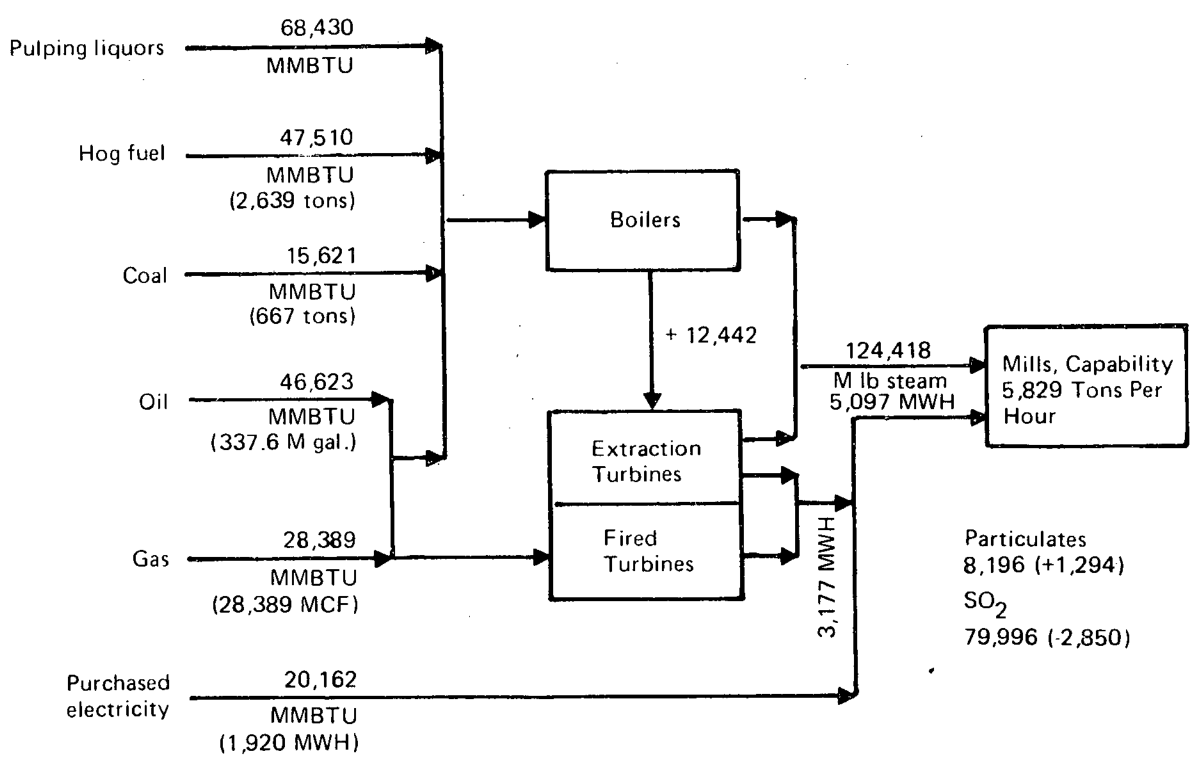


Figure C-3. Hourly Energy Use For: 214 U.S. Integrated Mills with 10% Shift of Steam Generation To Solid Fuels and Through Cogenerating Turbines in steam generation and its incremental cogeneration in all of the present mills that use hog fuel. This could readily occur by the year 2000.

The first step in market penetration could begin in 1981 and be complete by about 1985. This would consist of TES installation in the 14 plants identified as having a positive interest during the Weyco survey .

The second step of market penetration would be one-quarter of all present hog fuel users, corresponding to the ratio of interested-to-interviewed in the Weyco survey. This step would be achievable from 1985 to 1990.

The third step of market pentration would be the remaining three-quarters of the identified hog fuel users. This step would be achievable from 1990 to 2000.

C-7 ATMOSPHERIC EMISSION CHANGES

A shift of a portion of the pulp and paper mills' steam generation from gas and oil to solid fuel is expected to increase the emissions of particulates. Any increased use of coal increases the emissions of sulfur dioxide as well. Since natural gas combustion does not result in emissions of either of these pollutant species, the displacement of gas does not improve the overall emissions impact. The displacement of fuel oil will yield a reduction of the sulfur dioxide that is associated with the combustion of this fuel.

Since industry in general will be under increasing pressure to reduce its use of natural gas for raising steam, SRI considers it most credible to first displace natural gas from the fuel mix of the pulp and paper mills as they increase their use of solid fuels. The atmospheric emission estimates that follow are, therefore, in that sense, conservative, since some individual mills might continue to use gas and reduce their oil usage instead. Such a decision will depend upon local fuel availability and price beyond the detail level of this study.

The atmospheric emission estimates are also conservative in that they are based on the direct extrapolation of coal use in its present ratio to hog fuel in those regions where both solid fuels are currently used in the selected mills. The individual decisions regarding increased use of coal will include factors such as the relative values of hog fuel and coal, f.o.b. the mill, and the incremental cost of achieving the allowable sulfur dioxide emission levels with coal. If coal users are finally forced to use both low-sulfur coal and to remove SO_2 from the stack gas--a distinct possibility under one EPA interpretation of the best available control technology (BACT) requirement of the Clean Air Act--then coal use will likely decrease and more hog fuel will be burned by the mills.

The emission estimates include the increases of particulate and sulfur dioxide at the pulp and paper mills and the decreases of these two species at the utilities that are the likely suppliers of the supplemental electricity purchased by the mills. The decreases at the utilities are proportional to the incremental electricity that is expected to be cogenerated when the mills have installed their TES system and are able to burn more hog fuel. There will be some beneficial increase in the dispersal of the atmospheric emissions from the central generating plant to the individual mill sites, depending upon local considerations. This dispersal benefit is not estimated in this study.

SRI prepared these estimates with a general underlying assumption that all the mills and utilities meet at least the U.S. emission standards for particulates and SO_2. State standards did not differ greatly from the national standards for those fuels and applications studied in the five U.S. regions, but such variations were used in the estimates wherever noted.

The national aggregates of particulate and SO_2 emissions, before and after introduction of a 10 percent shift to solid fuel and its associated incremental cogeneration, are presented in Table C-9. The net effect is a reduction of more than two pounds of SO_2 emissions for every additional pound of particulates. The health effects of particulates, especially those from hog fuel, have not been determined, but these particulates are considered by some to be aesthetically undesirable. The health effects of SO_2 are known to be deleterious and reduction in the emissions of this specie is definitely desirable.

The regional variations from the national picture are significant, and are therefore discussed separately in detail.

NORTHEASTERN STATES

Thirty-six mills in the Northeastern region of the country were analyzed.* In 1976 the mills in this region consumed a total of about 225 trillion BTU's of energy. Existing mills in this region rely heavily on their own fuel

*Includes two census regions: New England (6 states) and Middle Atlantic (3 states).

TABLE C-9 PARTICULATES AND SO_2 EMMISSIONS
214 U.S. MILLS
(POUNDS PER HOUR)

	BASE CASE		10% FUEL SHIFT and COGENERATION	
	PARTICULATES	SO_2	PARTICULATES	SO_2
AT MILL				
HOG FUEL	3,961	-0-	5,155	-0-
COAL	1,577	16,990	1,885	20,369
OIL	-0-	47,408	-0-	44,159
AT UTILITY				
COAL	1,364	14,560	1,156	12,282
OIL	-0-	3,888	-0-	3,186
TOTAL	6,902	82,846	8,196	79,996

	PARTICULATES	SO_2
DIFFERENCE	+1,294	-2,850

SOURCE: SRI INTERNATIONAL

supplies. Pulping liquors and hog fuel together account for 50 percent of heat requirements; oil provides another 35 to 36 percent, with coal and natural gas making up the difference. Coal that is burned is probably utilized only in the mills in New York and Pennsylvania. Very little natural gas is used; only about one-half percent of the mills total energy needs.

The mills in the Northeastern region purchase nearly 40 percent of their electricity requirements. Typical of the utilities supplying power to these mills are Central Maine Power, Niagara Mohawk, and Rochester Gas and Electric. Based on the operation of those three utilties for 1975 and 1976, it was determined that the average fuel mix for the then various generating plants approximated the following pattern:

Fuel Type	Share (%)
coal	62%
oil	38%

A brief review of the emission standards for the Northeastern states has been made, and the results of that work are summarized in Table C-10. Basically, it has been assumed that the emission standards or emission limits are applicable both to industrial facilities and to electric utility plants. Most states within this region have fairly strict emission limits. Thus, for purposes of this analysis, it does not make much difference which state is selected as being typical for all states within the region.

The net effect on emission of particulates and sulfur dioxides from mills in the northeastern states is presented in Table C-11. Emissions are shown both at the mills--as a result of burning the indicated fuel mix--and at the utilities --for generation of the mills' electricity purchases and based on the utilities

TABLE C-10

EMMISSION LIMITS FOR PARTICULATES AND SULFUR DIOXIDES

NORTHEASTERN STATES
(Pounds per Million Btu Input)

Particulates:

Maine:	For both old and new equipment of sizes greater than 100 million Btu per hour input, and all fuels: 0.3*
New York:	For both old and new equipment of sizes greater than 200 million Btu per hour input, and all fuels: 0.1

Assumed control of particulates emissions in all states at 0.1

Sulfur Dioxides:

Maine:	Control is based on sulfur in the fuels, but there is no regulation for fuel combustion. Sulfur limit for all fuels in Connecticut is 0.55 percent.
New York:	For equipment larger than 200 million Btu per hour input, and all fuels: 1.65. This limit in Pennsylvania is 1.8.≠

Assumed control for sulfur dioxides emissions in all states at 1.65

* Limit is 0.1 in Connecticut and Vermont.

≠ For the Pittsburg area, however, the limit is 0.6

Source: Developed by SRI International

TABLE C-11 PARTICULATES AND SO_2 EMISSIONS
36 NORTHEASTERN MILLS
(POUNDS PER HOUR)

	BASE		10% FUEL SHIFT and COGENERATION	
	PARTICULATES	SO_2	PARTICULATES	SO_2
<u>AT MILL</u>				
HOG FUEL	453	-0-	518	-0-
COAL	316	5,212	361	5,952
OIL	-0-	15,441	-0-	14,619
<u>AT UTILITY</u>				
COAL	244	4,027	215	3,554
OIL	-0-	2,468	-0-	2,178
TOTAL	1,013	27,148	1,094	26,303

	PARTICULATES	SO_2
DIFFERENCE	+81	-845

SOURCE: SRI INTERNATIONAL

estimated fuel mix discussed previously. For the base case, total particulate emissions are over 1,000 pounds per hour, and total SO_2 emissions over 27,000 pounds per hour.

For the case with a 10 percent shift in fuels utilized, and with increased self-generation of electricity at the mills, particulate emissions do not change significantly but overall SO_2 emissions decrease by 845 pounds per hour over the base.

South Atlantic States

Forty mills in the South Atlantic region of the country were analyzed. In 1976, the mills in this region consumed a total of about 540 trillion BTU's of energy. The mills in this region utilize a large quantity of self-generated fuels, both pulping liquors and hog fuel. These two energy sources account for 57 to 58 percent of total energy requirements. Oil provides 37 to 38 percent of energy requirements, coal about 4 percent, and gas the balance -- no more than 1 to 2 percent.

The mills in this region purchase about one-quarter of their electricity requirements. Typical of the utilities supplying power to the mills are Georgia Power and Florida Power. Based on the operation of those two utilities for 1975 and 1976, it was determined that the fuel mix for the two company's various generating plants approximated the following pattern:

Fuel Type	Share (5)
coal	40%
oil	40%
gas	20%

A brief review of the emission standards for the South Atlantic states has been conducted, and the results of that work are summarized in Table C-12 In general, it was assumed that the figures for emission limits are applicable both to industrial facilities and electric generating plants. Some states within this region do not have emission limits as strict as those for Florida and Georgia; however, for purposes of this analysis, the most rigid standards were selected as being appropriate for all states within the region.

Table C-13 presents data showing the net effect on emission of particulates and sulfur dioxides from mills in the South Atlantic states with a shift in type of fuel used. Data are presented both for the mills and for the utilities that supply electricity to the mills. With the current fuel use pattern--at the mills and at the utilities--total emissions amount to 1842 pounds per hour of particulates and nearly 24,000 pounds per hour of SO_2. For the case with a 10 percent shift in fuels used and increased self-generation of electricity at the mills, the reduction in SO_2 is about 10 percent.

North Central States

Forty-one mills in the North Central region of the country were analyzed.* In 1976, these mills consumed a total of about 157 trillion BTU's of energy. The mills in this region of the country rely on all fuels in roughly the same proportion. While self-generated fuels--pulping liquors and hog fuel--account for about 40 percent of total energy requirements, purchased fuels account for the balance--coal and oil each supply about 25 percent and gas the remainder.

*Includes two census regions: East North Central (5 states) and West North Central (7 states)

TABLE C-12

EMISSION LIMITS FOR PARTICULATES AND SULFUR DIOXIDES

SOUTH ATLANTIC STATES
(Pounds per Million Btu Input)

Particulates:

Florida:	For both old and new equipment of sized greater than 250 million Btu per hour input, and all fuel: 0.10
Georgia:	For existing, large-sized equipment and all fuels: 0.24; for new, large-sized equipment and all fuels: 0.10

Assumed control for particulates emissions in all states at 0.10

Sulfur Dioxides:

Flordia:	For new equipment of sizes greater than 250 million Btu per hour input, and maximum two-hour average: solid fuels - 1.2 and liquid fuels - 0.8.
Georgia:	For new equipment of sizes greater than 250 million Btu per hour input, but no time limit specified: solid fuels - 1.2 and liquid fuels - 0.8

Assumed control for sulfur dioxides emissions in all states as follows:

Solid fuels - 1.2
Liquid fuels - 0.8

Source: Developed by SRI International

TABLE C-13 PARTICULATES AND SO_2 EMISSIONS
40 SOUTH ATLANTIC MILLS
(POUNDS PER HOUR)

	BASE		10% FUEL SHIFT and COGENERATION	
	PARTICULATES	SO_2	PARTICULATES	SO_2
<u>AT MILL</u>				
HOG FUEL	1,467	-0-	1,929	-0-
COAL	247	2,964	325	3,898
OIL	-0-	18,439	-0-	16,012
<u>AT UTILITY</u>				
COAL	128	1,538	83	990
OIL	-0-	1,026	-0-	660
TOTAL	1,842	2,3967	2,337	21,560

	PARTICULATES	SO_2
DIFFERENCE	+495	-2407

SOURCE: SRI INTERNATIONAL

The mills in the North Central states purchase over 60 percent of their electricity requirements. Typical of the utilities supplying this power are Wisconsin Electric Power and Wisconsin Power and Light in Wisconsin, and Consumers Power in Michigan. Based on the operation of these utilities for 1975 and 1976, it was estimated that the fuel mix for the various generating facilities of all three utilities approximated the following pattern:

Fuel Type	Share (5)
coal	90%
oil	10%

A brief review of the emission standards for the North Central states has been made, and the results of that work are summarized in Table C-14. In general, as discussed previously for the two East Coast regions, it was assumed that the emission limits for particulates and SO_2 are applicable both to industrial plants and electric generating plants. Originally established limits for particulates ranged between 0.4 0.8 pounds per million BTU input in most states, but regulations in both Wisconsin and Illinois are more severe; 0.15 and 0.10 respectively. For SO_2 emissions, the limits are 1.2 pounds per million BTU input for coal and 0.8 for oil. These limits are roughly comparable to these two figures for the East North Central states, but are considerable higher in the West North Central states. As before, however, the most rigid standards were selected as being typical for all states within this region.

Table C-15 shows the net effect of shifting fuel use on emissions of particulates and sulfur dioxides from mills in the North Central states. Because of the fuel use configuration by both the mills and electric utilities in this region, there

TABLE C-14

EMISSION LIMITS FOR PARTICULATES AND SULFUR DIOXIDES

NORTH CENTRAL STATES
(Pounds per Million Btu Input)

Particulates:

Wisconsin:	For both new and old equipment, all sizes, and all fuels, the limit is 0.15
Michigan:	For both new and old equipment, all sizes, and all fuels, the limit is 0.18

Assumed control for particulates emissions in all states at 0.15

Sulfur Dioxides:

Wisconsin:	For both new and old equipment, all sizes, the limit for coal is 1.2, for oil 0.8
Michigan:	For both new and old equipment, all sizes, the limit is 1.0 for both coal and oil.

Assumed control for sulfur dioxides emissions in all states as follows:

Solid Fuels - 1.2
Liquid Fuels - 0.8

Source: Developed by SRI International

TABLE C-15 PARTICULATES AND SO_2 EMISSIONS
41 NORTH CENTRAL MILLS
(POUNDS PER HOUR)

	BASE CASE		10% FUEL SHIFT and COGENERATION	
	PARTICULATES	SO_2	PARTICULATES	SO_2
AT MILL				
HOG FUEL	199	-0-	221	-0-
COAL	661	5,286	734	5,868
OIL	-0-	3,528	-0-	3,528
AT UTILITY				
COAL	461	3,689	418	3,341
OIL	-0-	273	-0-	247
TOTAL	1,321	12,776	1,373	12,984

	PARTICULATES	SO_2
DIFFERENCE	+52	+208

SOURCE: SRI INTERNATIONAL

is relatively little effect.

For the case with a 10 percent shift in fuel use, and increased self-generation of electricity, the improvement in emissions of particulates and SO_2 are only slight.

South Central States

Sixty-seven mills in the South Central region of the country were analyzed.* In 1976, the mills in this region consumed a total of 640 trillion BTU's of energy. The mills in this region of the country utilize a large quantitiy of self-generated fuels with pulping liquors and hog fuel, accounting for roughly 50 percent of total energy requirements. Natural gas is also a large source of energy, providing about one-third of total energy needs. The balance of energy requirements is supplied by oil (14 percent) and coal (4 percent).

Electric utilities in this region are based on both coal--in the eastern part of the region †-- and natural gas in the western part of the region.** For purposes of this analysis, it was assumed that Alabama Power and Louisiana Light and Power were typical of the generating facilities in the region. Based on the operation of these two utilities for 1975 and 1976, it was estimated that the fuel mix for the various generating plants in the region

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*Includes two census regions: East South Central (4 states) and West South Central (4 states)

†East South Central states: Kentucky, Tenessee, Alabama, and Mississippi

**West South Central states: Arkansas, Louisiana, Oklahoma, and Texas.

was as follows:

Fuel Type	Share (%)
coal	58%
oil	2%
gas	40%

A review of the emission standards for the South Central states has been made, and the results of that work are summarized in Table C-16. Emission limits are assumed to apply to both industrial facilities and electric utility facilities. There is considerable variation in emission limits for the states in this region, but as with the other regions examined, the most rigid standards were selected as being typical for all states within the region.

The net effect on emission of particulates and sulfur dioxides by shifting fuel use in mills in the South Central states are indicated in Table C-17. With increased co-generation at the mills, there will be an improvement in sulfur dioxide emissions, virtually no change in particulates emissions.

Western States

Thirty mills in the western region of the country were analyzed.* In 1976 the mills in this region consumed a total of 205 trillion BTS's of energy. The mills in the Mountain and Pacific Coast states also use large quantities of self-generated fuels. These two energy sources provided nearly 55 percent

*Includes two census regions: Mountain (eight states) and Pacific (three states); Alaska and Hawaii are not included.

TABLE C-16

EMISSION LIMITS FOR PARTICULATES AND SULFUR DIOXIDES

SOUTH CENTRAL STATES
(Pounds per Million Btu Input)

Particulates:

Alabama:	For both old and new equipment of sizes greater than 250 million Btu per hour input, and all fuels: 0.12
Louisiana:	For both old and new equipment, all sizes, and all fuels: 0.6

Assumed control of particulates emissions in all states at 0.12

Sulfur Dixoides:

Alabama:	For all equipment and all sizes, as well as all fuels: 1.2
Louisiana:	For both old and new equipment, all sizes, limits are as follows:

Solid fuels:	1.2
Liquid fuels:	0.8

Assumed control for sulfur dioxides emissions in all states as follows:

Solid fuels:	1.2
Liquid fuels:	0.8

Source: Developed by SRI International

TABLE C-17 PARTICULATES AND SO_2 EMISSIONS
67 SOUTH CENTRAL MILLS
(POUNDS PER HOUR)

	BASE CASE PARTICULATES	BASE CASE SO_2	10% FUEL SHIFT and COGENERATION PARTICULATES	10% FUEL SHIFT and COGENERATION SO_2
AT MILL				
HOG FUEL	1,503	-0-	1,982	-0-
COAL	353	3,528	465	4,651
OIL	-0-	7,985	-0-	7,985
AT UTILITY				
COAL	531	5,306	440	4,397
OIL	-0-	121	-0-	101
TOTAL	2,387	16,940	2,887	17,134

	PARTICULATES	SO_2
DIFFERENCE	+500	+194

SOURCE: SRI INTERNATIONAL

of the total energy requirements. Gas accounted for about one-third, and oil the remainder or almost 15 percent. There was no coal used at any of the western mills.

Western mills purchase 85 percent of their electricity requirements. Since a large share of these electricity supplies come from hydroelectric operations, there would be a negative effect on emissions with increased co-generation at the mills.

A review of the emission standards for the western region has been done, and the results of that work are summarized in Table C-18. Emission limits, applicable to both industrial and electric generating plants, in the western states are similar to those for the balance of the United States. While emission limits are particularly severe in the metropolitan areas of California, the situation is not quite the same in the rural areas, particularly the areas where the mills are located.

The net effect on emissions of particulates and sulfur dioxides from mills in the western states are shown in Table C-19. Since all of the shift is from natural gas to hog fuel for the cases examined, the net effect is only to increase particulates; the absolute amount is not large, but the percentage increase is almost 40 percent. There is no effect on SO_2 emissions.

C-8 OTHER IMPACTS AND INFLUENCES

There are at least five general external factors that can significantly affect the individual decisions to install TES systems and increase the use of wood

TABLE C-18

EMISSION LIMITS FOR PARTICULATES AND SULFUR DIOXIDES

WESTERN STATES
(Pounds per Million Btu Input)

Particulates:

Oregon:	For all equipment and all fuels, emission limits are 0.2 grans/scf or 0.1 grans/scf based on heat input.
California:	For all equipment and all fuels, emission limits are 0.3 grans/scf.

Assumed control for particulates emissions in all states at 0.1o

Sulfur Dioxides:

Oregon: For both old and new equipment of sizes greater than 250 million Btu per hour input, and all fuels:

Solid fuels:	Decreasing from 1.6 to 1.2
Liquid fuels:	Decreasing from 1.4 to 0.8

California: For all equipment of all sizes, and all fuels: 0.2 percent SO_2 by volume.

Assumed control for sulfur dioxides emissions in all states:

Solid fuels:	1.0
Liquid fuels:	0.6

Source: Developed by SRI International

TABLE C-19 PARTICULATES AND SO_2 EMISSIONS
30 WESTERN MILLS
(POUNDS PER HOUR)

	BASE CASE		10% FUEL SHIFT and COGENERATION	
	PARTICULATES	SO_2	PARTICULATES	SO_2
AT MILL				
HOG FUEL	339	-0-	505	-0-
OIL	-0-	2,015	-0-	2,015
AT UTILITY				
VIRTUALLY ALL HYDROELECTRIC -- NO EMISSION CHANGE				
TOTAL	339	2,015	505	2,015

	PARTICULATES	SO_2
DIFFERENCE	+166	-0-

SOURCE: SRI INTERNATIONAL

waste as hog fuel in the integrated pulp and paper mills.

1. The EPA and regional efforts to prevent significant deterioration in air quality have generally resulted in delays and cancellations of new industrial plant construction and expansions of existing plants. The trend has been to withhold permits until planners of new plants or expansions can demonstrate not only that the new facility will not increase overall site emissions, but that an overall reduction of emissions will be obtained in the area. This net reduction can be obtained by buying out and/or closing down other emission sources or by substitution of materials or processes. On the East Coast, for example, Volkswagen was to pay for resurfacing county roads with an asphalt that was especially nonvolatile in order to more than compensate for the hydrocarbon emissions of a painting booth at an automobile plant. On the West Coast SOHIO is being pressured to pay for removal of SO_2 from the local utility emissions to overcompensate for the SO_2 that would come from tanker operations at a proposed pipeline terminal in Long Beach. For every pound of SO_2 emitted at the terminal, 1.2 pounds of SO_2 are to be removed from existing emissions sources.

The pulp and paper industry is growing principally by expansion and is faced with this same sort of requirement. The potential for use of more hog fuel and additional cogeneration can put this industry in an enviable position in respect to its ability to expand while reducing atmospheric emissions when the coal and oil combustion at the mill and its supplying utility are included in the reckoning.

2. The pulp and paper mills may generate all their required electricity and steam; may buy a portion of their electricity; or may buy their total electricity requirement. The decision to take one of these three paths has been greatly influenced by the local prices of electricity and gas, and the investment required for raising steam and generating electricity. The increasing prices of industrial electricity and fossil fuels will make cogeneration more economic in the future.

Even in this changing economic environment, some mill owners may not be prepared to make the investment in generating facilities. The possibility of utility investment and ownership needs to be reconsidered.

Generally it is assumed that the term "cogeneration facility" applies to a facility that produces both process steam and electricity, with ownership either by utilities, industrials, or co-ownership by both the industrial and utility consumers. The question of ownership could have important consequences, for instance, on siting reviews and regulation and application of the Public Utility Holding Company Act to joint ventures and public utility commission regulation.

Jointly-owned cogenerating facilities will probably not develop as an important source of electrical and other energy unless the facilities are exempted from certain state and federal utility laws and regulations. Regulatory aspects that may affect cogeneration installation include Internal Revenue Service rules relating to tax credits and depreciation deductions; anti-trust laws that restrict discriminatory pricing and preferential service; rate regulation limiting demand charges or back-up energy charges; and policies pertaining to utility practices in transmission and wheeling of excess power.

It is the belief of the Edison Electric Institute (EEI)* that there does not now exist any legal or regulatory barrier to cogeneration that cannot be resolved by the utility and the customer and state regulatory agencies working together.

Several wood industry plants now have short-term arrangements to furnish power to utilities. A good example of the cooperation that can exist is the steam-electric power plant operated for the Eugene Water and Electric Board of Eugene, Oregon. This is a 32-megawatt (MW) unit using hogged wood and bark from nearby mills. The plant provides steam for Eugene's steam heat utility on a year-round basis, and the balance of its steam capacity is sued to generate electricity for eight months. It is on standby for electric power generation for the remaining four months each year.

3. Variation in U.S. forests require comparable variation in the management of these resources. These management practices, in turn, affect the availability and economics of wood waste that might be useful as hog fuel.

*National Energy Act, Part 3, Vol. II, Series No. 95-245.

Timber may be harvested in one of several ways--clearcut, shelterwood cut, selective cut, and other methods. Each method has advantages for particular forest types and locations. Clearcutting for economic reasons may leave an area poorly equipped for reproduction as well as aesthetically offensive during the regeneration period. The issue was partly defused by the passing of the National Forest Management Act of 1976 that issued a set of guidelines on clearcutting on federal forest lands. Adequate consideration must be given to influence on water sheds, cost-benefit evaluations, marginal lands, and sustained yield.

Where shelterwood cutting is practiced, part of the stand is removed in one cut, and the balance is left to reseed the area and shelter young seedlings. Thinning is carried out at 15-year intervals and harvesting at 30-year intervals. For some of the warmer and drier sites for Douglas fir, especially on the eastern and southern edges of the Douglas fir belt, shelterwood cutting may be the best method.

Selective cutting is practiced in forests of mixed ages or in forests both of mixed age and mixed species, and is often the cheapest method of harvesting. The logger takes the more valuable species and leaves the rest, including standing dead trees. As prices rise, another logger moves in to repeat the process, taking still more of the growing stock.

In many parts of the country (especially in the northeast and south), small portable sawmills are established to harvest a relatively minor volume of timber from a privately owned forest. While the method of operation may be technically inferior, they do produce significant quantities of lumber from stands that would not interest larger mills.

Of major importance also is the disposal of slash. Some debris must be allowed to remain to supply soil nutrients or to protect the area against erosion. Where wood chips have significant value for pulp manufacture, it is economic to remove more of the defective wood than where no such outlet exists, but in any event, some wood so defective that it is valueless for any purpose is likely to remain. Such defective materials as are currently discarded could provide fuel for steam and electric power generation.

Regulations on slash disposal specify that slash left from logging operations must be reduced to a predetermined height from the ground on all Forest Service sales.

There are questions as to how much slash disposal should be carried out. The work is expensive, and not all slash can or need by disposed. Removal of all forest material on even relatively small areas of land may, with unstable soil conditions and high intensity rainfall, permit serious flood damage and erosion. The depth and character of the organic mantle on the ground may largely control damage to the roots by surface fires, especially of the more shallow-rooted trees.

Overall, a certain amount of debris on forest floors is desirable. Some soils require more nutrients than others. They also differ in their water holding capacity and their susceptibility to erosion. Harvesting procedures can be adjusted to minimize deleterious consequences on sites of this kind and the related effects on forest regeneration. Forest management policies can have both plus and minus aspects from the standpoint of potential fuel volumes available from the logging residues such as slash.

4. The energy-efficiency improvement goals set by the Federal Energy Administration are based solely on purchased energy--electricity and fossil fuels. The 1980 target of a 20 percent decrease in energy use per unit of production from 1972 levels for the paper industry will logically include increased use of hog fuel and cogeneration. The banning of new gas-fired boilers will also hasten the transition to increased hog fuel use. The decisions to use systems such as TES to increase hog fuel use should consider these factors as well as the economics.

5. Logging residues in most instances will need to be transported to concentration points or to the mill site by truck delivery. Mill trucks used within the industry have capacities up to 20 tons or more. The trucks are carried on 10 or 12 wheels. Highway regulations vary materially among states but generally limit the load for single axle vehicles to between 18,000 and 24,000 pounds. Tandem axle vehicles are therefore used in the majority of cases for transporting timber products. Restricted hour operating permits are required in some counties for the larger vehicles. There are also specific limits on

height, length, and width of vehicles that will likely be more important than gross weight limits for bulky logging residues. The dimensions also affect loading practices and terminal facilities. The general trend in limits over time has been upward.

Inasmuch as the logistics of transportation and handling add considerably to the value of the materials, it has been assumed for the purposes of this study that hauling will be limited to perimeter counties and that the mill will seek hog fuel supplies from sawmill operations no further afield than the surrounding counties.

C-9 ECONOMIC FACTORS AND SENSITIVITY ANALYSES

SRI assisted Boeing in the economic analyses by supplying a basis for some of the economic factors and by performing selected sensitivity calculations around the selected typical values of the economic factors.

The typical values for the economic factors of significance were set at:

C_p, purchased electricity ($/kilowatt-hour)	0.024
C_f, purchased gas or oil ($/million Btu)	2.00
I, TES investment ($)	1,000,000*
M_h, operating and maintenance cost of solid fuel boiler ($/million Btu output)	0.10
R, annual capital recovery factor	0.27
E_h, solid fuel boiler efficiency (Btu out/Btu in)	0.65
E_f, gas or oil boiler efficiency (Btu out/Btu in)	0.80
K, fraction of year for TES operation	0.6

* Subsequent analysis indicated this would more likely be in the $500,000-$750,000 category.

ΔW_f, reduction of fossil fuel boiler steaming rate resulting from TES use (pounds/hour) 60,000

ΔE, incremental cogeneration resulting from TES use (kW) 1,680

These economic factors were incorporated in a single equation to yield a single figure of merit, the cost that could be incurred for the incremental hog fuel, C_h, in a system of economic parity. Dry wood waste has an energy content of about 18 million Btu per ton, and Weyerhauser estimated that the cost of this additional hog fuel would approach \$25 per ton. C_h values of about \$1.40 per million Btu indicate an economically viable system and, coincidentally, allow substitution of coal to be considered where hog fuel is unavailable.

SRI varied each of the economic factors through a reasonable range while holding all other factors at the stated typical value in order to obtain a measure of the sensitivity of the hog fuel cost (the selected figure of merit) to each factor. The results of the calculations are graphically summarized in Figures C-4 through C-12.

The relationships were generally linear except for the sensitivity of hog fuel cost to the reduction in steaming rate and the fraction of the year for the TES utilization.

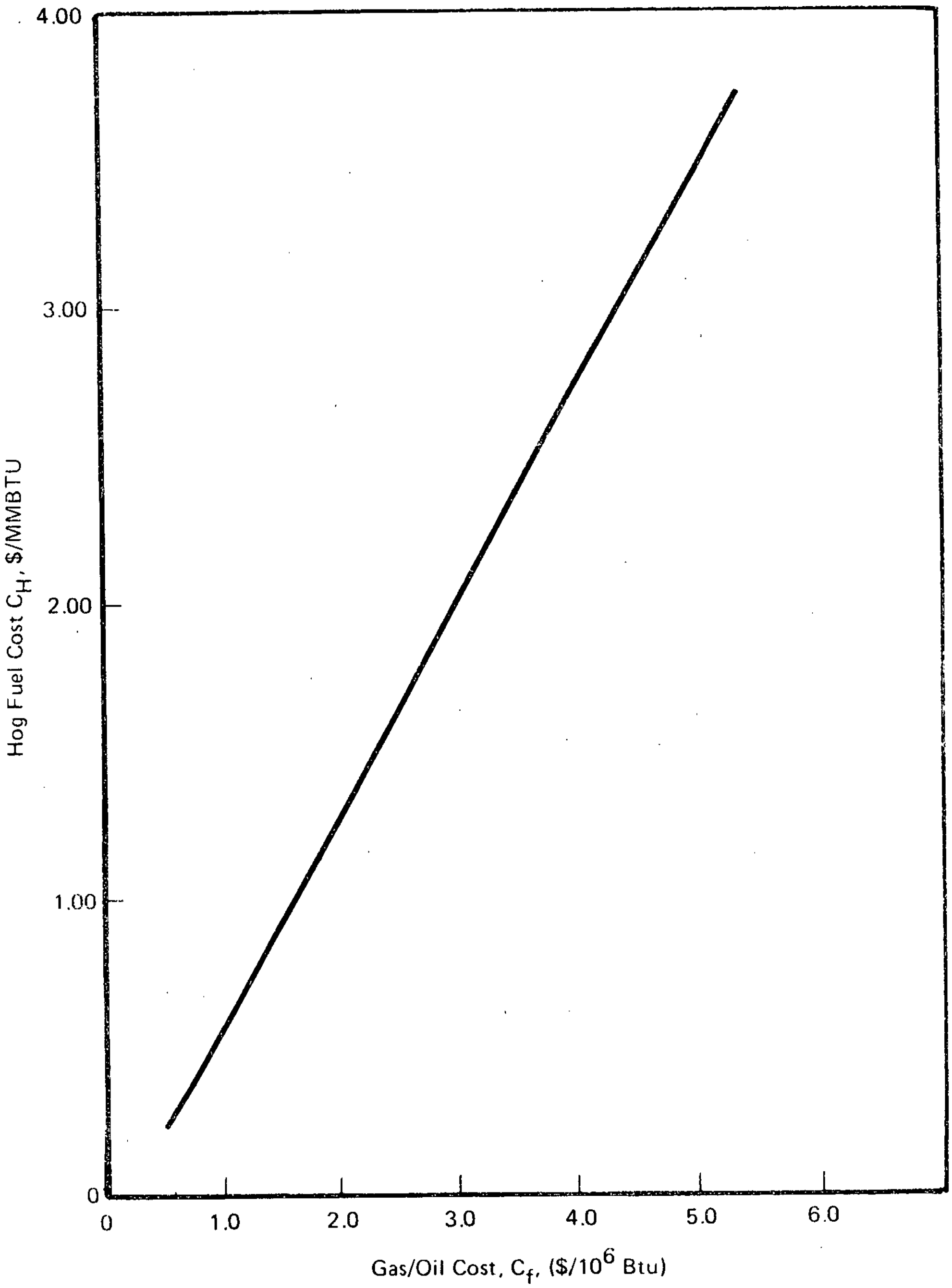

Figure C-4. Sensitivity of Hog Fuel Price to Gas/Oil Cost

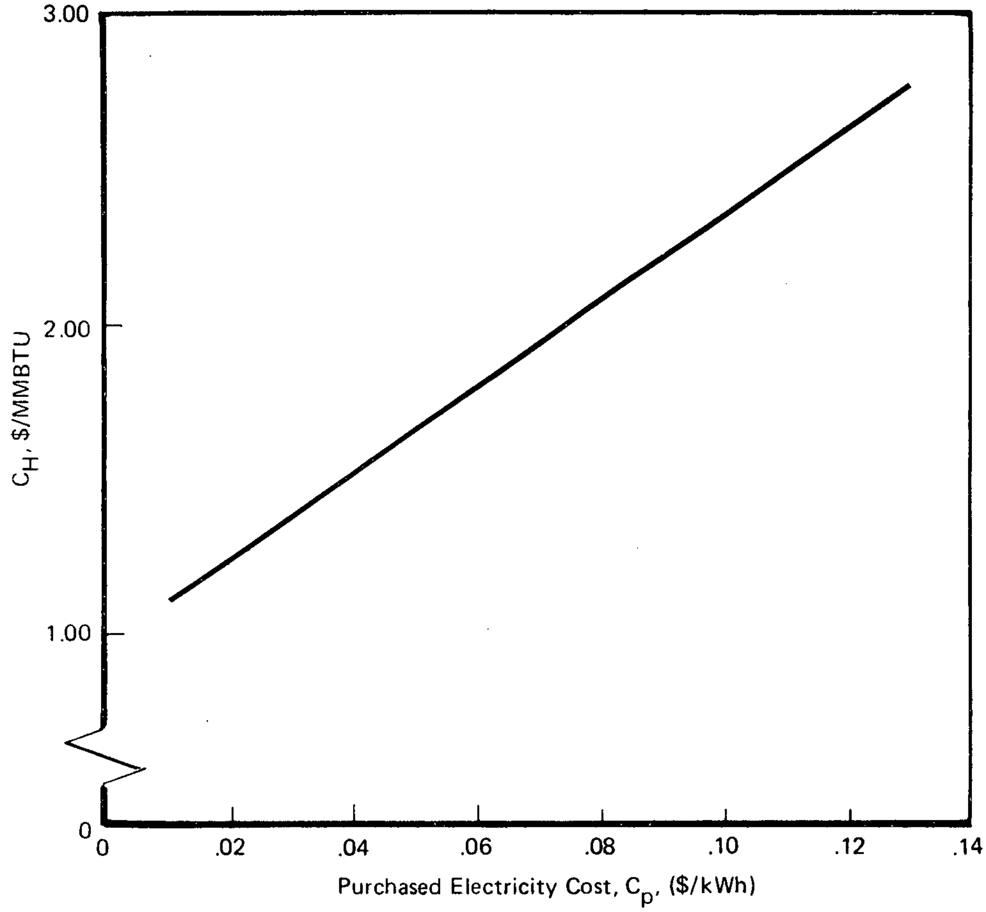

Figure C-5. Sensitivity of Hog Fuel Price to Electricity Cost

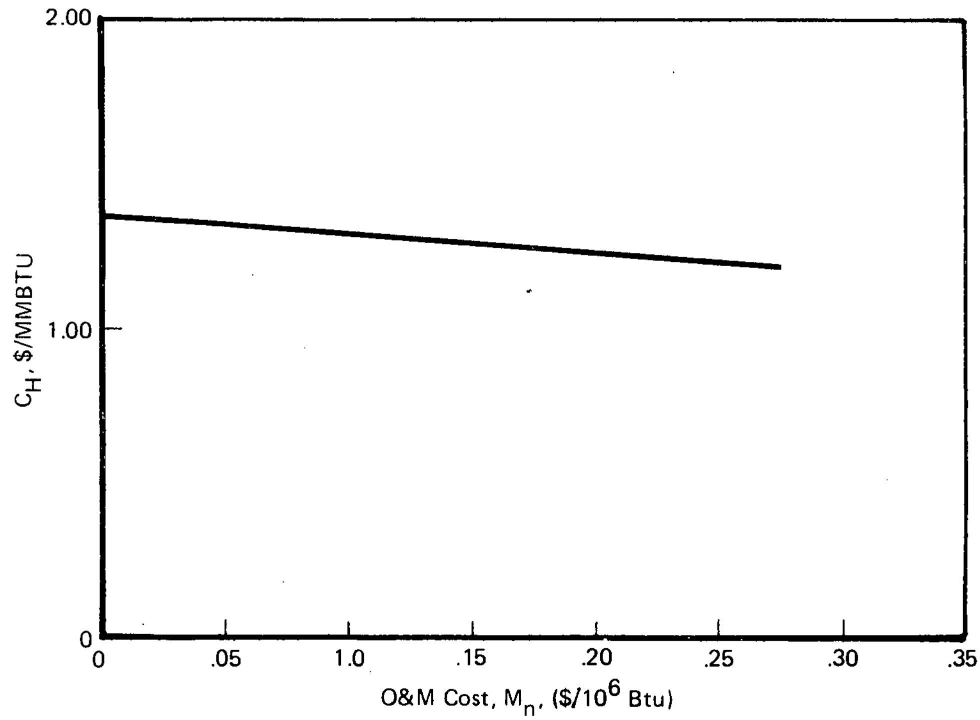

Figure C-6. Sensitivity of Hog Fuel Price To Solid Fuel Boiler O&M Cost

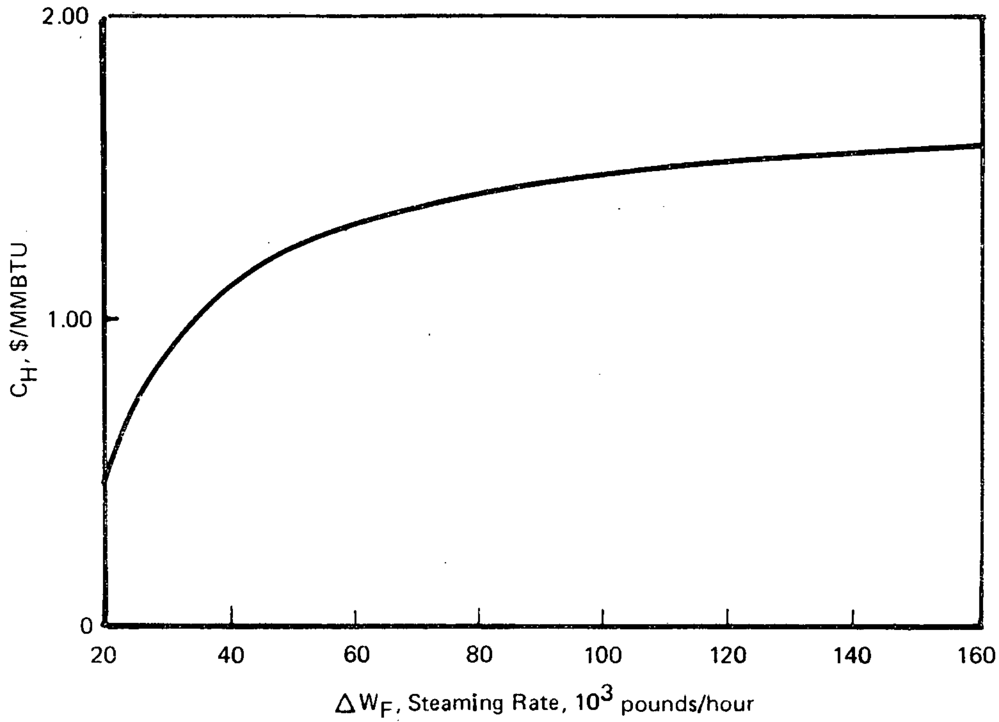

Figure C-7. Sensitivity of Hog Fuel Price To Steaming Rate Increment

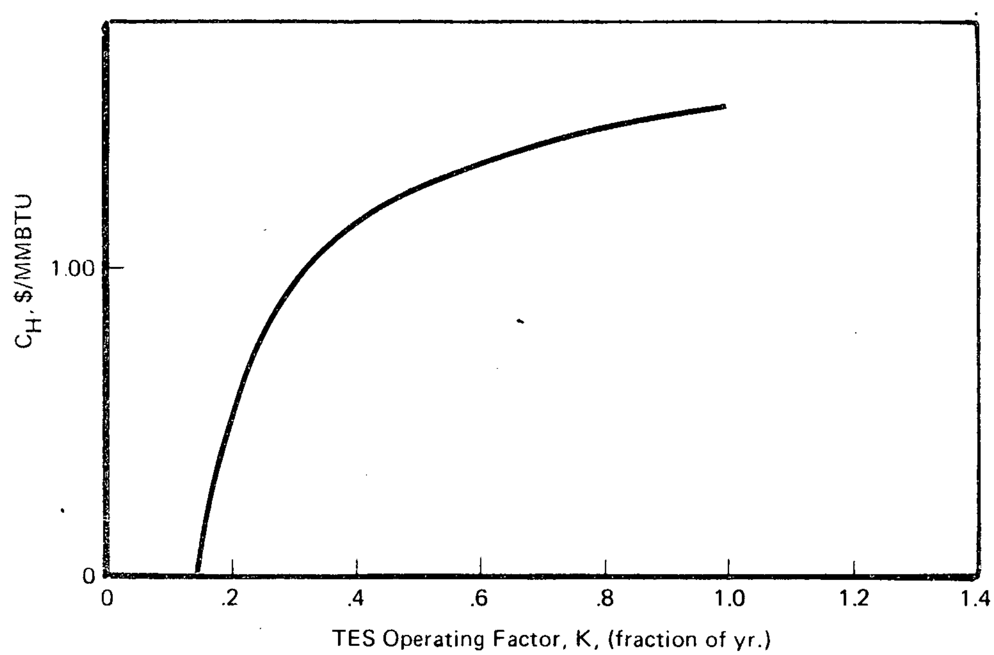

Figure C-8. Sensitivity of Hog Fuel Price To Annual Operating Factor of TES System

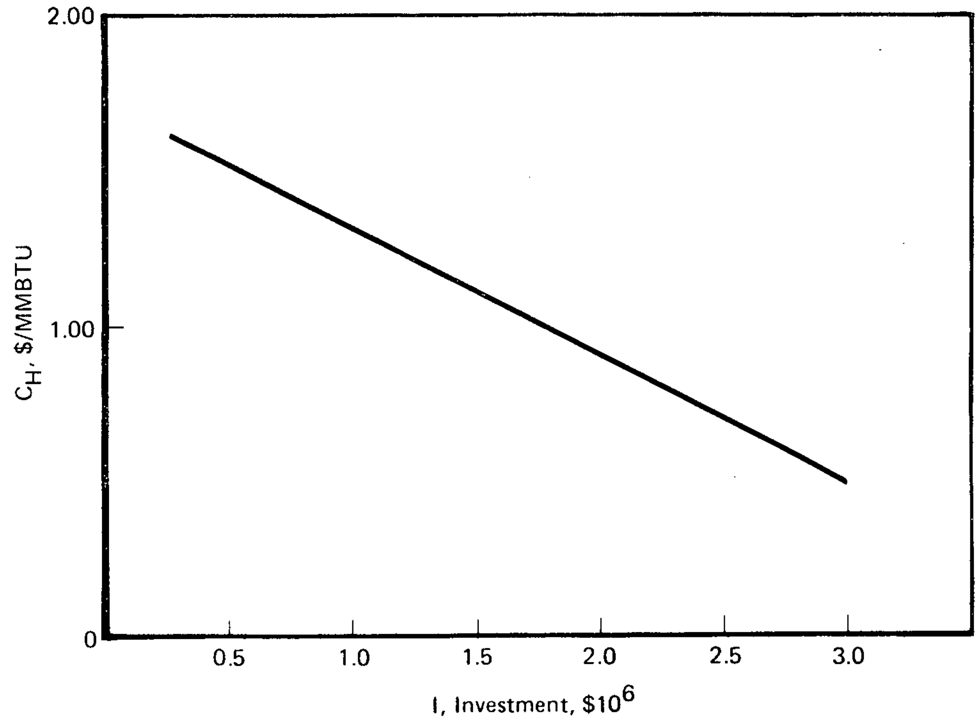

Figure C-9. Sensitivity of Hog Fuel Price to TES Investment

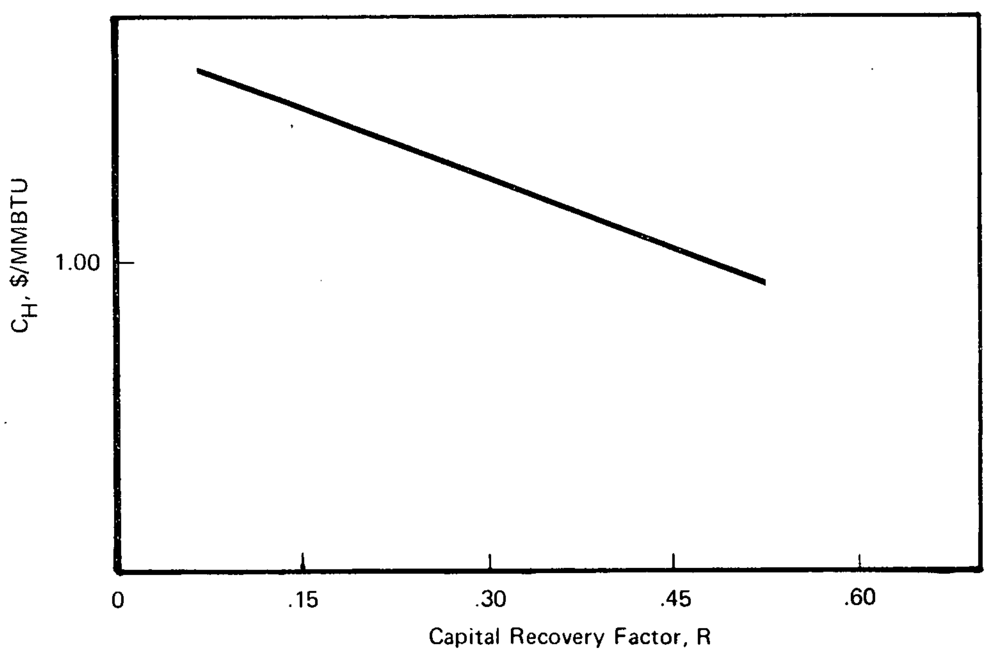

Figure C-10. Sensitivity of Hog Fuel Price to Capital Recovery Factor

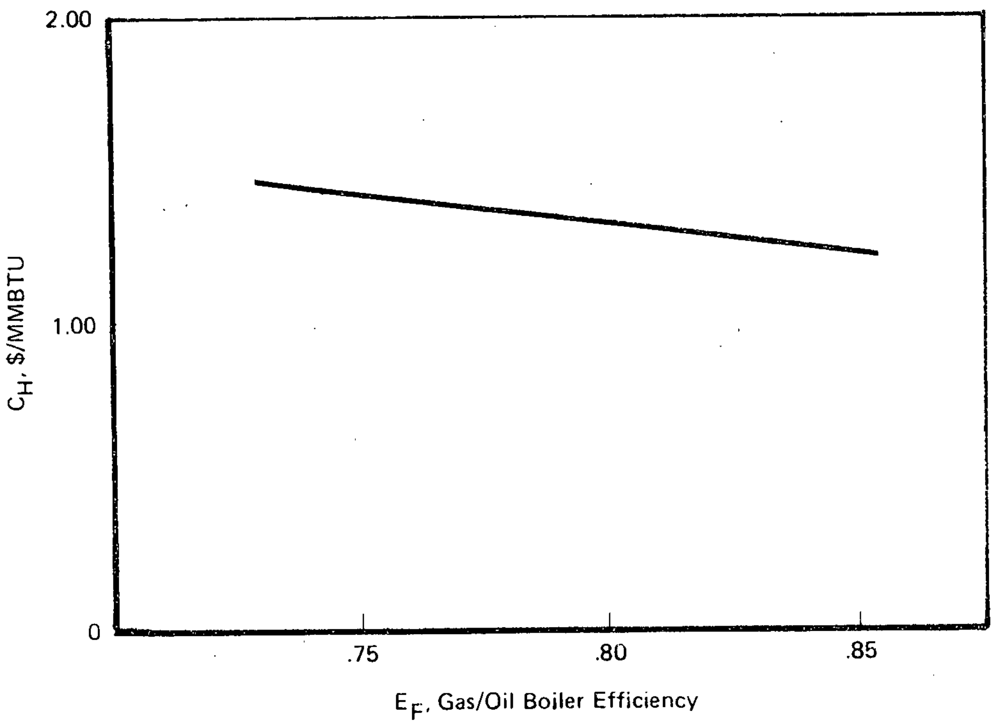

Figure C-11. Sensitivity of Hog Fuel Price to Gas/Oil Boiler Efficiency

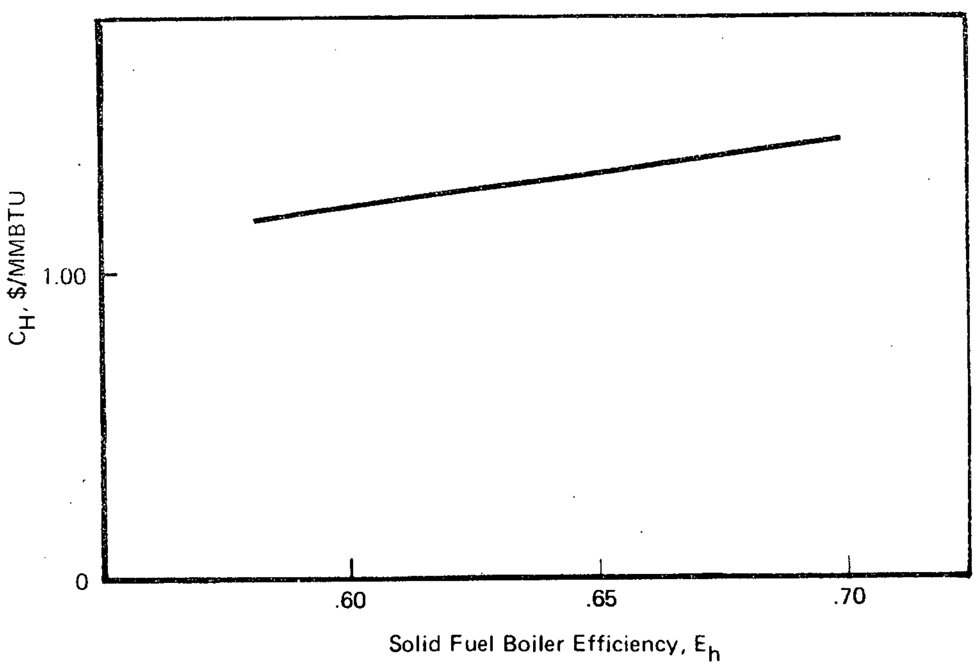

Figure C-12. Sensitivity of Hog Fuel Price to Solid Fuel Boiler Efficiency

The hog fuel cost was found most sensitive to the cost of the fossil fuel it would be displacing, and it was also quite sensitive to the cost of the purchased electricity that would be displaced by the incremental cogeneration. The TES investment and the capital recovery factor selected to obtain a return on that investment also have a significant effect on the hog fuel cost that can be allowed while maintaining economic parity.

Operating and maintenance cost variations and variations in the efficiencies of the fossil fuel and hog fuel boilers are of less signficance in their impact on allowable hog fuel costs.

The typical value of the annual operating factor is higher on the curve of allowable hog fuel cost for variations of this economic factor, but the curve is steeper, so additional annual use of the TES can yield worthwhile economic benefits.

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