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ENERGY

CONSERVATION

# MASTER

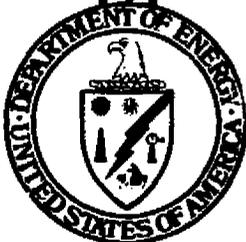APPLICATIONS OF THERMAL ENERGY STORAGE TO PROCESS HEAT STORAGE AND RECOVERY IN THE PAPER AND PULP INDUSTRY

Final Report, September 1977—May 1978

By
J. H. Carr
P. J. Hurley
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September 1978
Date Published

Work Performed Under Contract Nos. EC-77-A-31-1034
EC-77-C-01-5082

Boeing Engineering and Construction Company
Seattle, Washington

# U. S. DEPARTMENT OF ENERGY

## Division of Energy Storage Systems

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

FINAL REPORT FOR THE PERIOD SEPTEMBER 1977 - MAY 1978

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Date Published - September 1978

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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 $3.2 \times 10^6$ 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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# TABLE OF CONTENTS

## 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

Wood waste ("hog") fuels supply up to 40% of process demand

**Pulping liquor recovery boilers** — 550,000 lb/hr →

**Hog fuel boilers** — 375,000 lb/hr →

**Fossil fuel boilers** — 50,000 to >200,000 lb/hr
125,000 lb/hr average →

**Pulp & paper mill**
• Digesters
• Evaporators
• Bleach plants
• Chlorine plant
• Pulp machines
• Paper/paperboard machines
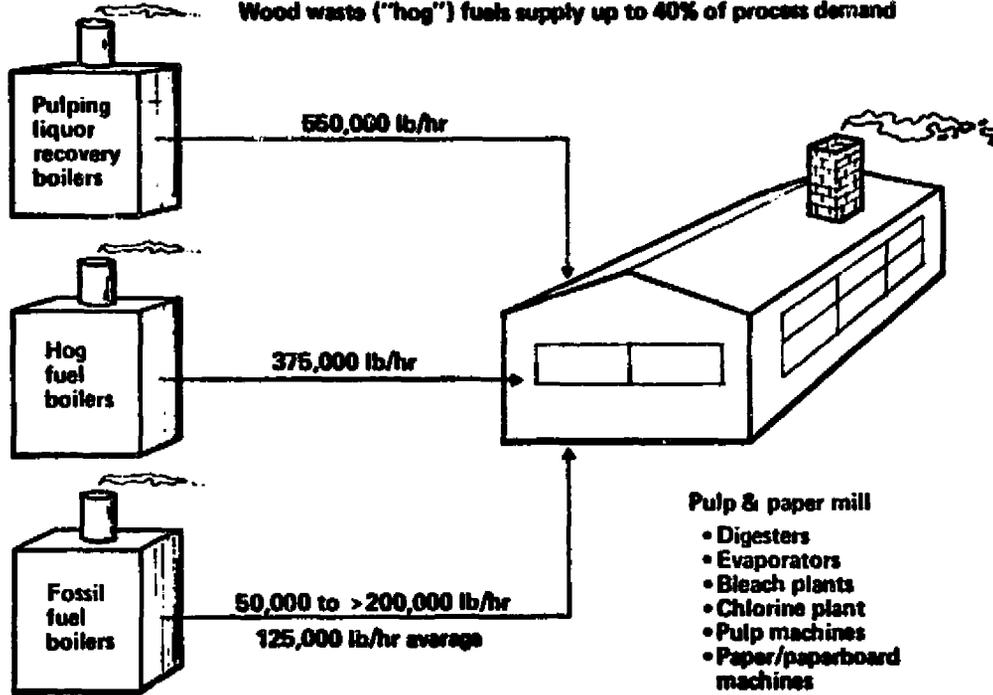
# Application of Thermal Energy Storage

• Energy storage can reduce fossil fuel consumption for load following by one-half

**Recovery boilers** — 550,000 lb/hr →

**Hog boilers** — 435,000 lb/hr (+60,000 lb/hr) → **Storage** → 375,000 to 495,000 lb/hr →

**Fossil boilers** — 50,000 to >100,000 lb/hr
65,000 lb/hr average
(-60,000 lb/hr) →
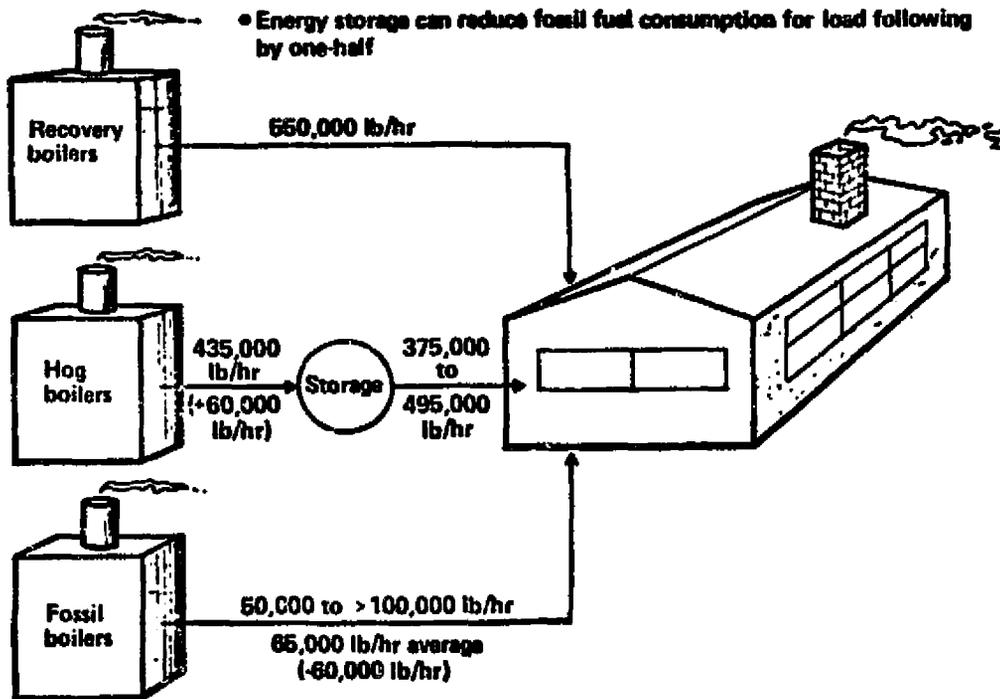
*Figure 1-1. TES Application Concept*

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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.

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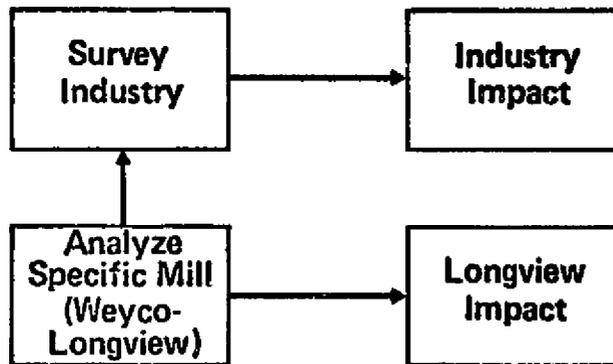


Figure 1-2. Study Approach

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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

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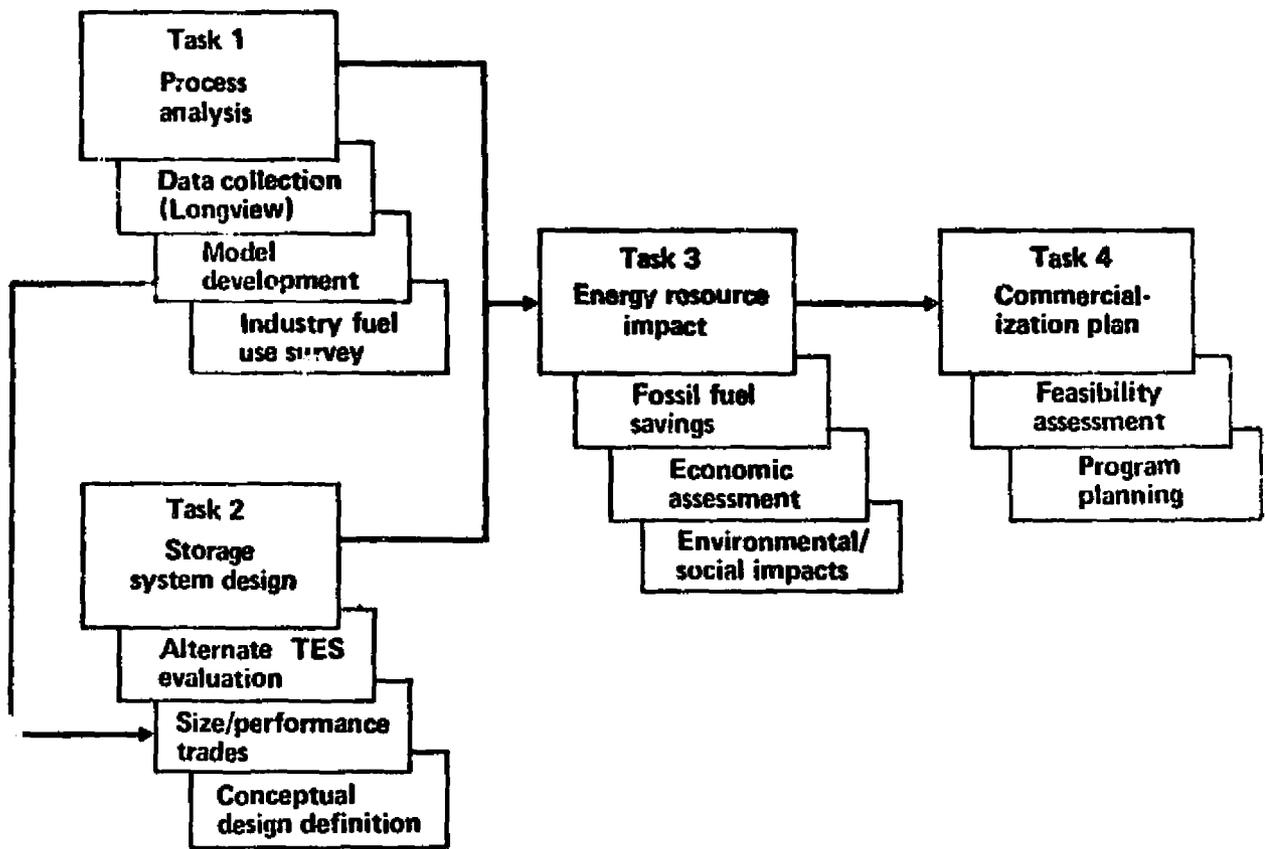
Figure 1-3. Study Organization

| 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 | |



Mechanical Component Cost Comparisons (est.)

• 100,000 lb/hr steaming rate

Rock/glycol TES

Relative Cost

Range for variable and constant pressure accumulators

Initial size estimate

Storage Time, Hours
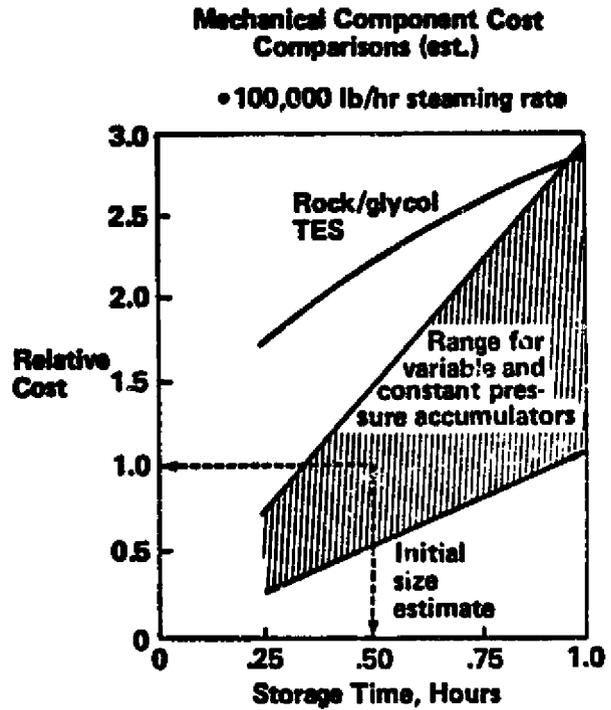
Figure 1-4. Storage System Candidates and Selection

● 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*

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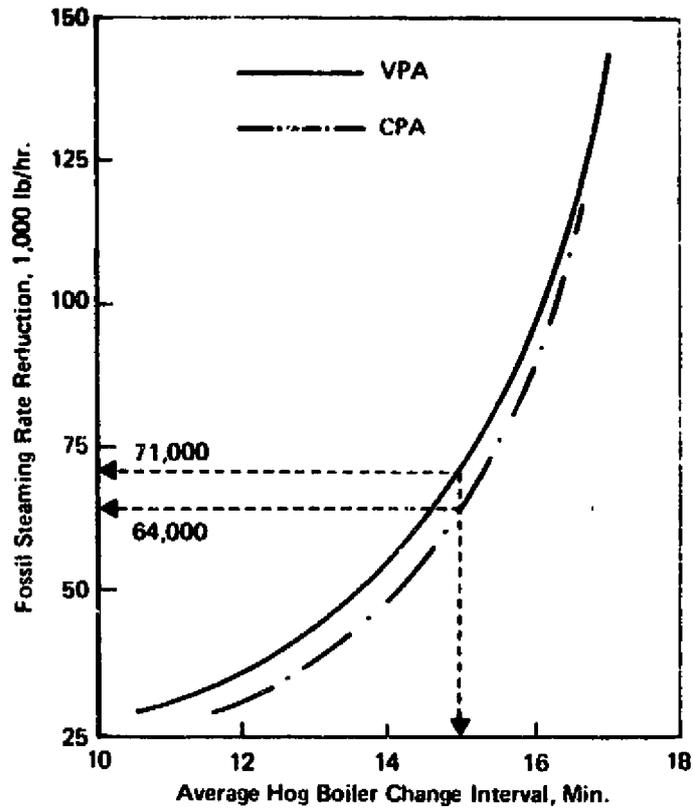
*Figure 1-6. Steam Accumulator Performance*

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

72 - ¼" dia. holes per nozzle

Circulation pipe

Nozzle detail

# 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
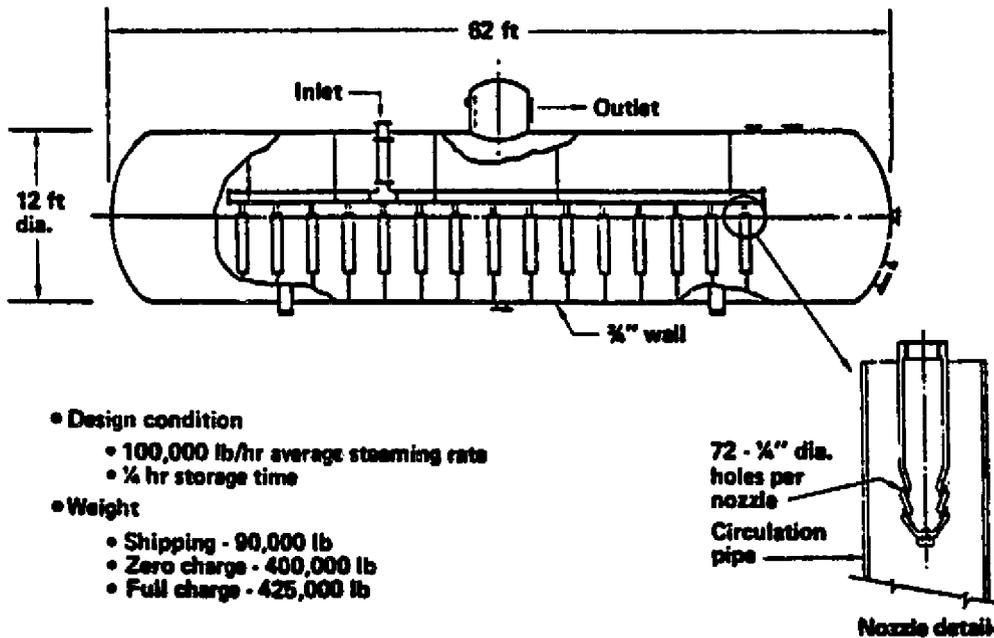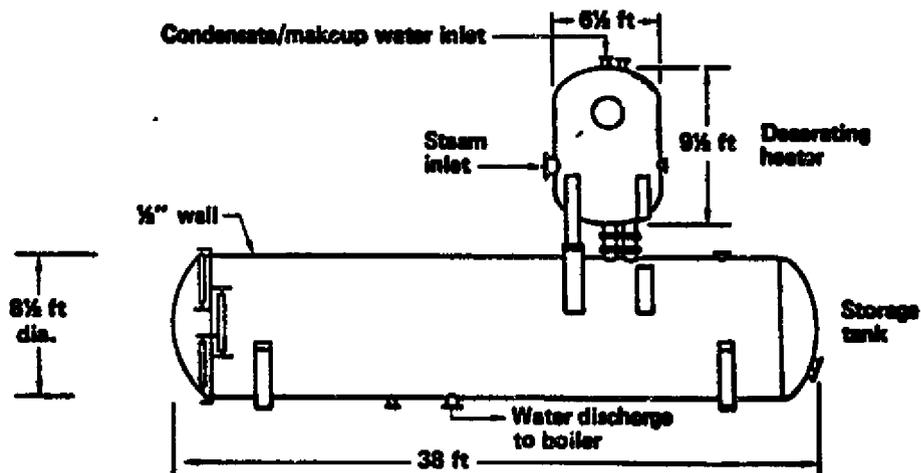
*Figure 1-7. TES Conceptual Design Summaries*

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| 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    117
  American Paper Institute

- Number of mills contacted    55

- Number of mills with current fuel substitution potential
    - 12 months/year    8
    - 6 months/year    4
    - Total equivalent, 12 months/year    8

- Number of mills with current programs that will result in fuel    6
  substitution potential by 1980

- Estimated average fossil/hog steam generation transfer potential    60,000 lb/hr

- Annual fossil fuel reduction potential at 1,100 BTU/lb steam,    $3.2 \times 10^6$ bbls
  80% boiler efficiency, 93% operating efficiency, $6.3 \times 10^6$ BTU/bbl

*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 | | $79.8 \times 10^6$ | $79.8 \times 10^6$ |
| At the utilities | | -- | $32.7 \times 10^6$ |
| Total | | $79.8 \times 10^6$ | $112.5 \times 10^6$ |
| | | (12.7 MM BBL) | (17.9 MM BBL) |

*Figure 1-10. Long Term Fuel Substitution Potential*
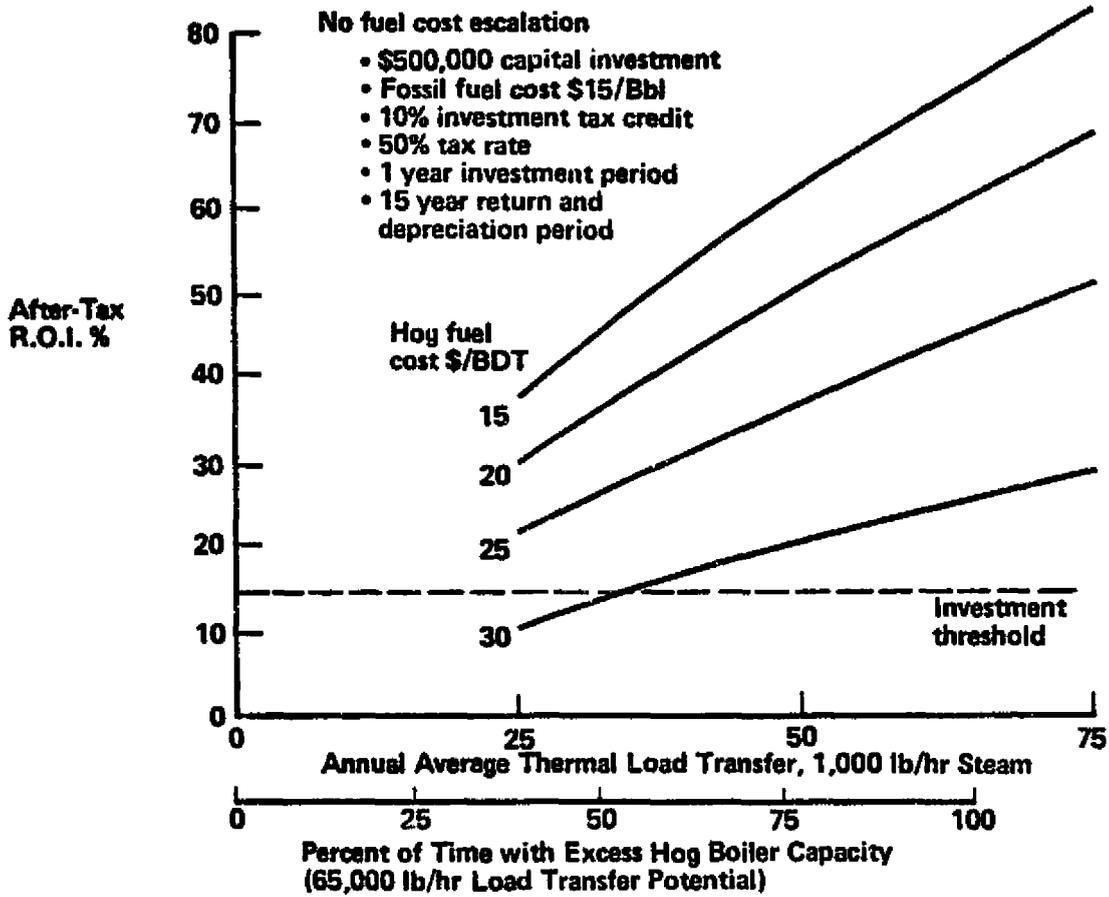
Figure 1-11. Return on Investment — No Incremental Electrical Generation

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| Program Element | Activity | Year 1 | Year 2 | Year 3 |
|---|---|---|---|---|
| D.O.E. Demonstration Program | System Design | Performance analysis — Data analysis / Design review ▽ ▽ ▽ Demonstration system specification ▽ & preliminary demonstration plan — Industrial parti-△ cipant commit-ment | | |
| | Fabrication/Procurement | Accumulator on-dock ▽ ▽ Computer on-dock / Control system checkout complete ▽ — Shop drawings release △ △ Start coding | | |
| | Installation & Checkout | Installation checkout ▽ ▽ Demonstration system checkout complete — A&E complete △ | | |
| | Performance Demonstration | Demonstration plan update ▽ Winter performance data ▽ | Summer performance data ▽ | |
| Industrial Implementation | Industry Briefings | Schedule & agenda ▽ Industy expressions of interest ▽ △ Market assessment — △----△ Industry briefings | | |
| | Selected Plants Economic Analysis & Preliminary Design | Data analysis ▽ ▽ Performance analysis / Preliminary design & ▽ economic analysis (typ.) — Plant no. 1 — Plant no. 2 — Plant no. 3 — Plant no. 4 — Plant no. 5 | | |
| | Industrial Procurement | | Industry go-ahead decision ▽ Specification release Contract ▽ ▽ award | First commercial installation on-line ▽ |

*Figure 1-12  Commercialization Plan Activity Phasing*

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## 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.

    o   Typical installations will permit fossil fuel savings in the order of 100,000 bbl/yr

    o   These systems can be implemented today

    o   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.

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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 ps:g 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).

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No. 11 Hog Fuel

No. 9 Oil/Gas

No. 7 Oil/Gas

No. 6 Oil/Gas $H_2$

No. 8 Oil/Gas

No. 1 & 2 Sulfite Recovery

No. 10 Kraft Recovery

600 psig header

600 psig Load

No. 5

No. 4

No. 3

No. 2

No. 1

Mech. drive turbines

200 psig Process Load

140 psig header

40 psig header

140 - 40 psig Var. pr. acc.

Cond. ret.

140 psig D.A.

Cond. Stor.

40 psig D.A.

140 psig Con. Pr. Acc.

140 psig Process Load

40 psig Process Load

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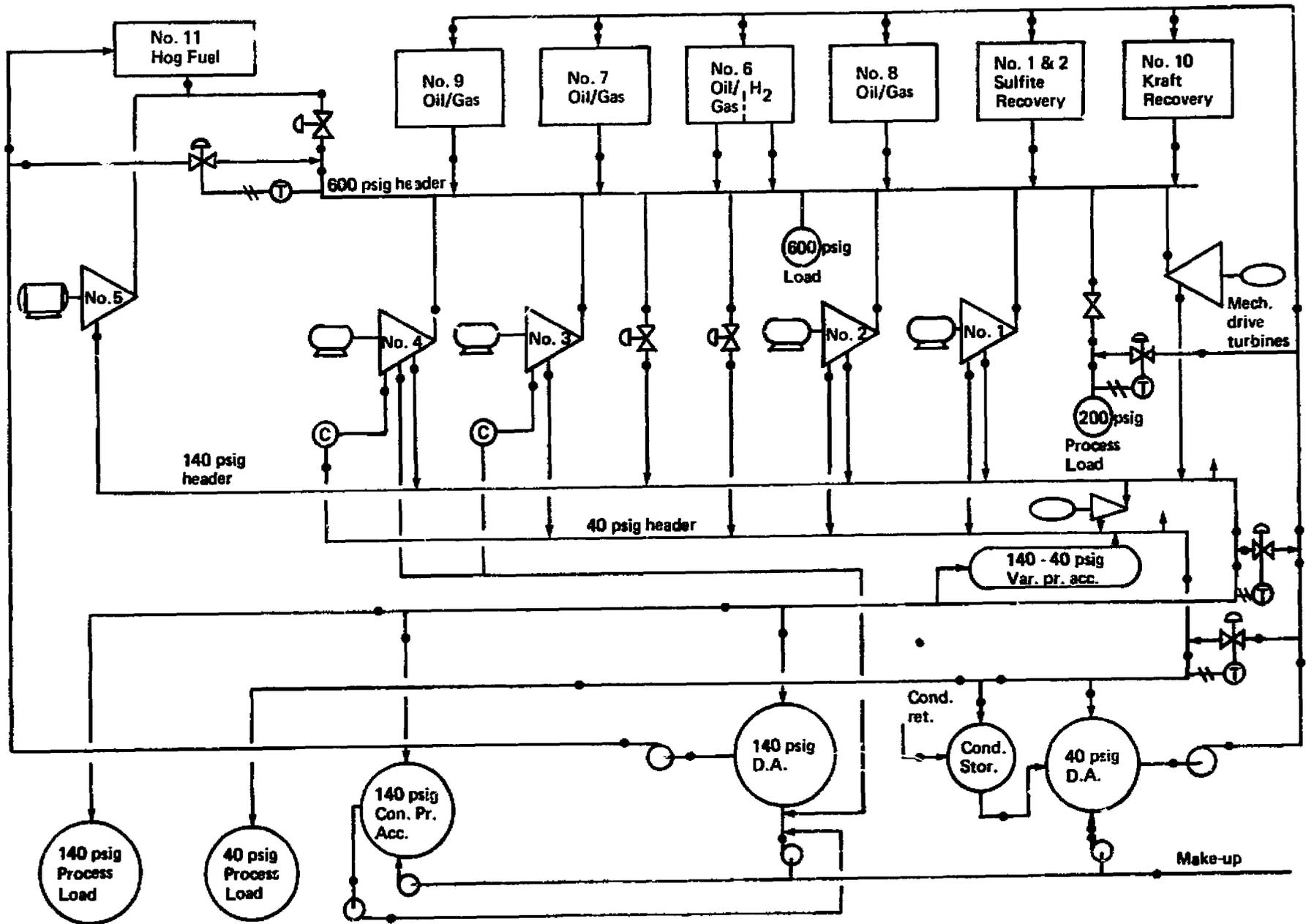
*Figure 2-1. Longview Plant Schematic for Thermodynamic Model (With Storage)*

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.

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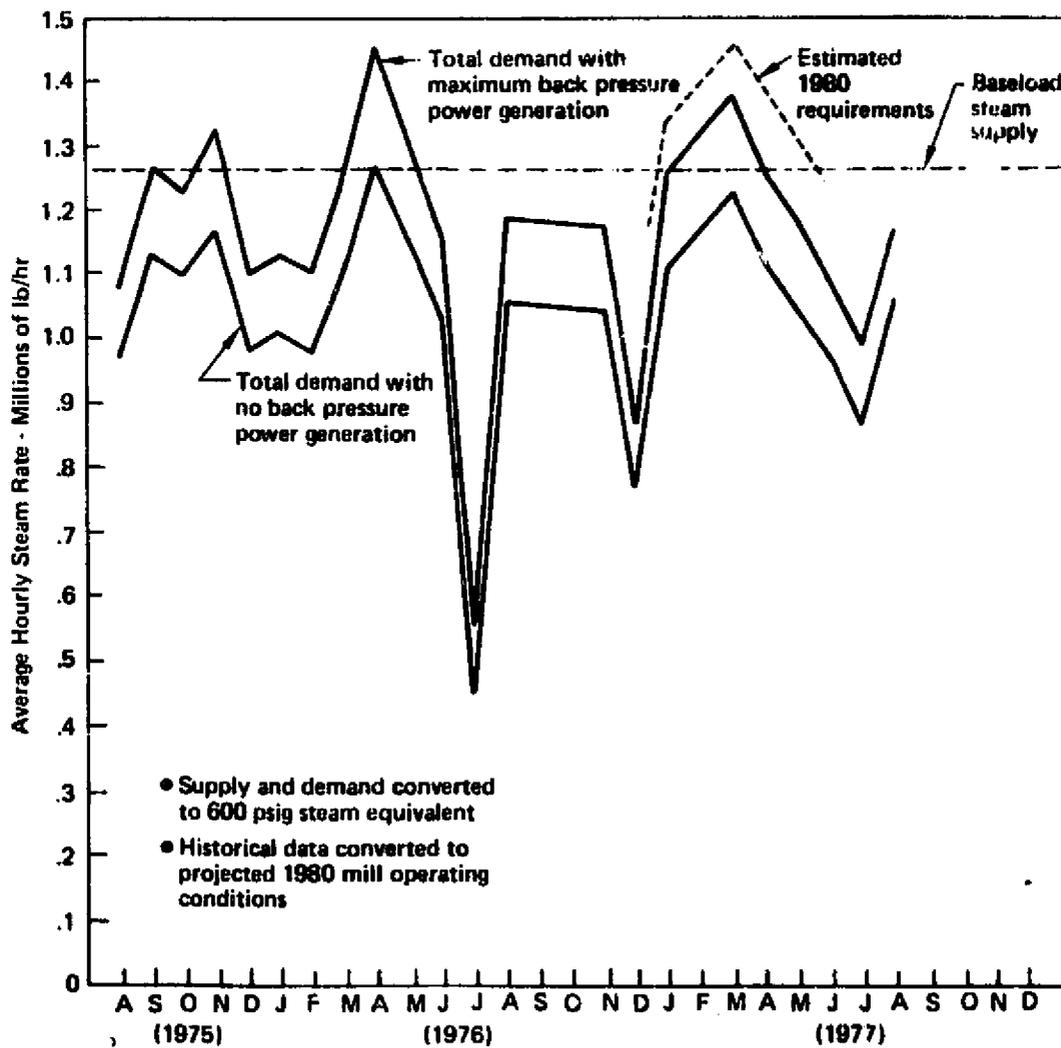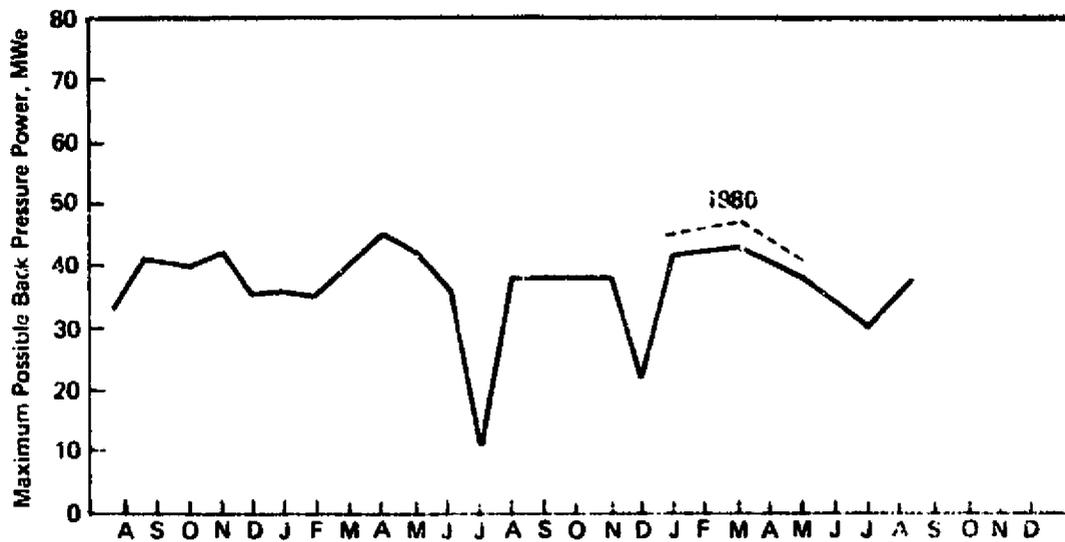
Figure 2-2. Longview Demand and Baseload Boiler Capacity

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 taoles 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.

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## 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 down-ward by 75M#/HR | 125 |
| Sawmi 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 $\pm$ 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

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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 pressu.e 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

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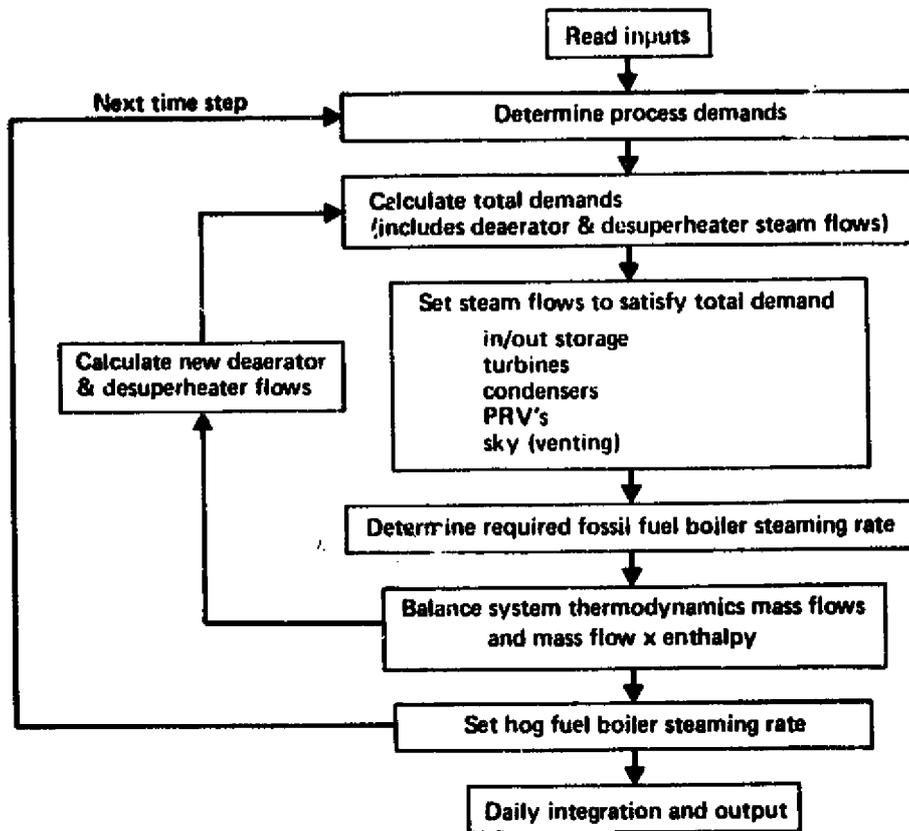
Figure 2-3. Industrial Process Heat Math Model Schematic

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 input to arrive at the proper 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

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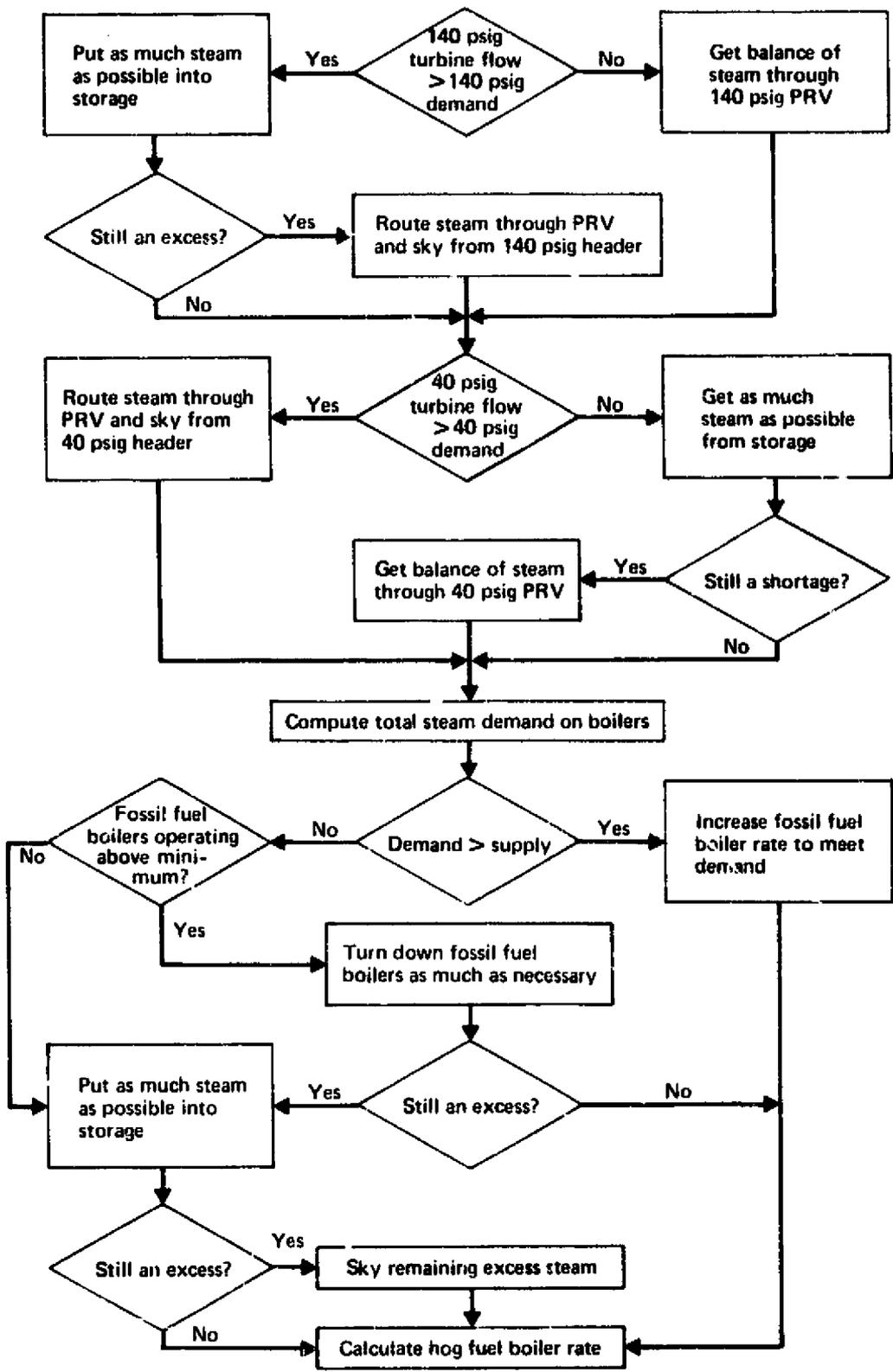
Figure 2-4. Control Logic (Variable Pressure Accumulator)

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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 flow, 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 firs. purpose. After thermodynamic calculations a· ᵤ 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:
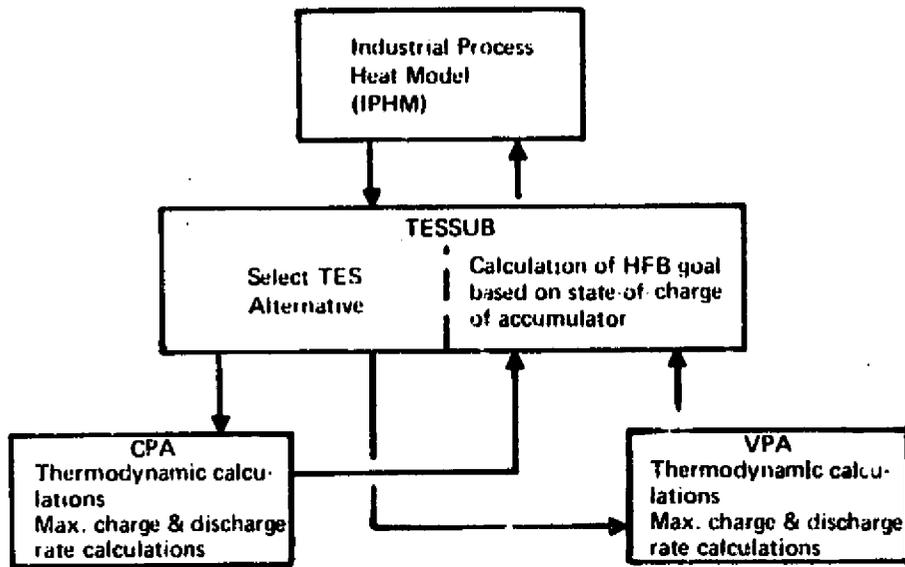
*Figure 2-5. Information Interface Between IPHM and Storage Algorithms*

(mass) $\quad \dfrac{dm_f}{dt} = \dfrac{dm_{g,c}}{dt} - \dfrac{dm_{g,d}}{dt}$ $\qquad\qquad$ (2-1)

(energy) $\quad d(m_f h_f) = \left( h_{g,c} \dfrac{dm_{g,c}}{dt} - h_{g,d} \dfrac{dm_{g,d}}{dt} \right) dt$ $\qquad$ (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:

   $h_{g,c} = h_{g,d} = h_g$ $\qquad\qquad\qquad\qquad\qquad$ (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 ($360^0 - 290^0 F$)

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3. The latent heat of vaporization of the water can be express·d as

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

where a, b, and c determined by a nonlinear regression curv· fit to

Steam Table data, e.g., a = 1060.54, b = -0.249, c = -0.000 $\cancel{3}$4

4. The charge rate, $\dot{m}_{gc}$, and/or the discharge rate, $m_{gd}$, can b·

considered constant over the given time step, $\Delta t$.

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

Combination of the above assumptions with the conservation equations yields

straighforwardly after integration to the following governing equation for

the VPA:

$$\tanh^{-1}\left\{\frac{2cT_2 + b}{\sqrt{b^2 - 4ac}}\right\} = \tanh^{-1}\left\{\frac{2cT_1 + b}{\sqrt{b^2 - 4ac}}\right\} - \frac{\sqrt{b^2 - 4ac}}{2c_p}\left\{\ln\frac{(\dot{m}_{gc} - \dot{m}_{gd})\Delta t + m_{f_0}}{m_{f_0}}\right\} \tag{2-6}$$

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:

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

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,

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

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:

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

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(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:

$$\Delta_{AVG} = I_1 - I_2$$

$$\Delta_{TAR} = I_1 - I_{TAR}$$

$$(2-13)$$

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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, $\Delta_{chng}$, is calculated based on the difference $\Delta_{avg}$.

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, $\Delta_{chng}$, is recalculated based on the difference from target, i.e., $\Delta_{tar}$.

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, $\Delta_{chng}$ based on $\Delta_{avg}$.

8. If $\Delta_{avg} < 0$ and $\Delta_{tar} < 0$, but $I_1 < 0.15$, $\Delta_{chng}$ is based on $\Delta_{tar}$

9. If $\Delta_{avg} < 0$ but $\Delta_{tar} > 0$, $\Delta$chng = 0.

10. If simultaneously with any of the above calculated HFB changes, $\Delta_{chng}$, 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 $\Delta_{chng}$, 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

contac' with the high potential mills were planned. However, due to the con-

fidential 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 th-t 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

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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

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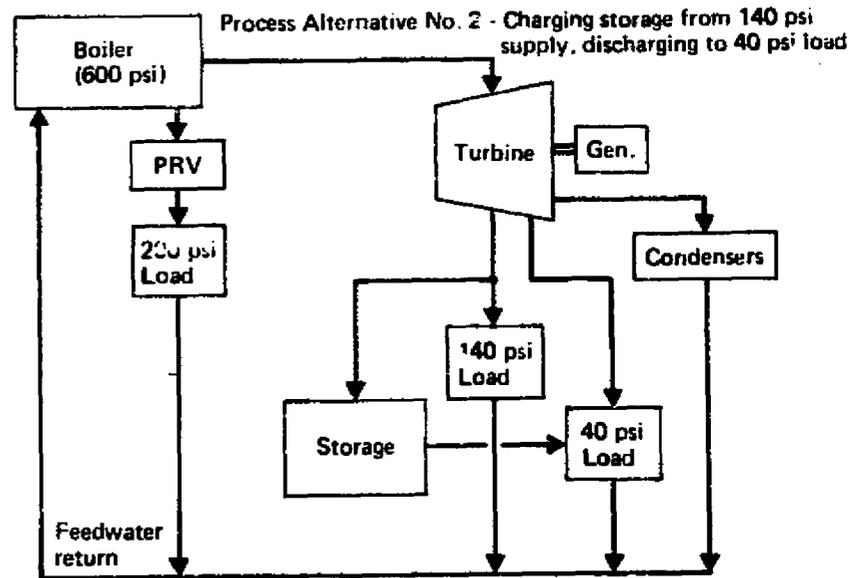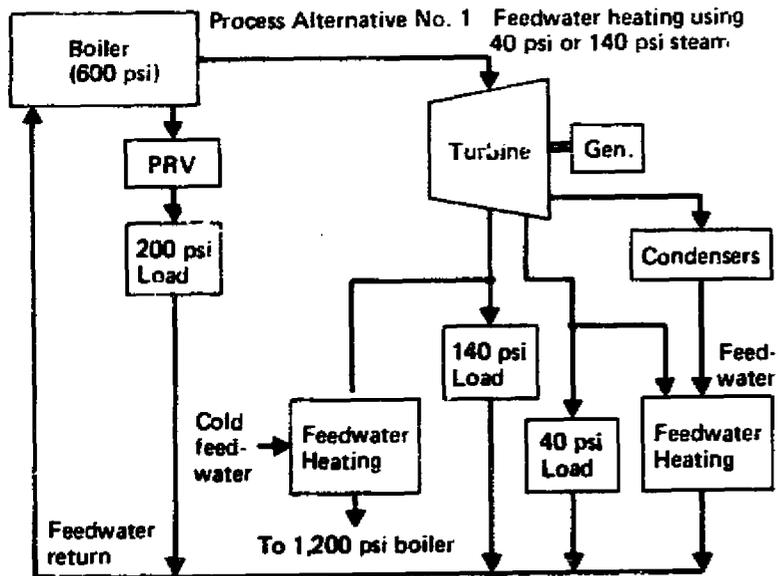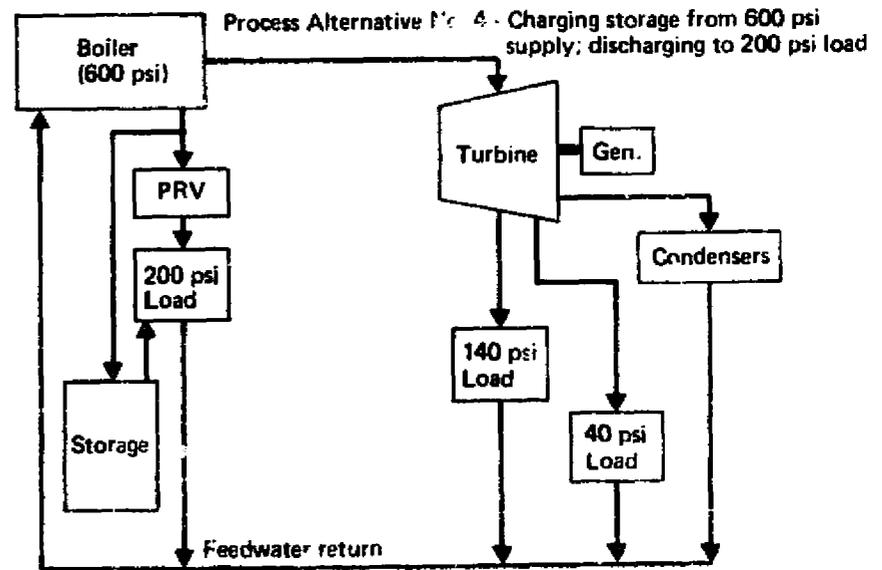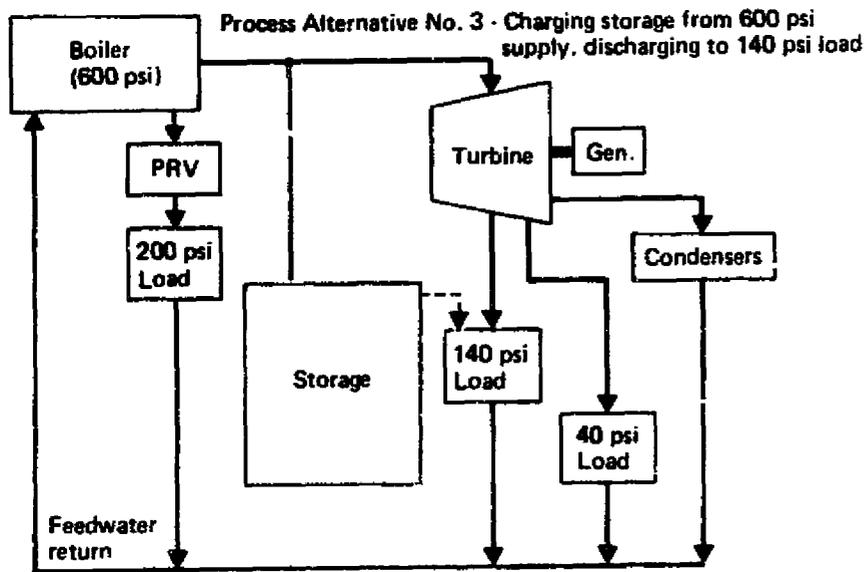
*Figure 3-1. Potential Applications of TES to Longview Mill*

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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<br>JPL - sand and iron ingots | Current technology | Conceptual design being developed | Adequate | $590^\circ$ - $650^\circ$F, can be considered for lower temperatures also, should provide thermal stratification | Adequate |
| 2. Sensible heat - rock/oil<br>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<br>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<br>Inst. of Gas Tech. | Advanced technology | In SRE stage | Corrosion control required | Melt temp. $>400^\circ$F | Adequate |
| 6. Latent heat - metal alloys<br>U. of Delaware | Advanced technology | In SRE stage | Adequate | Melt temp. $>400^\circ$F | Adequate |
| 7. Latent heat - hydroxide<br>Comstock & Wescott | Current technology | Component testing for total energy system | Adequate | Melt temp. $>459^\circ$F | Adequate |
| 8. Latent heat - Chlorides<br>NRL | Advanced technology | In SRE stage | Corrosion control | Melt temp. $= 724^\circ$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°F).  Previous BEC TES
    work indicates a 330° - 340°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°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 anti-
cipation of the addition of another hog fuel boiler. Straight-forward modifi-
cation 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 $\times 10^3$ 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 $\Delta T$'s are shown in Figure 3-2. The $\Delta T = 85°F$ 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 $\Delta T$ to use was not exactly defined at that time. Calculation of the effective $\Delta T$ value would require the operation of a given storage system design in the plant operation program over a period of time to evaluate
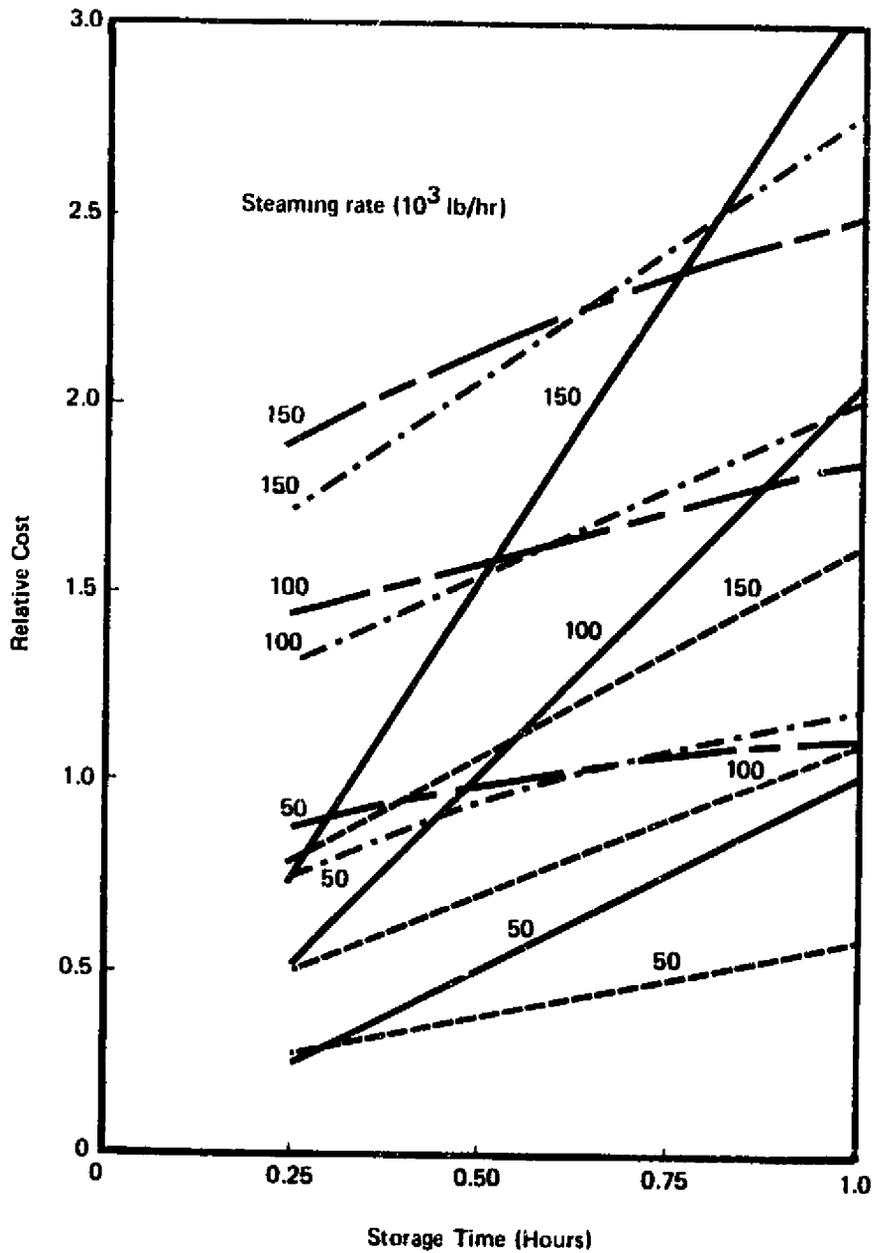
Figure 3-2. Storage Device Cost Estimates

## Table 3-2. Data Base for Initial Screening Effort

Property data

$h_{fg}$ = 920 Btu/lb

$\rho_{wf}$ = 60 lb/ft³ ⎫

$C_{pwf}$ = 0.7 Btu/lb · °F ⎬ ethylene glycol at T = 330°F

$\rho_m$ = 165 lb/ft³ ⎫

$C_{pm}$ = 0.20 Btu/lb · °F ⎬ rock

$\varepsilon$ = 0.25, void fraction in rock

P = 140 psig, design pressure

S = 13.7 x 10³ x 0.8 psi design stress ⎫ SA-516 carbon steel,

E = 0.7, weld efficiency ⎬ ASME Code, nonradiographically

$\gamma_m$ = 484 lb/ft³, metal density ⎭ inspected

$\alpha$ = L/D = 4, vessel length/diameter ratio

$\gamma_c$ = 150 lb/ft³, concrete density

$k_I$ = 0.042 Btu/ft-hr-°F, insulation conductivity

$t_w$ = 0.125 inch for liner

Cost data (preliminary)

$C_v$ = 1.00 $/lb, welded steel vessel

$C_I$ = 0.50 $/lb, liner

$C_c$ = 0.025 $/lb (100 $/cu. yd) reinforced concrete

$C_I$ = 0.25 $/ft³ (.13 $/ft² 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, ~ $\dot{m}^{0.67}$ 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.
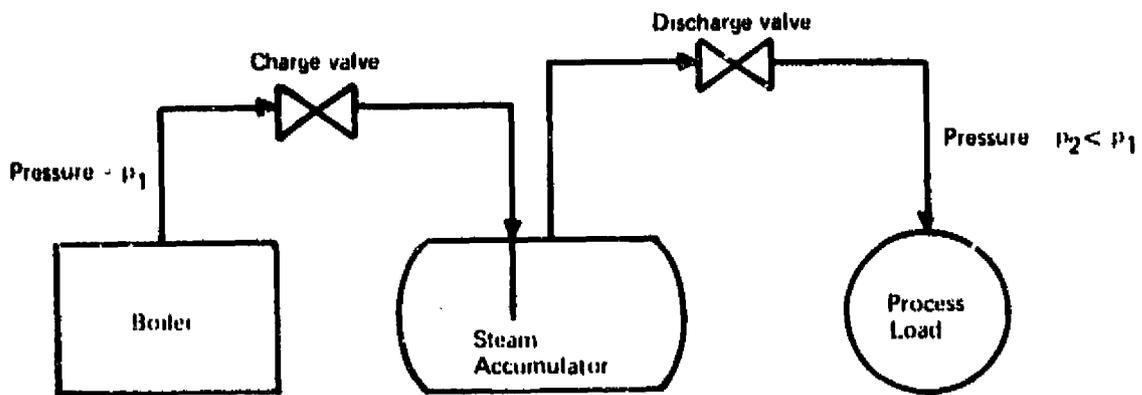
*Figure 3-3. Steam Storage with Variable Pressure Accumulator Principle*
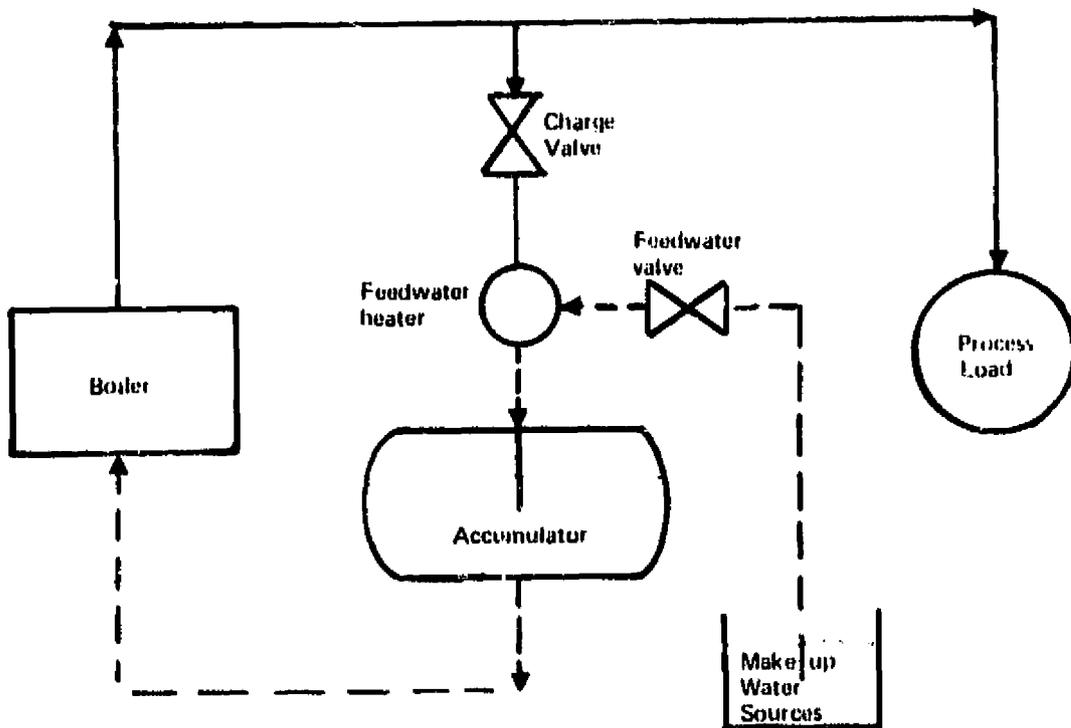


*Figure 3-4. Steam Storage with Constant Pressure Accumulator Principle*

## 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 per-
formance 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 mini-
mum 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
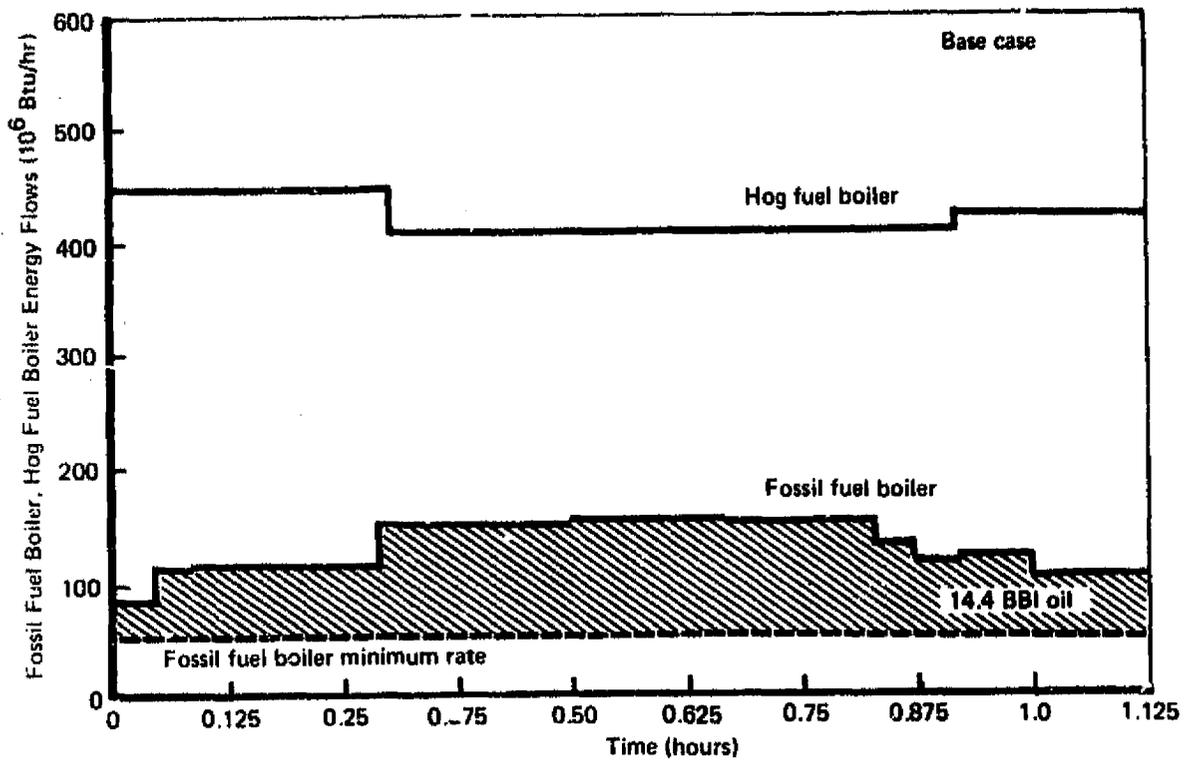
*Figure 3-5. Base Case Performance Data*
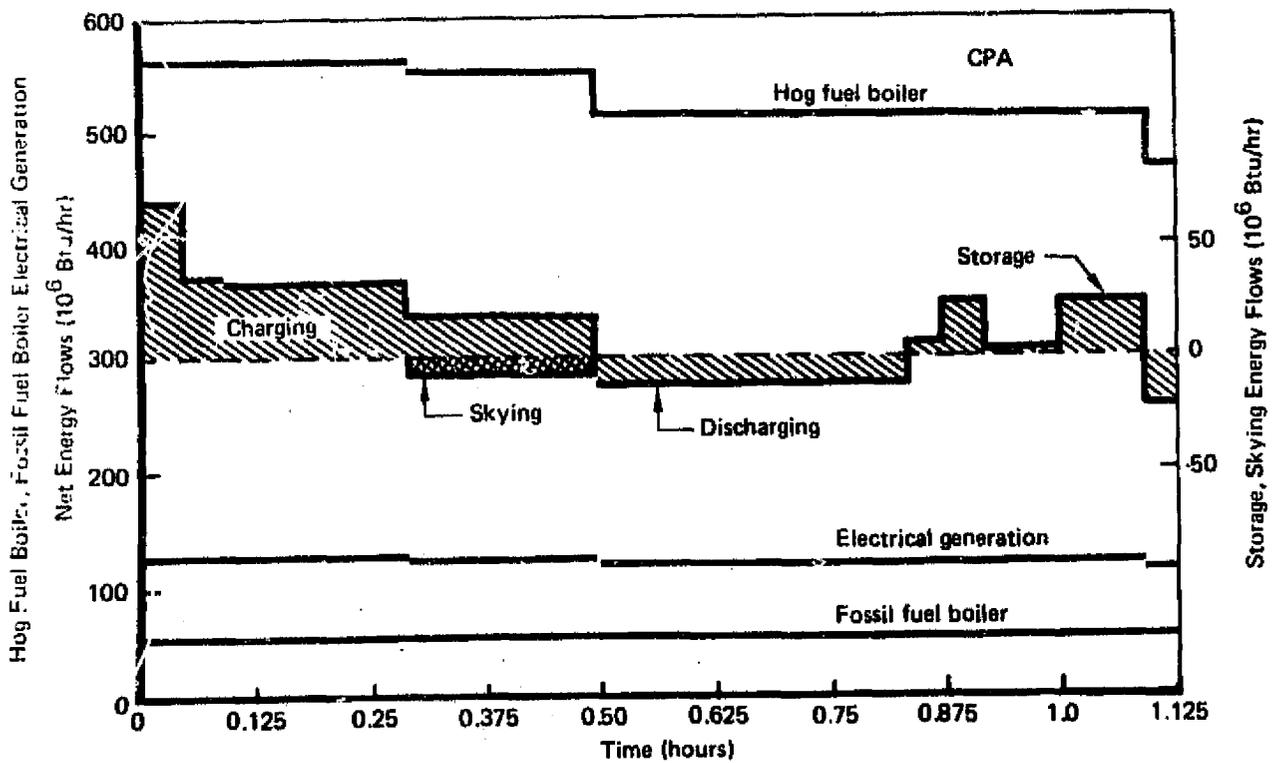


*Figure 3-6. Constant Pressure Accumulator Performance Data*
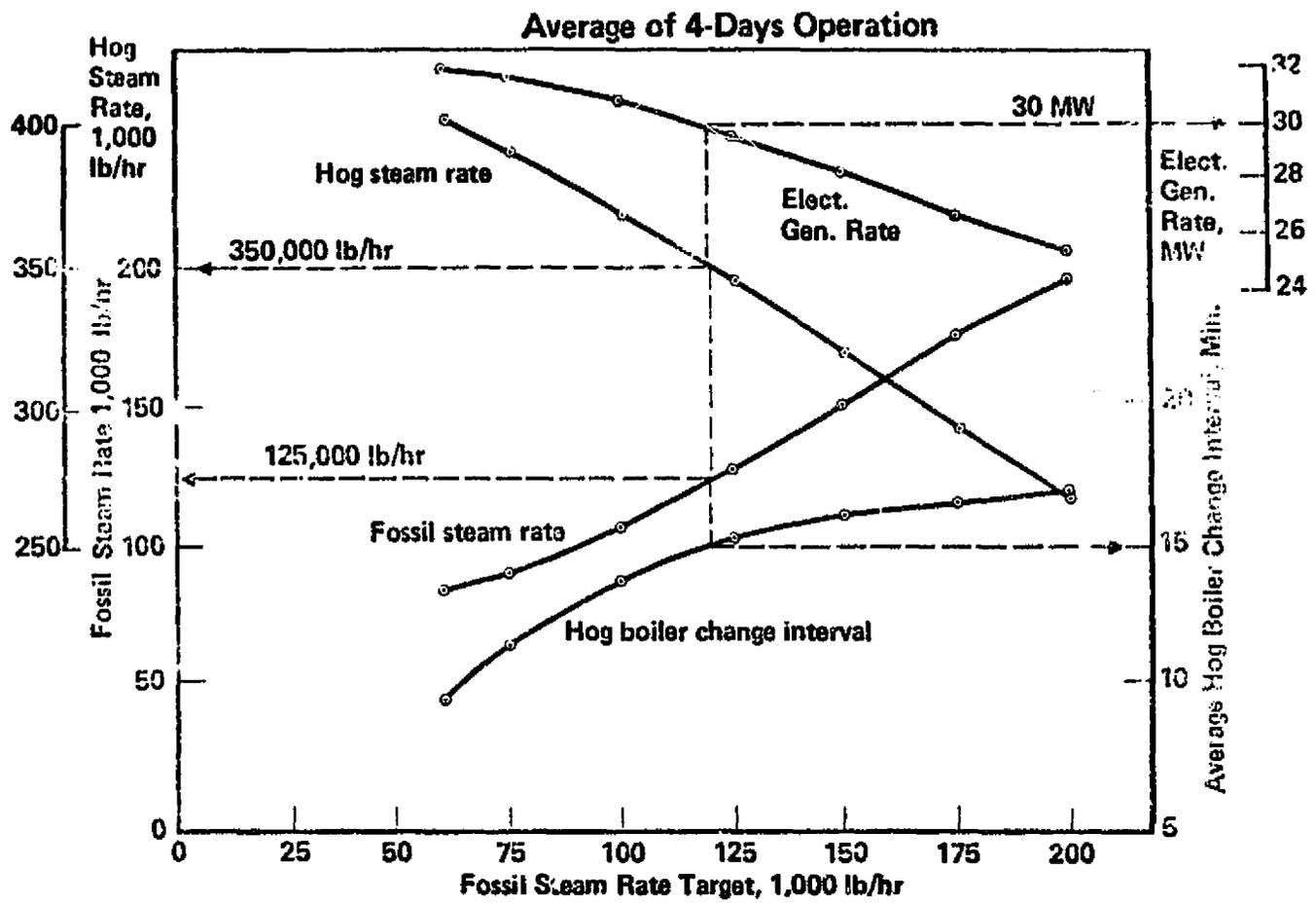
Figure 3-7. Longview Power Plant "Base" Model Performance

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, $\Delta$chng, 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

| Trade | Accumulator Type | |
| --- | --- | --- |
| | 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 steam 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.

**Average of 4-Days Operation**
**Control on Basis of Storage Inventory**
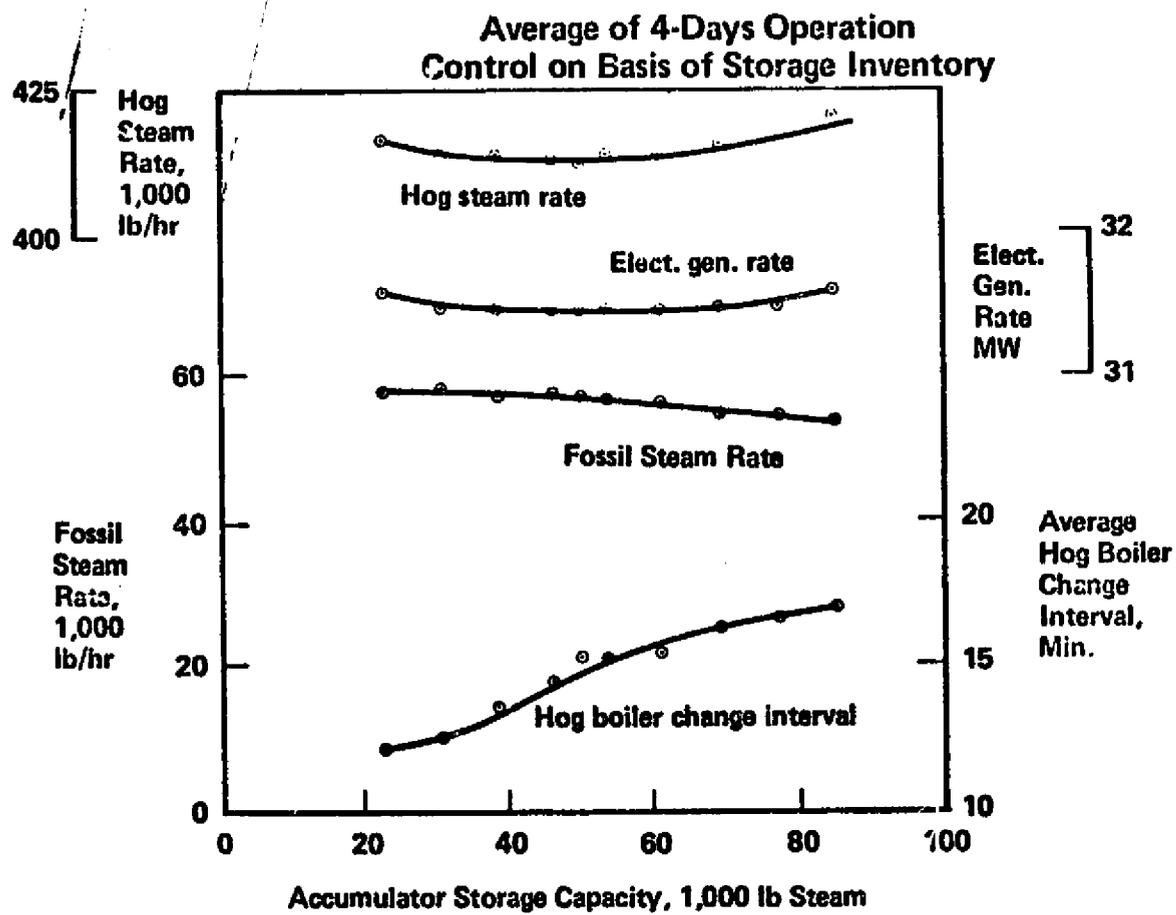
Figure 3-9. Longview Power Plant "VPA" Model Performance

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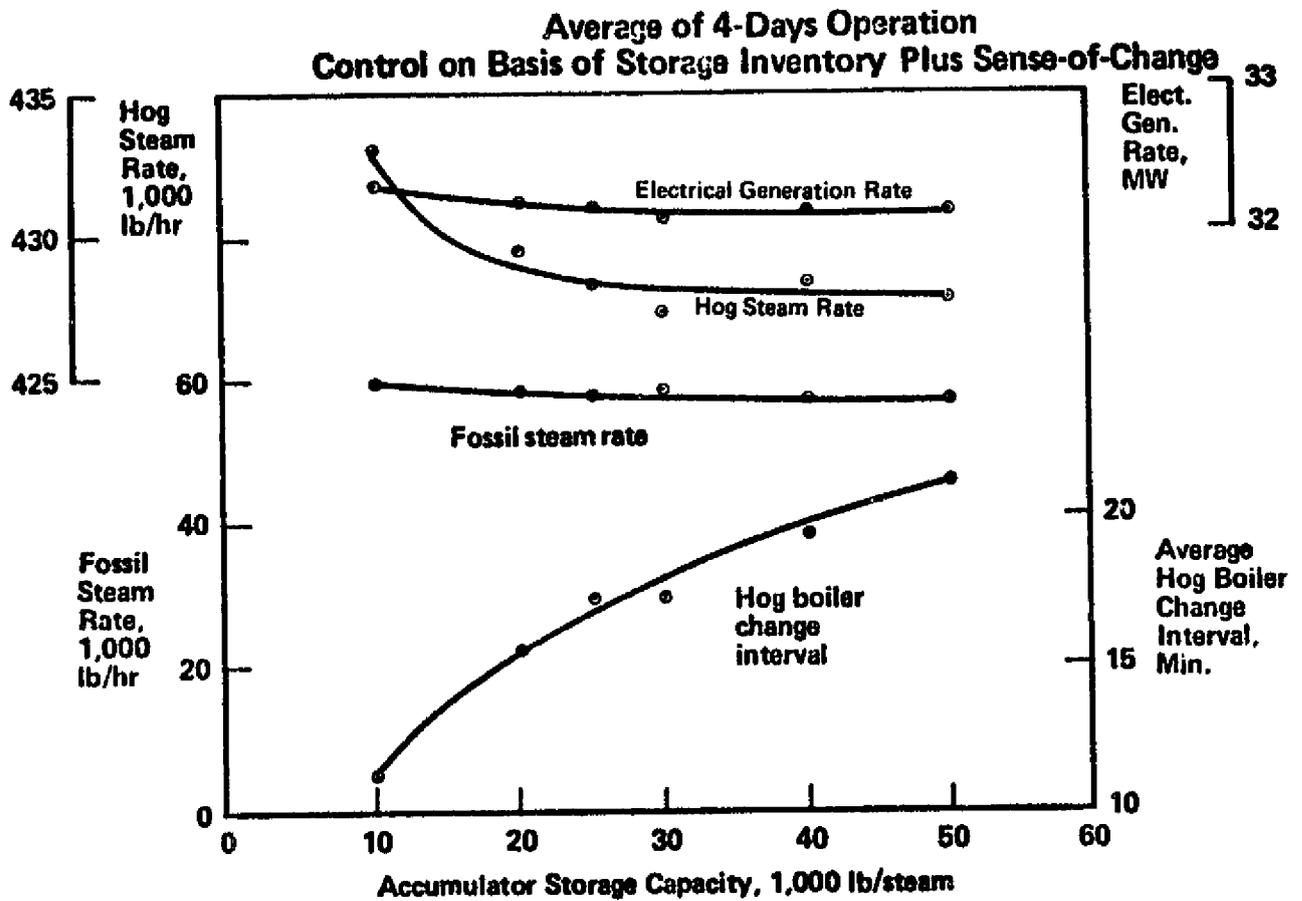
Figure 3-10.  Longview Power Plant "VPA" Model Performance
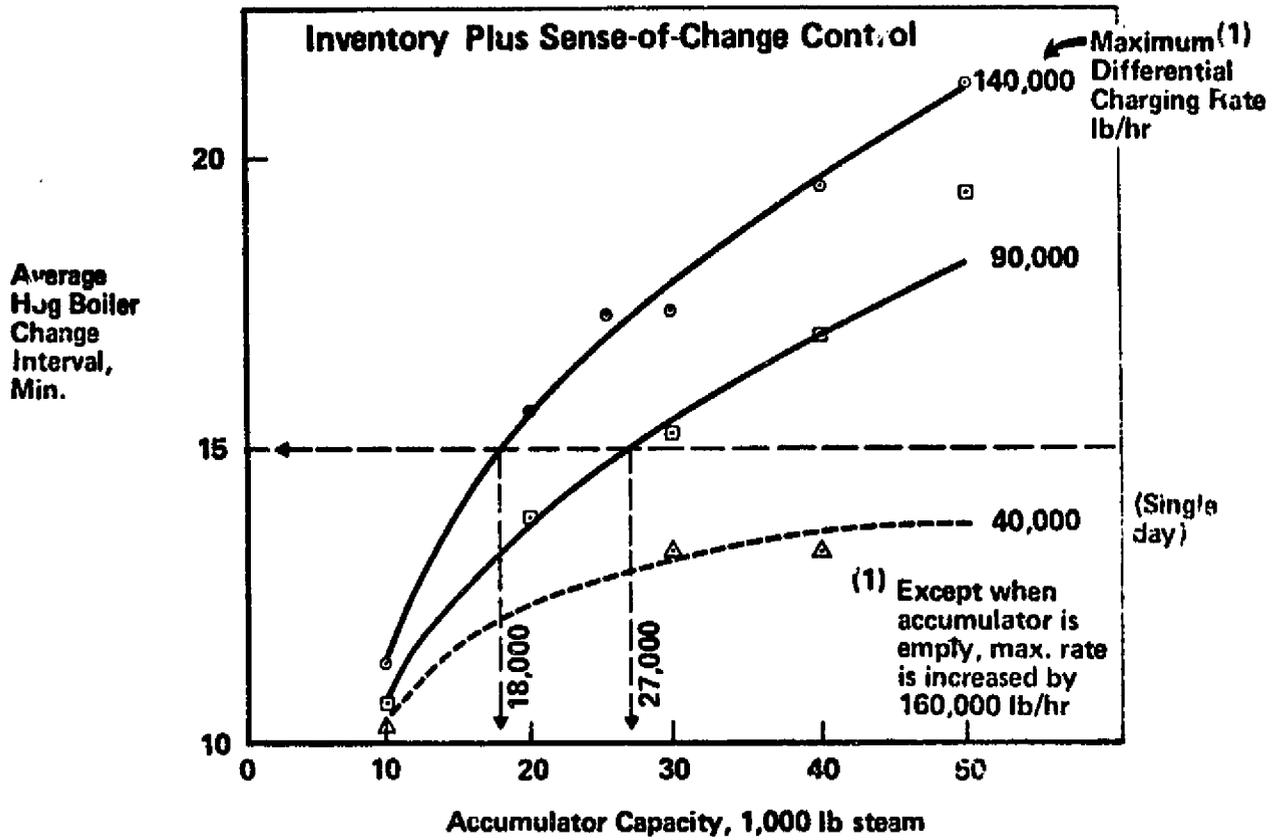
Figure 3-11. "VPA" Maximum Charge Rate/Storage Size Trades

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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

**4-Day Average Performance
Inventory Plus Sense-of-Change Control**
Maximum Differential Charging Rate Limited to 90,000 lb/hr
(Except 250,000 lb/hr when accun..ulator is empty)
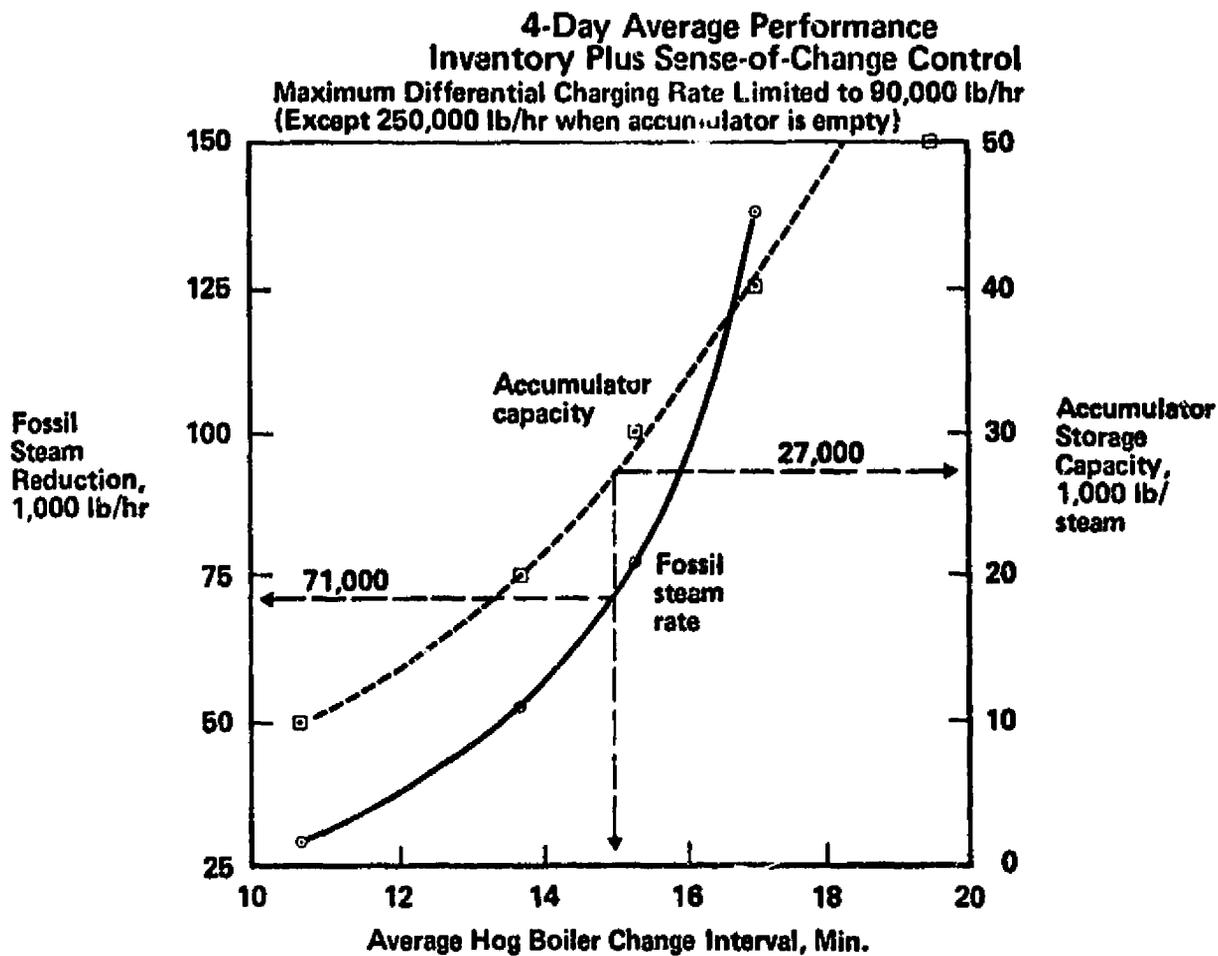
*Figure 3-13.   Fossil Steam Savings Potential with "VPA"*

### 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.
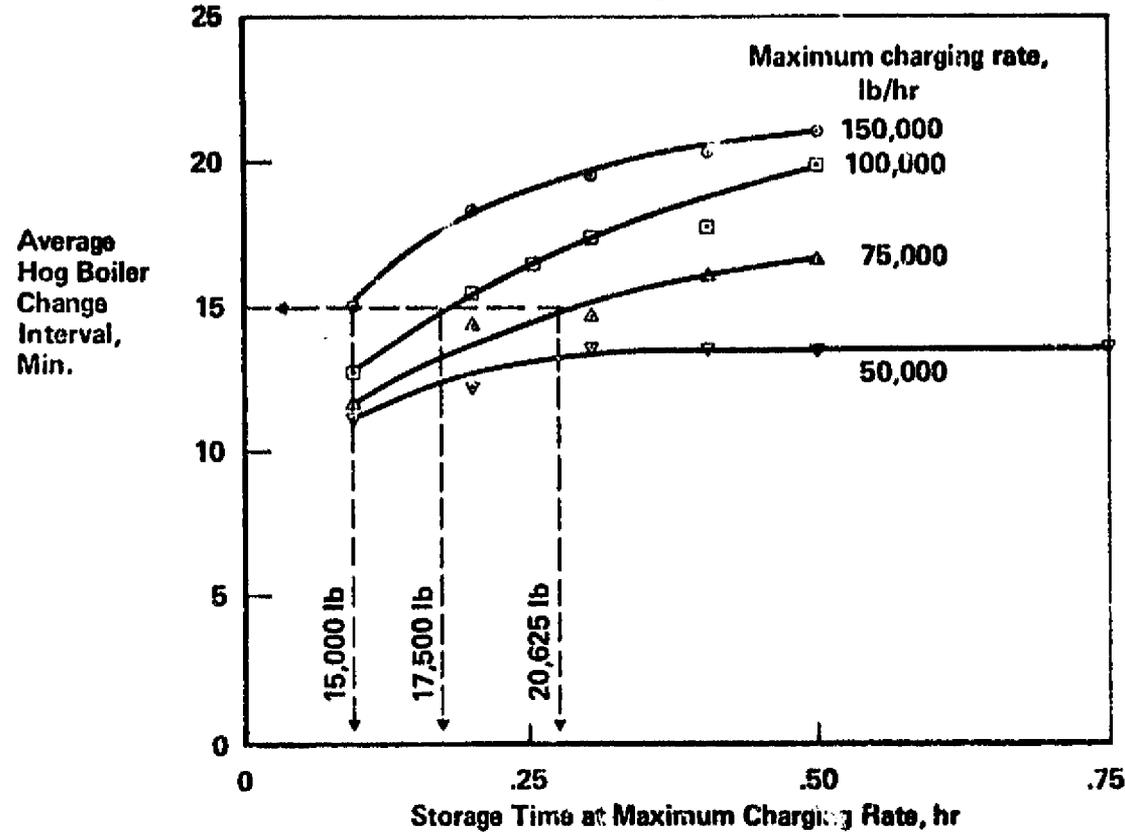
Figure 3-14. "CPA" D.A. Heater Size/Storage Size Trades
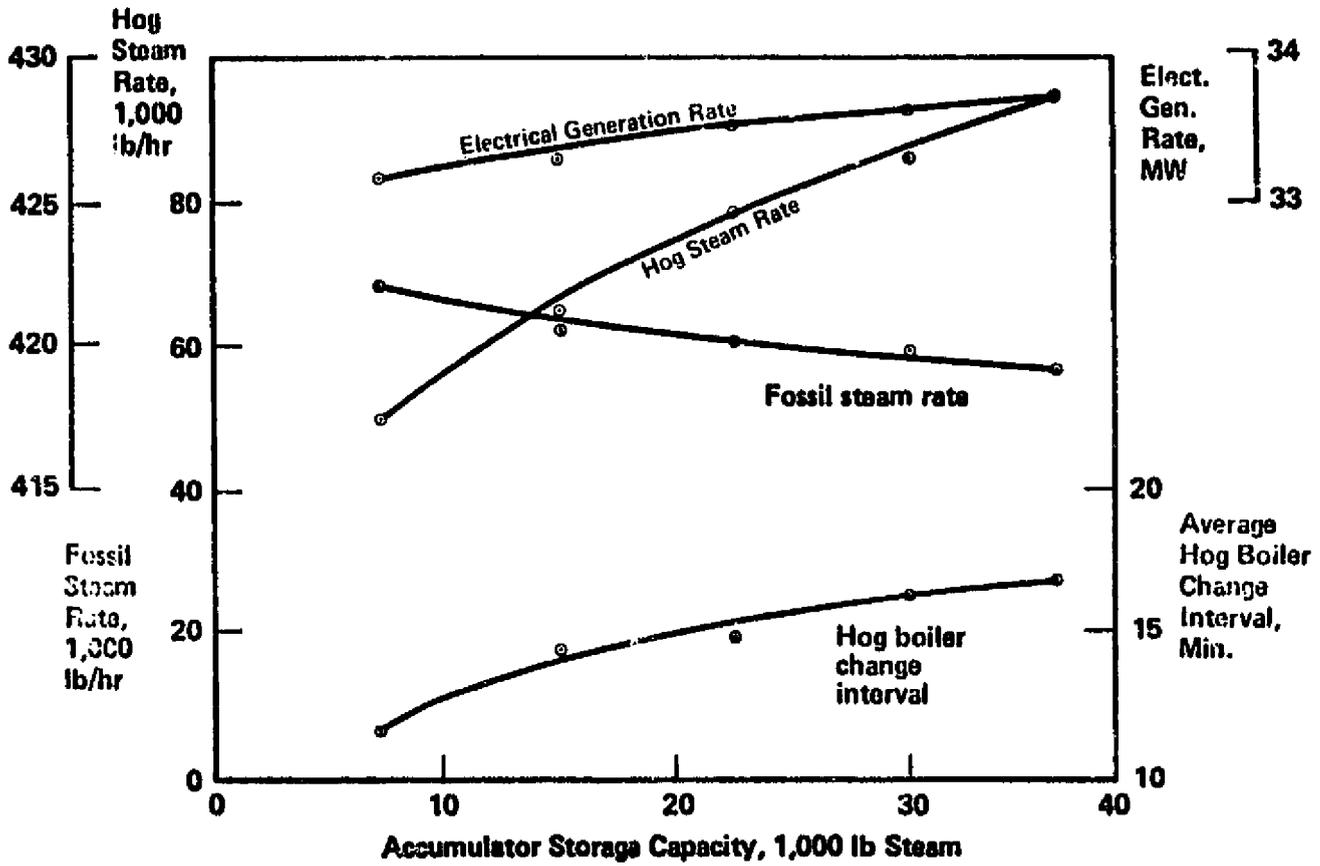
Figure 3-15. 75,000 lb/hr "CPA" Model Performance

4-Day Average Performance
Storage Inventory Plus Sense-of-Change Control
Maximum Charge Rate 75,000 lb steam/hr
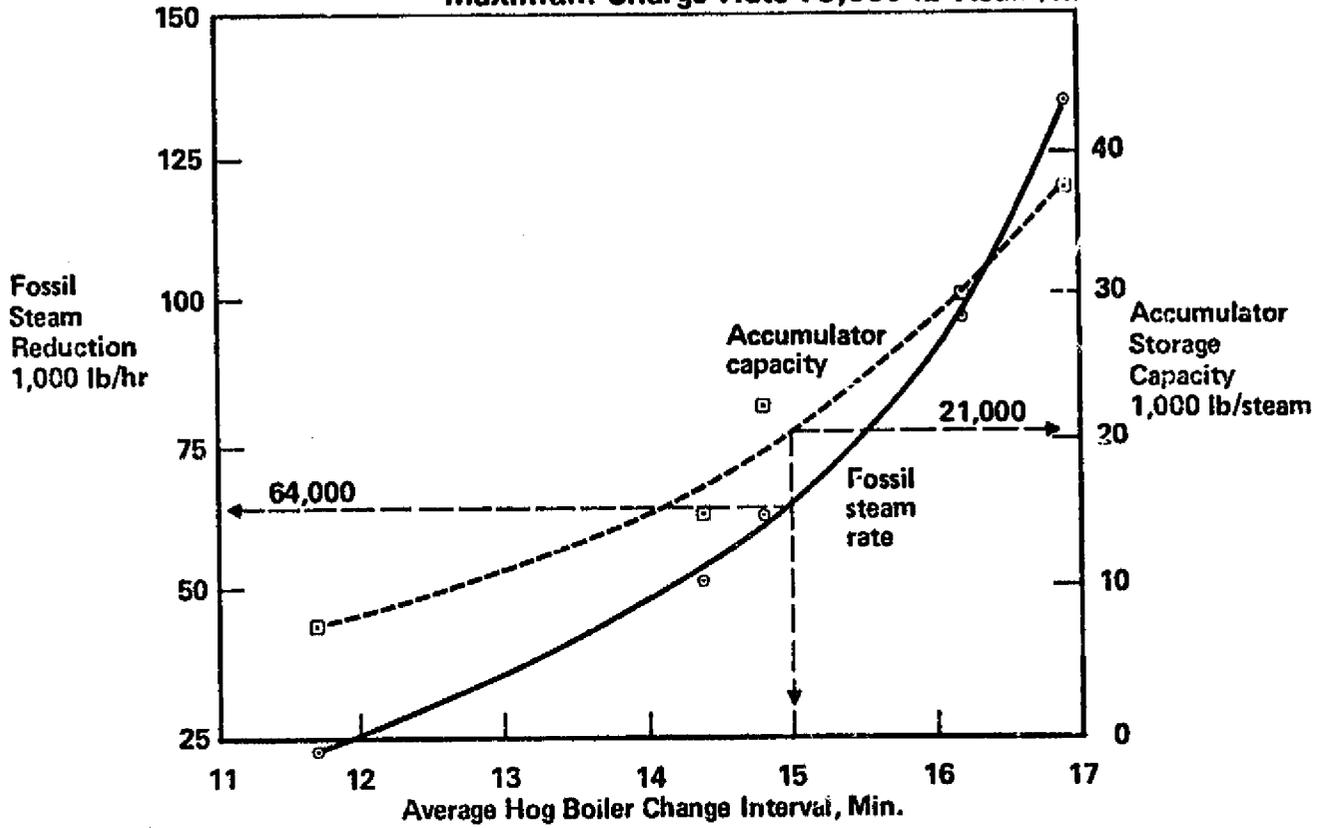
Figure 3-16.   Fossil Steam Savings Potential with "CPA"

## 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 $\tau$, hours, is given by

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

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]

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

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

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

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

$$\Delta p = p_1 - p_2$$
$$\alpha = \frac{\Delta p}{p_1} \qquad (3\text{-}3)$$
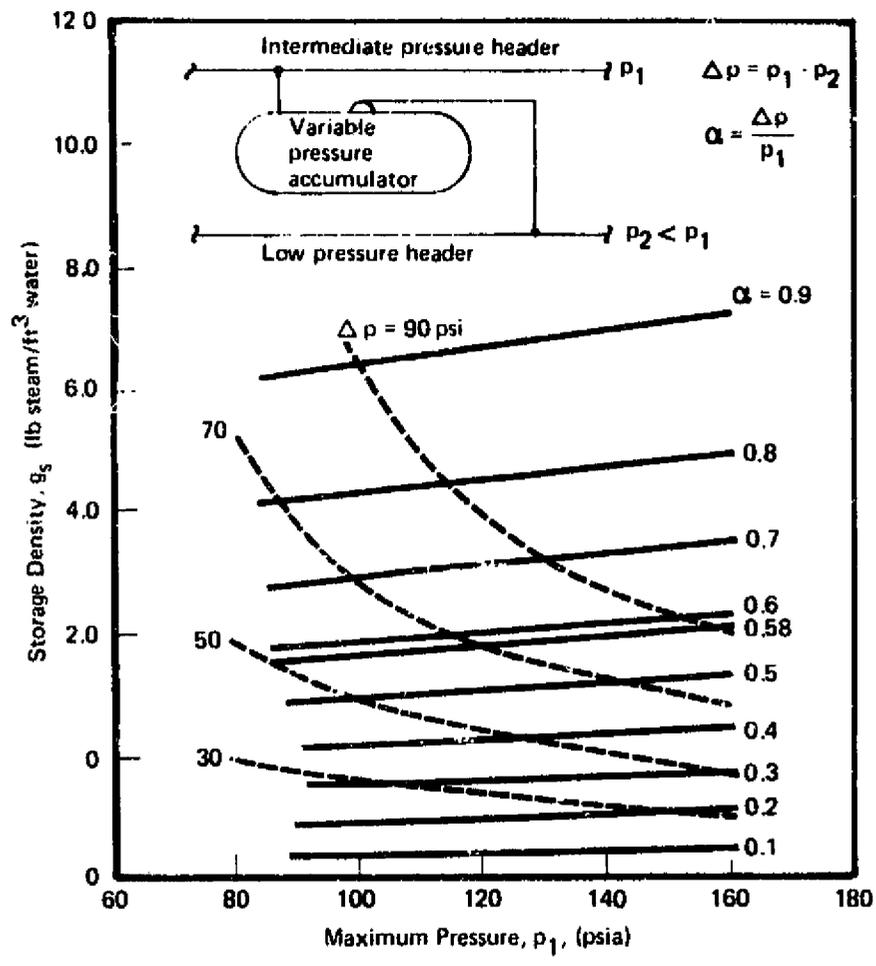
*Figure 3-17. Effect of Pressure Difference on Storage Density*

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 $\left( \Delta p = 155 - 103.5 = 51.5 \text{ psi} \right)$ yields a $g_s = 2.06$ lbm/ft$^3$, whereas a drop from 103.5 psia to 65 psia ($\Delta p = 103.5 - 65 = 38.5$ 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:

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

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

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

where D = tank inside diameter

L = length of cylindrical portion of tank

If  L = nD then

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

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

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

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

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

$$= 465 \, A_s$$

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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

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

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

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

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 $\mathcal{L}$ are given as before by

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

However, $g_s$ is given by

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

where   $\rho_w$= 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,  $\mathcal{L}$ = 0.275, $V$ = 1503 ft$^3$. Adding 10% for reserve, $V_t$ = 1503 x 1.1 = 1654 ft$^3$.

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## 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.
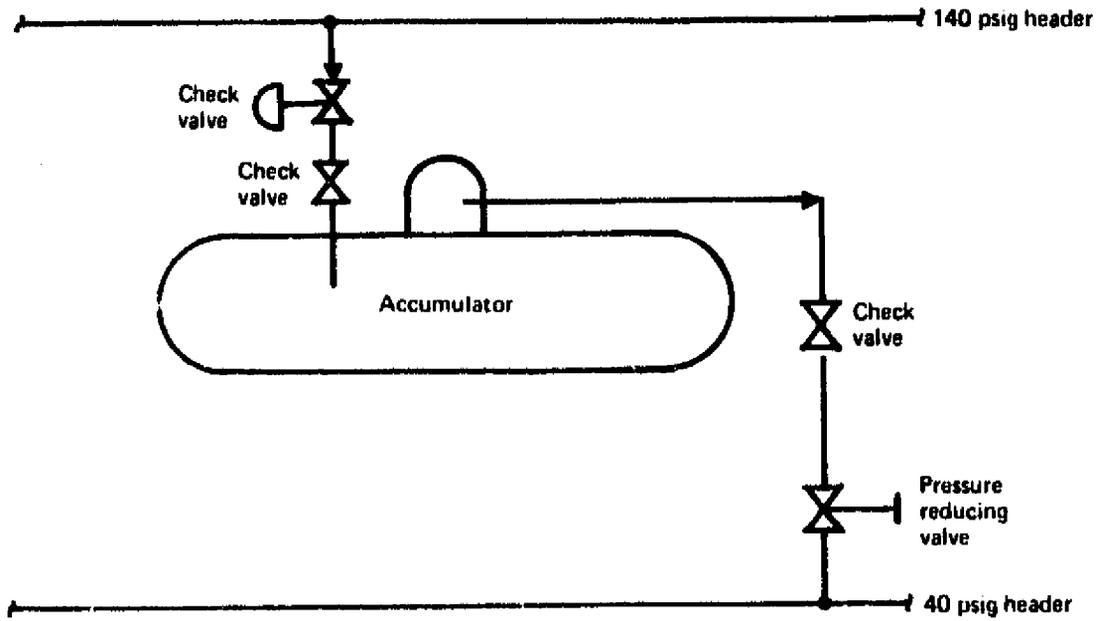
Figure 3-18. Variable Pressure Accumulator Installation Schematic
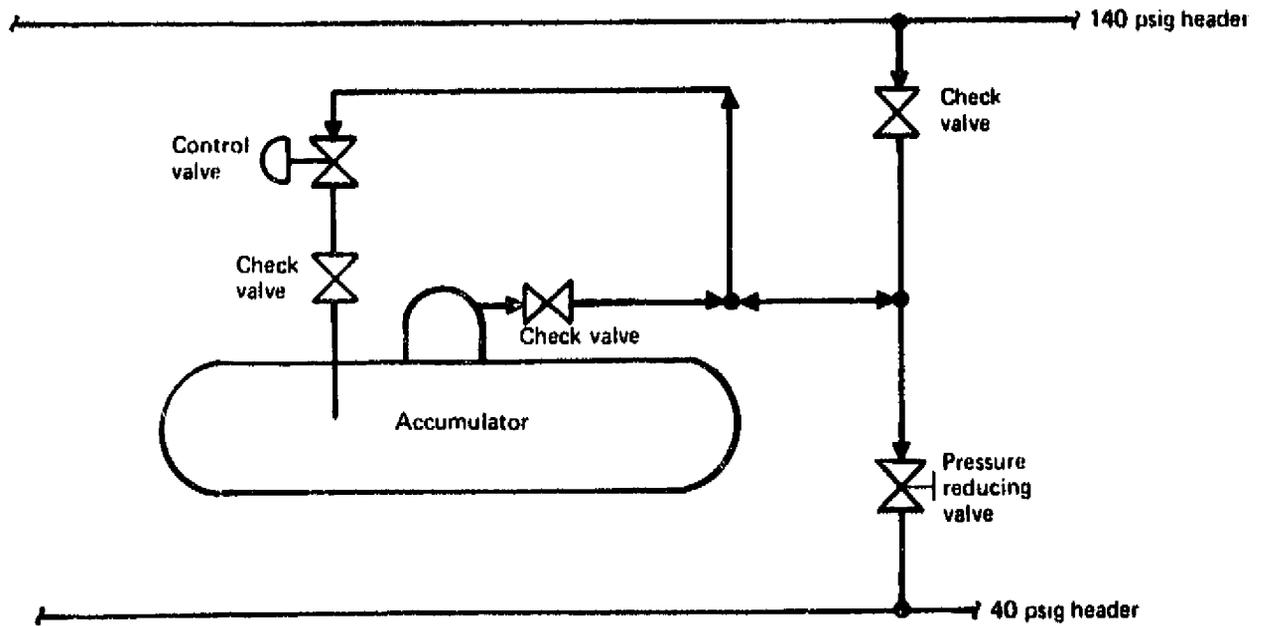


Figure 3-19. Alternate Variable Pressure Accumulator Installation Schematic

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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.
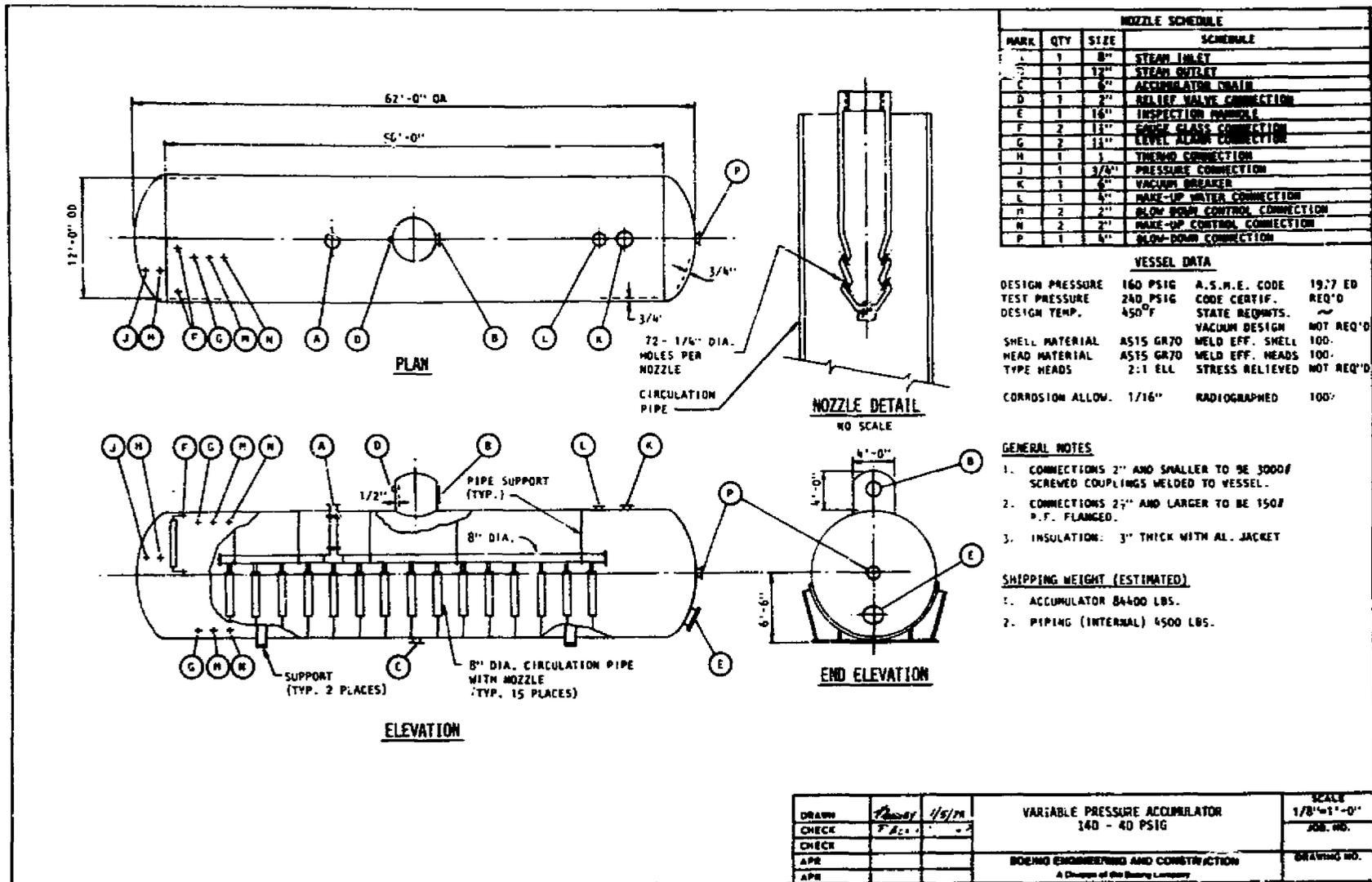
Figure 3-20. Variable Pressure Accumulator Conceptual Design

**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 |

**CRT terminal**
- Status
- Parameter modification

**Data storage**
- Control program
- Steam requirements anticipation

**Printer**
- Alarm recording
- Status records

**Mini-Computer**

**Process measurements**
- Header pressures
- Boiler flows
- Condenser flows
- Accumulator state-of-charge
- Accumulator flows
- Electrical generation

**Setpoint controls**
- HFB firing rate
- Accumulator flow
- Condenser flow

**Existing Analog Control System**

New controllers, indicators, recorders

CRT terminal

Printer

Mini-computer

Existing control rack

*Figure 3-21.   Control System Conceptual Design*

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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.

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*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

**High pressure header**

**T**

**Intermediate pressure header**

Adjust charge
rate to maintain
intermediate
pressure ——

**Hog
fuel
boiler**

Storage
inventory

Adjust HFB
steam rate to
maintain
target inventory

Adjust dis-
charge rate
to maintain
low
pressure

**Low pressure header**
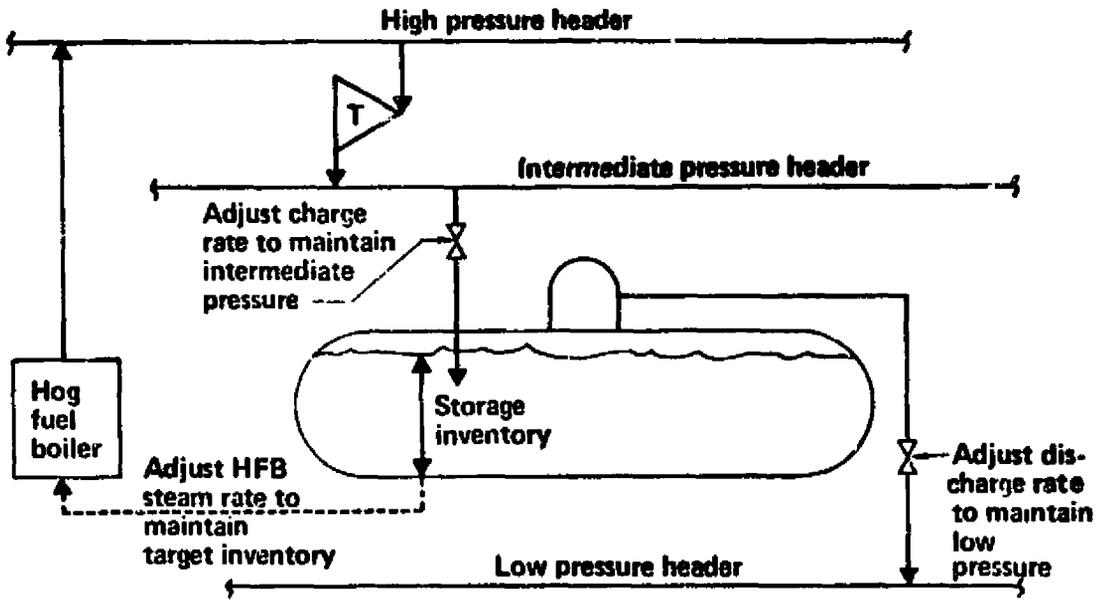
*Figure 3-22.     Variable Pressure Accumulator Control Concept*

Figure 3-23. Variable Pressure Accumulator Instrumentation
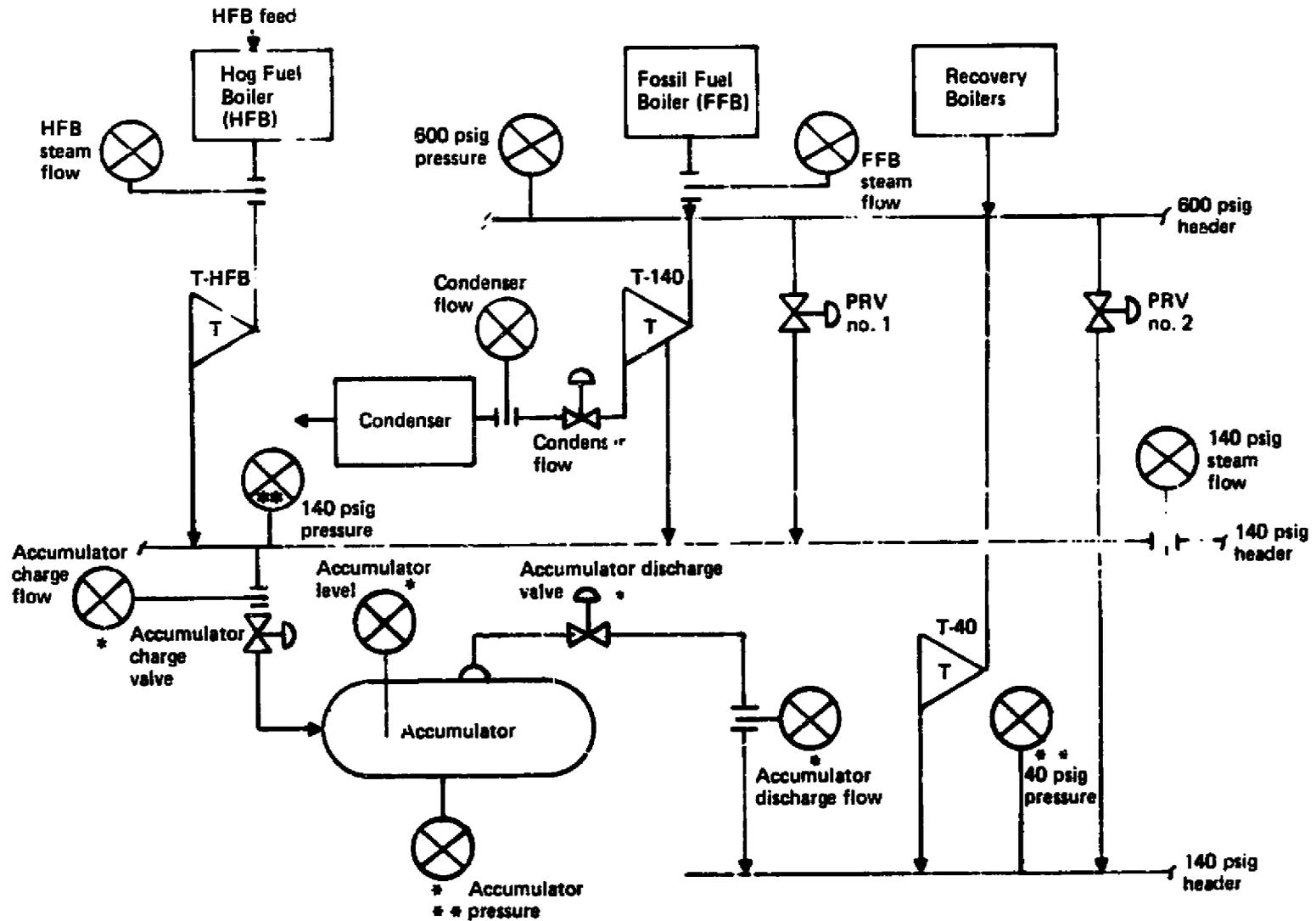
* New instrumentation/controls
** To indicator/controller on
    control panel

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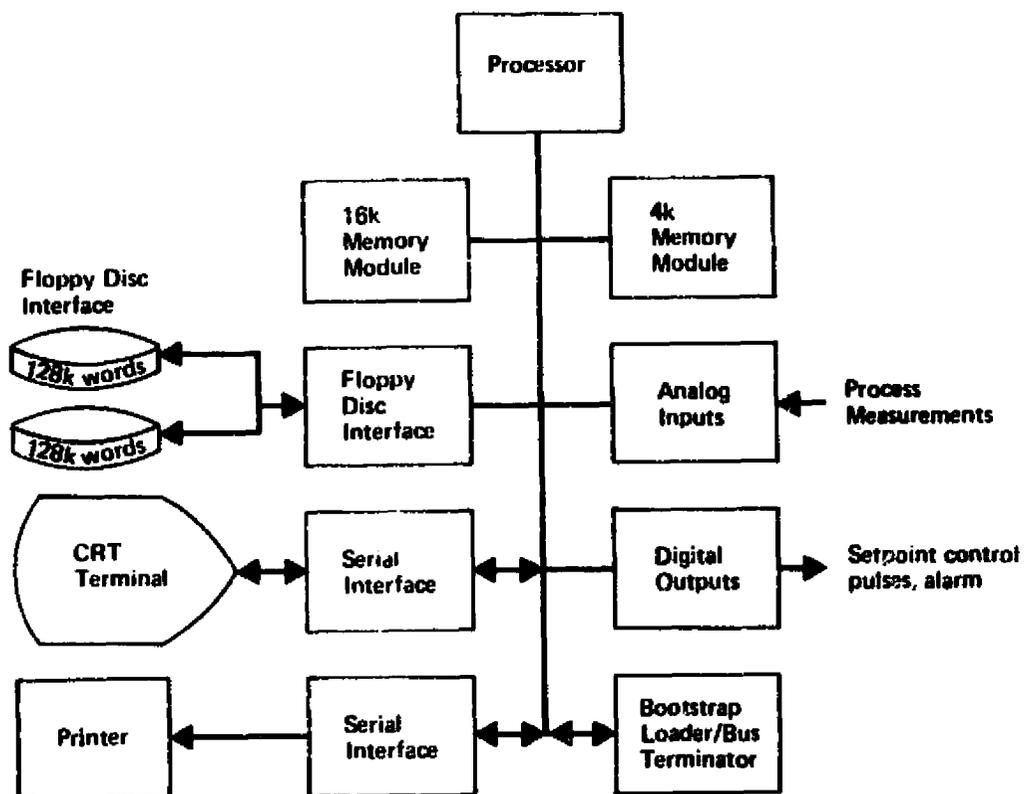
*Figure 3-24. Data Acquisition and Control Computer Configuration*

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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

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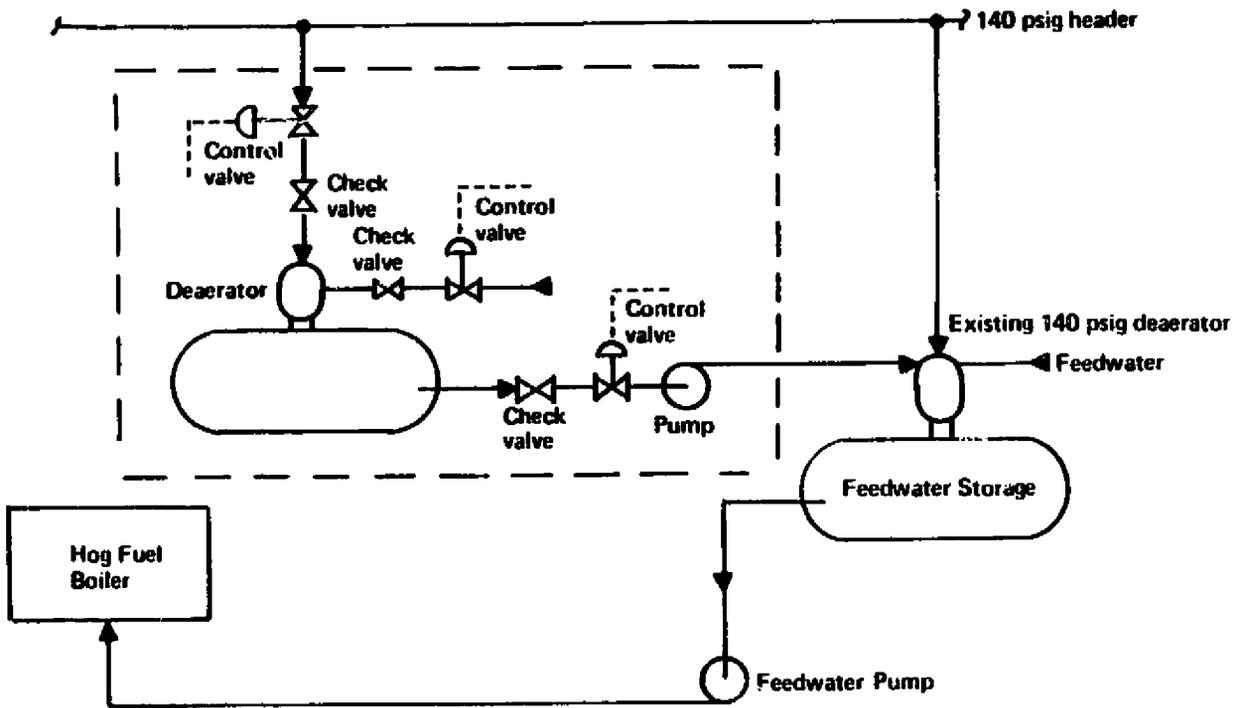
*Figure 3-25. Constant Pressure Accumulator Installation Schematic*

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PLAN

**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 | 19" | 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 | 1" | GAUGE GLASS CONN. |
| P | 2 | 1" | 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 | YES |
| TEST PRESSURE | 240 PSIG | CODE CERTIF. | REQ'D |
| DESIGN TEMP. | 450°F | STATE REQMTS. | ~ |
| | | VACUUM DESIGN | NOT REQ'D |
| SHELL MATERIAL | A515 GR70 | WELD EFF. SHELL | ... |
| 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 11200 LBS.

ELEVATION

END ELEVATION

SUPPORT
(TYP. 2 PLACES)

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

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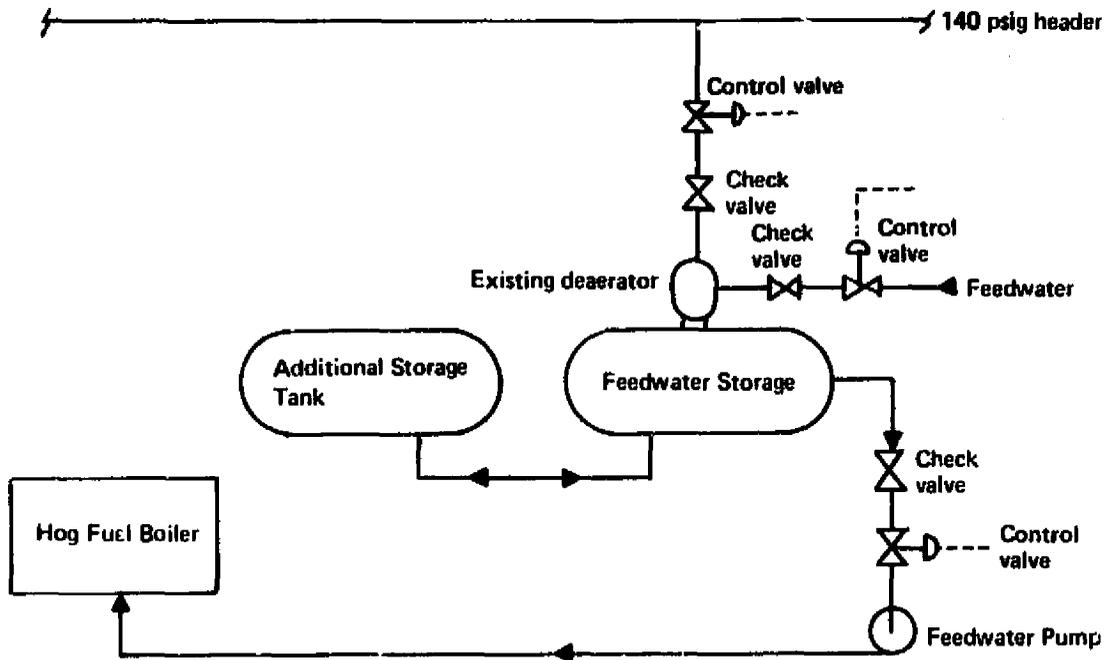
*Figure 3-27. Potential Installation CPA Schematic for Longview Application*

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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
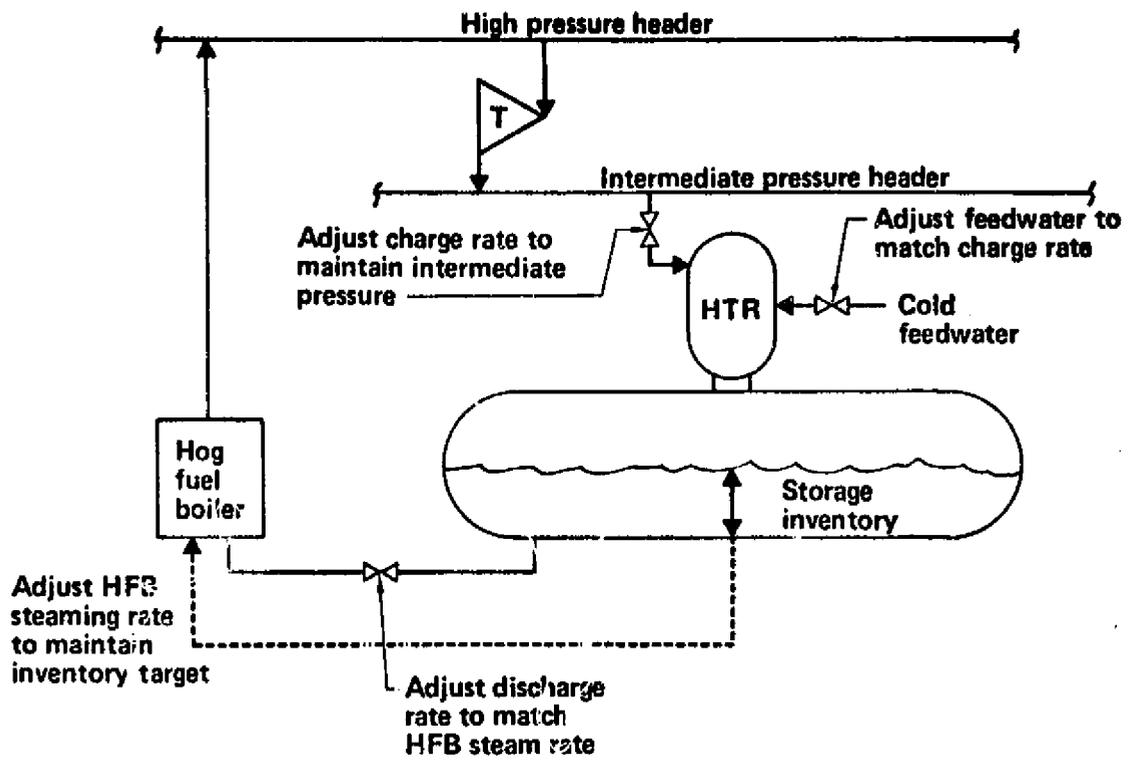
Figure 3-2. Constant Pressure Accumulator Control Concept
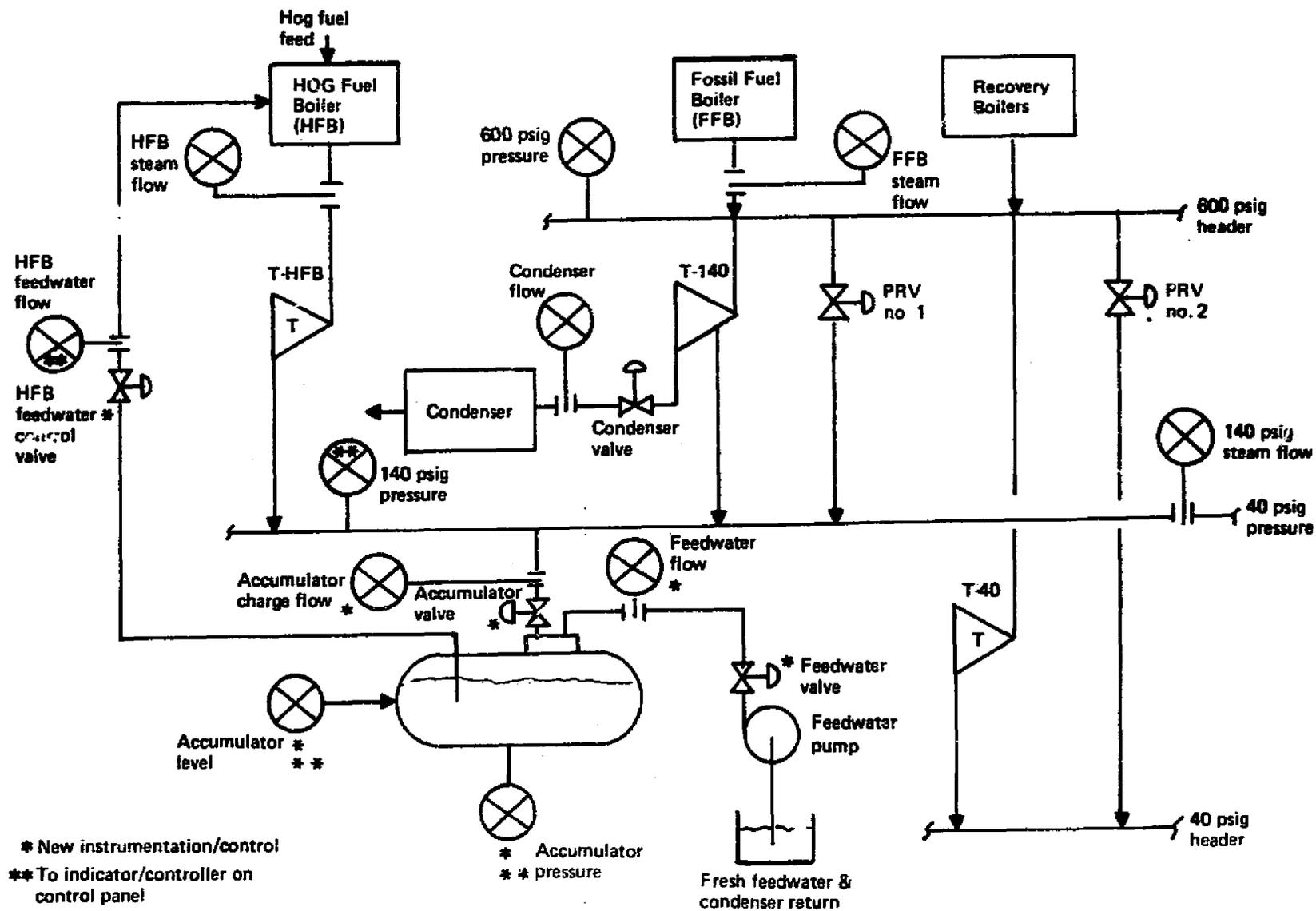
Figure 3-29.  Constant Pressure Accumulator Instrumentation

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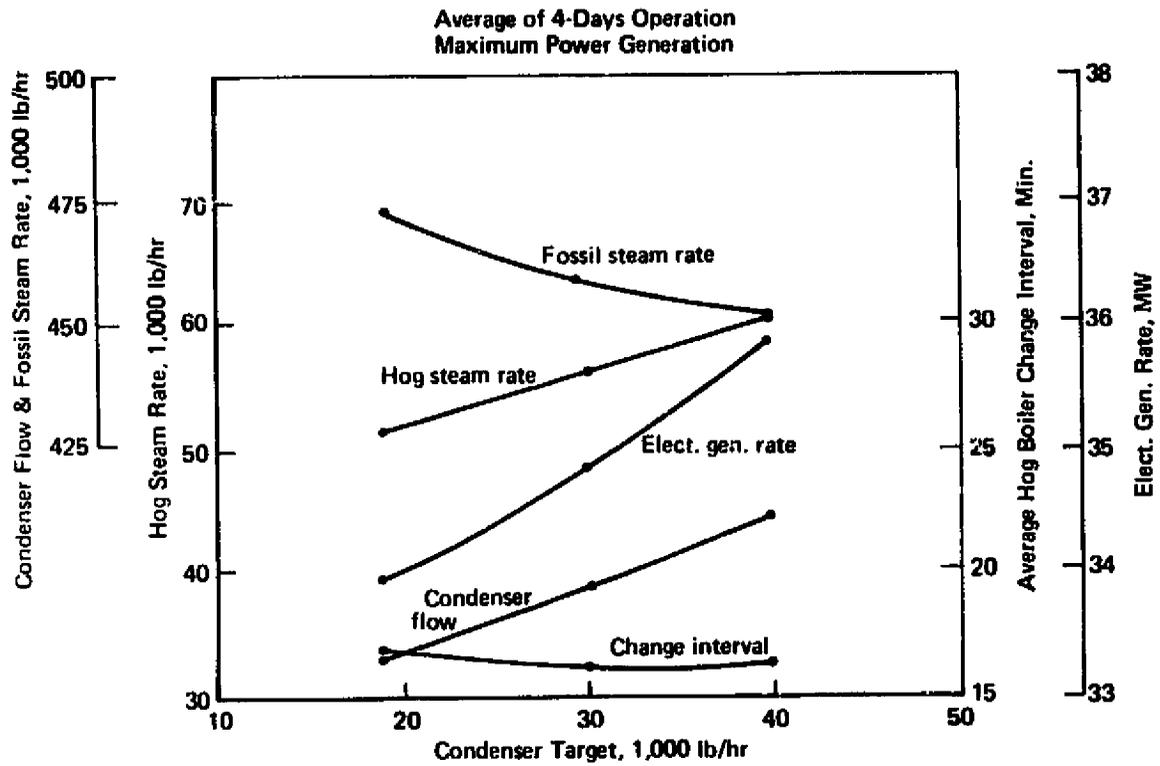
Figure 3-30. Longview Power Plant Model with Condenser Swing Smoothing - Process Analysis

## Minimum Power Generation
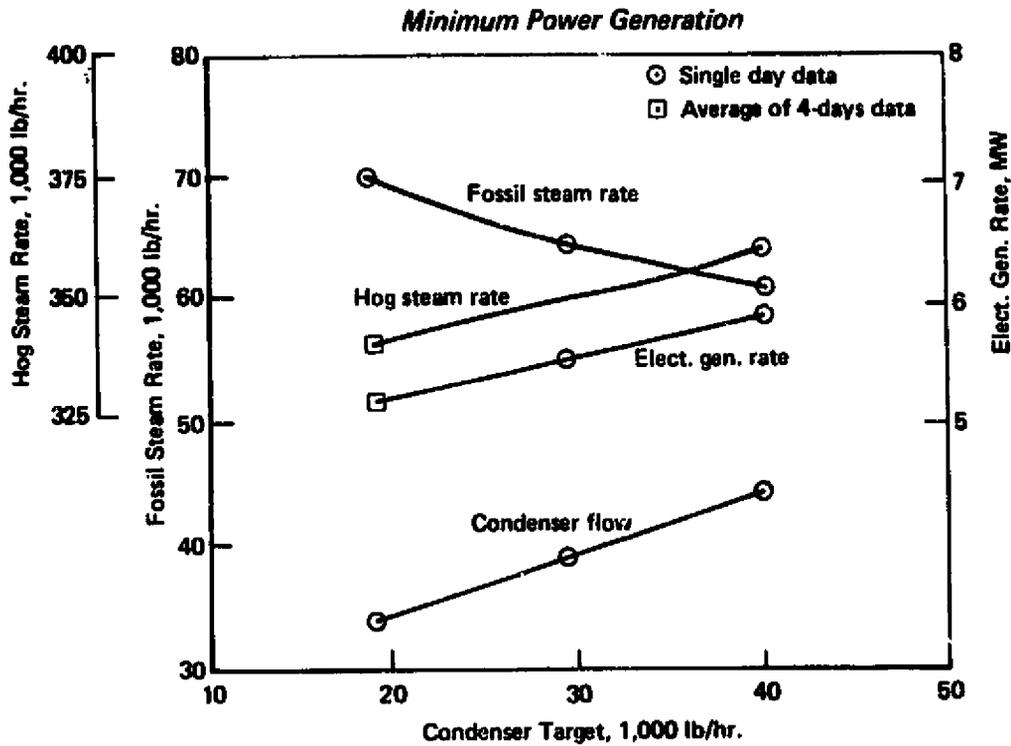


Figure 3-31. Longview Power Plant Model with Condenser Swing Smoothing
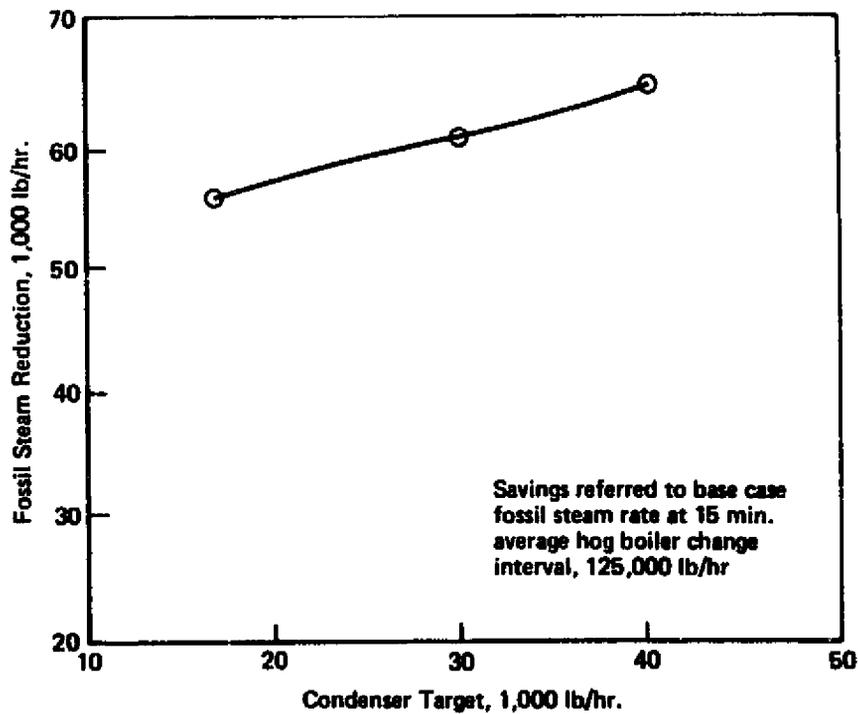


Figure 3-32. Fossil Steam Savings Potential with Condenser Swing Smoothing
- 4-Day Average Performance

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## Optimum Seasonal Turbine Operation Strategy

- Fossil fuel cost $15/bbl
- Electricity value
  $16/MW-hr (winter)
  $1.30/MW-hr (summer)

*Annual Operating Savings, $1,000* (y-axis)

*Hog Fuel Cost, $/BDT* (x-axis)
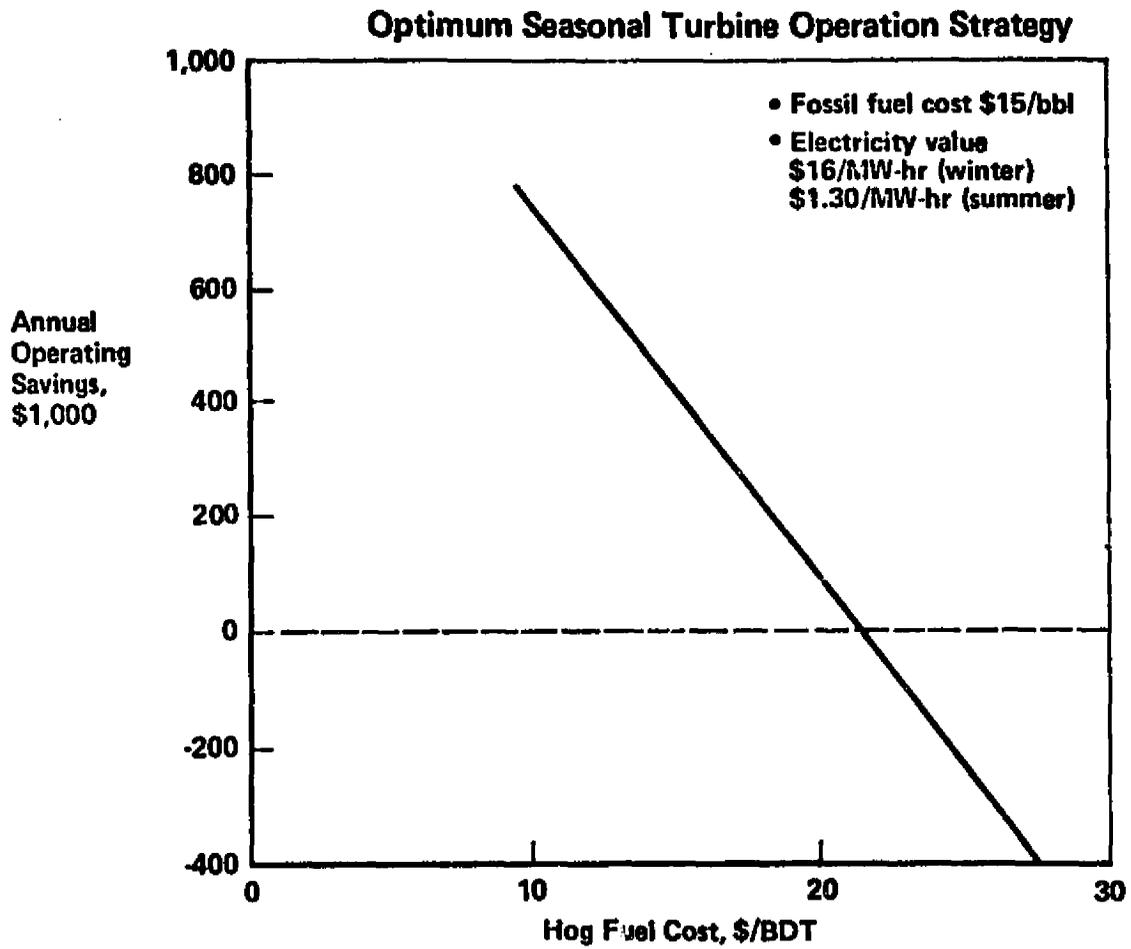
*Figure 3-33. Condenser Swing Smoothing Savings*

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 fue., 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

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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,

$$R = C_F \frac{Q}{E_F} + C_pE - C_H \left( \frac{Q}{E_H} + \frac{3.412\ E}{E_H E_p f} \right) - (O\&M)$$

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

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$E_F$, $E_H$ = 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

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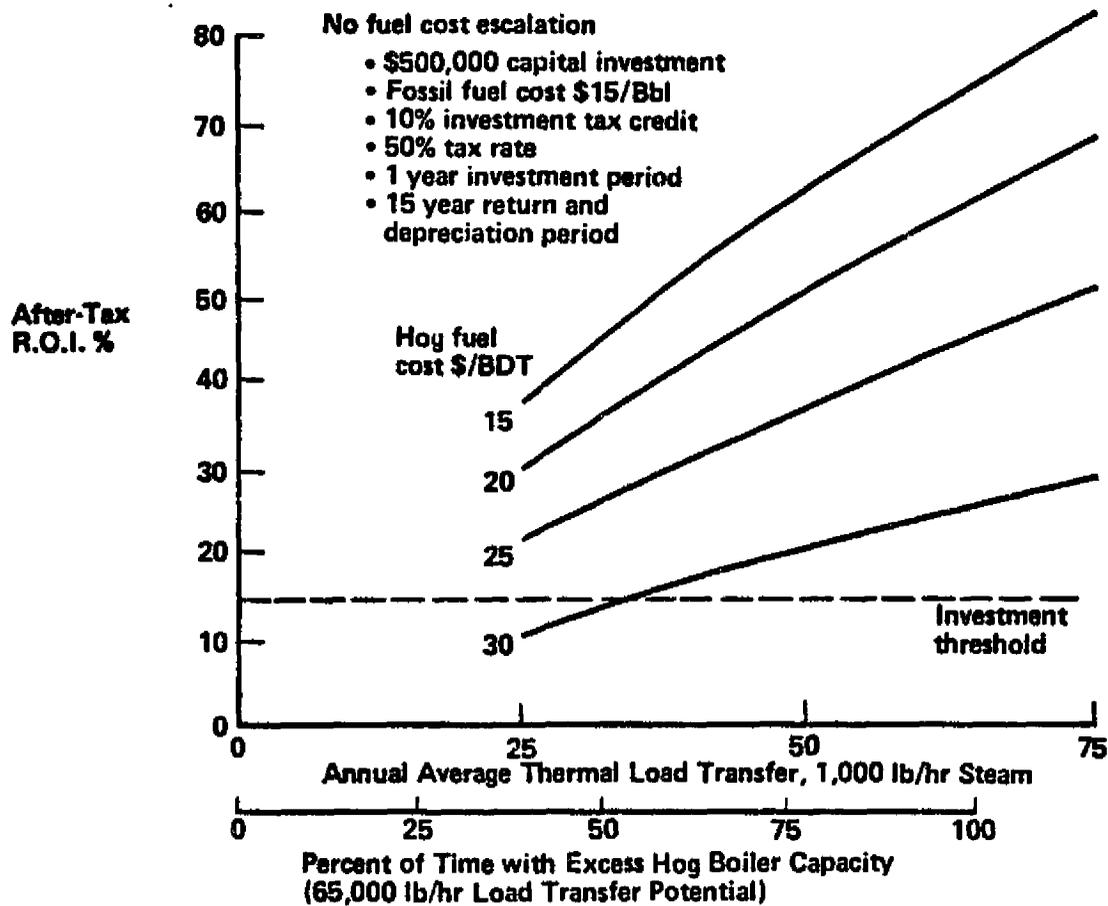
Figure 5-1. Return on Investment — No Incremental Electrical Generation

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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 not 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.

| Program Element | Activity | Year 1 | Year 2 | Year 3 |
|---|---|---|---|---|
| D.O.E. Demonstration Program | System Design | Performance analysis — Data analysis / Design review — Demonstration system specification & preliminary demonstration plan | | |
| | Fabrication/Procurement | Industrial participant commitment △ — Accumulator on-dock ▽ — Computer on-dock ▽ — Control system checkout complete ▽ — Shop drawings release △ — △ Start coding | | |
| | Installation & Checkout | Installation checkout ▽ — ▽ Demonstration system checkout complete — A&E complete △ | | |
| | Performance Demonstration | | Demonstration plan update ▽ — Winter performance data ▽ | Summer performance data ▽ |
| Industrial Implementation | Industry Briefings | Schedule & agenda ▽ — Industry expressions of interest ▽ — △ Market assessment — Industry briefings △----△ | | |
| | Selected Plants Economic Analysis & Preliminary Design | Data analysis ▽ — Performance analysis ▽ — Preliminary design & economic analysis (typ.) ▽ — Plant no. 1 — Plant no. 2 — Plant no. 3 — Plant no. 4 — Plant no. 5 | | |
| | Industrial Procurement | | Industry go-ahead decision ▽ — Contract award ▽ — Specification release | First commercial installation on-line ▽ |

*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

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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

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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:

o   The demonstration program will be ready for implementation, with system and hardware specifications in hand and refined cost estimates available.

o   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.

o   Approximately five candidates for early implementation following the demonstration program will have been identified.

| Program Element | Tasks | Months | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 |
| Demo. System Design | Program Reviews | | System requirements ▽ | | Concept selection & sizing ▽ | Preliminary design ▽ | | Implementation plan ▽ |
| | Process Analysis System Engineering | Data analysis complete ▽ | | Model update ▽ complete | Performance trades complete ▽ | | Implementation cost estimate complete ▽ | System specification & demonstration ▽ plan complete ▽ |
| | Storage System Design | | | | | Storage P.D. complete ▽ | Storage specifications complete ▽ | |
| | Control System Design | | | | | Controls P.D. complete ▽ | | Controls specifications complete ▽ |
| | Installation Design | | | | | Plant layout complete ▽ | | Interface specifications complete ▽ |
| Industry Briefings | Program Reviews | Data package ▽ | | | | Industry response ▽ | | Market assessment ▽ |
| | Planning/Scheduling | | Schedule & agenda ▽ | | | | | |
| | Industry Discussions | | Briefings to selected candidates ▽ | | | Early implementation candidates identified ▽ | | |
| | Market Assessment | | | | | | | Industry implementation projection ▽ |

*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, feed-water 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.

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## TABLE A-1  BOILER CHARACTERISTICS

| NUMER | TYPE | STEAM FLOW $10^3$ LB/HR | | | PRESSURE PSIG | TEMP °F | ENTHALPY Btu/LB |
|---|---|---|---|---|---|---|---|
| | | MAX | BASE | MIN | | | |
| 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 Recovery | 500 | 400 | 300 | " | " | " |
| 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 | | | | STEAM ENTHALPY, BTU/LB | | |
|---|---|---|---|---|---|---|---|---|
| | | MAX INLET | 140 PSIG BLEED | 40 PSIG BLEED | 2" HG CONDENSER | 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 F | FLOW $10^3$ LB/Hr | ENTHALPY Btu/LB | PRESSURE PSIG | PRESSURE 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 | #2 | HOG FUEL #11 | RED LIQUOR #1 | #2 | #6 | FOSSIL FUEL #7 | #8 | #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

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# TABLE A-8 - MONTHLY BOILER STEAM FLOW
## (WEIGHT UNITS DATA)
### MONTHLY BOILER STEAM FLOW, $10^3$ LB

| MONTH | ELECTRIC #1 | #2 | HOG FUEL #11 | RED LIQUOR #1 | #2 | #6 | FOSSIL FUEL #7 | #8 | #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

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## TABLE A-9 - Sawmill Steam and Power Generation

| Steam from (to) Sawmill Powerhouse - | | | | Power Generated | |
|---|---|---|---|---|---|
| $10^6$ Btu of 140 LB Steam | | | | MWH | |
| 1975 AUG. | 158448 | | | 1975 AUG. | 0 |
| SEP. | 154924 | | | SEP. | 0 |
| OCT. | 213599 | | | OCT. | 0 |
| NOV. | 145304 | | | NOV. | 0 |
| DEC. | 115875 | | | DEC. | 0 |
| 1976 JAN. | 147701 | | | 1976 JAN. | 0 |
| FEB. | 114347 | | | FEB. | 0 |
| MAR. | 96024 | | | MAR. | 0 |
| APR. | 121108 | | | APR. | 1613 |
| MAY | 77329 | | | MAY | 1690 |
| JUNE | 27709 | | | JUNE | 800 |
| JULY | 8919 | | | JULY | 0 |
| AUG. | (1332) | | | AUG. | 0 |
| SEP. | (26957) | | | SEP. | 0 |
| OCT. | (51065) | | | OCT. | 0 |
| NOV. | 14716 | | | NOV. | 0 |
| DEC. | (11991) | | | DEC. | 0 |
| | $10^6$ Btu | $10^3$ LB | Net $10^6$ Btu | | |
| 1977 JAN. | (87490) | 22390 | (59500) | 1977 JAN. | 0 |
| FEB. | (91920) | 32960 | (50700) | FEB. | 0 |
| MAR. | (75510) | 27630 | (41000) | MAR. | 0 |
| APR. | (68200) | 37900 | (20800) | APR. | 29797 |
| MAY | (80000 est) | 37790 | (32800) | MAY | 26166 |
| JUNE | (93550) | 46380 | (35500) | JUNE | 23506 |
| JULY | (52800) | 37790 | (5600) | JULY | 19305 |
| AUG. | (49300) | 36380 | (3800) | 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 |

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## 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 |

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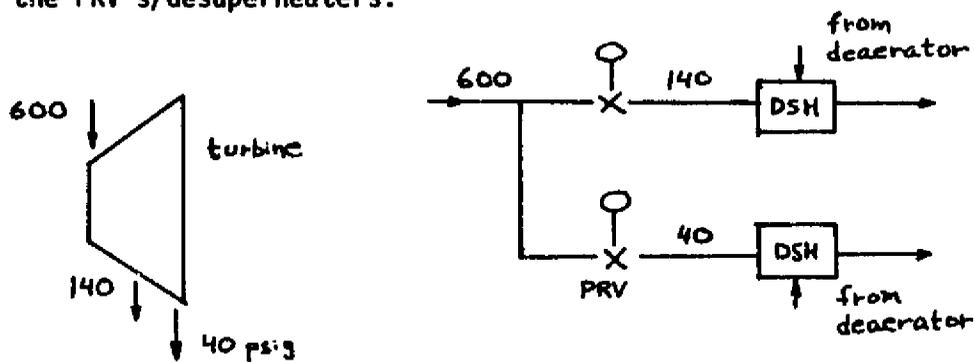
$$\dot{m}_{140_t} h_{140_t} = X \dot{m}_{600} h_{600} + \dot{m}_{de_{140}} h_{de_{140}}$$

&

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

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

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

Now,

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

or

$$\dot{m}_{600t} = \dot{m}_{600} + \dot{m}_{de}$$

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

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

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

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

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

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

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

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A similar exercise can be done with the 1250 psig system
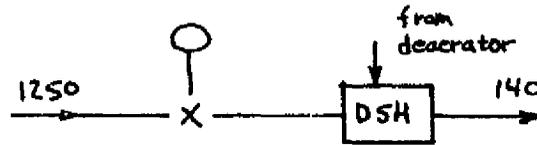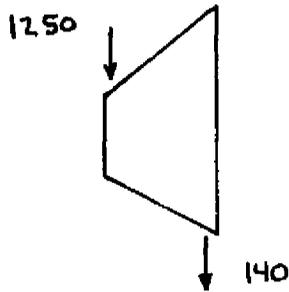
For the 1250 system, the deaerator is the 140 psig one.

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

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

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

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>
$$\dot{n}_{40_t} = 1351 - 0.62\left(\frac{3412}{15.2}\right)$$
$$= 1212$$

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

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
$$h_{de_{140}} \approx 334$$

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

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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 $\quad \left. \dfrac{\dot{m}_{de}}{\dot{m}_{600}} \right|_{140} = \dfrac{.086 + .18\ell}{L} = 0.137$

or $\quad 1.137 \left( 534000 \right) = 607,000$

giving a requirement of

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

to generate power.

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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 12C0 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
$$1.170 \left( 534000 \right) = 625000$$

is required to meet the 140 psig load

or the new steam rate is
$$\begin{array}{r} 625,000 \\ 287,000 \\ \underline{316,000} \\ 1,228,000 \end{array}$$

This new estimate gives a
$$1,300,000 - 1,228,000 = 72,000 \text{ reduction of hog fuel}$$
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

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

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


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


600/40 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 $\dot{m}_{se}/\dot{m}_{co}$ to be
used in calculating the maximum back pressure power of Fig. 2 using equation Ⓐ.

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

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

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

$$= 0.163$$

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.

| 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 | | |

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| 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 | 35 |
| 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 |

155

| 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 | | |

| 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 | TIME | SWINGING STEAM FLOW, $10^3$ LB/HR |
|---|---|---|---|
| 2:15 a.m. | 177 | 4:32 a.m. | - 85 |
| 2:20 | 195 | 4:33 | - 90 |
| 2:21 | 180 | 4:35 | 118 |
| 2:25 | 205 | 4:38 | 160 |
| 2:28 | 195 | 4:40 | 305 |
| 2:30 | 205 | 4:45 | 275 |
| 2:31 | 245 | 4:47 | 340 |
| 2:33 | 230 | 4:50 | 280 |
| 2:35 | 250 | 4:53 | 320 |
| 2:39 | 235 | 5:00 a.m. | 280 |
| 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 | | |

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| 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 |
| 23:25 | 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 | 30C | | |
| 4:59 | 325 | | |
| 5:00 a.m. | 320 | | |
| 5:01 | 310 | | |
| 5:05 | 350 | | |

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# 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 $3.2 \times 10^6$ 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 |

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## 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 | <u>120</u> |
| 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 | 3 |
| 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

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

Annual fossil consumption reduction, equivalent $10^6$ BBLS $\frac{oil}{YR}$, at 1100 $\frac{BTU}{LB STM}$ and 80% BLR.EFF.

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

# 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 pulp-
ing (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

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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,

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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 | 3 | 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

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

STEAM GENERATED IN PULP AND PAPER MILLS

| Major product line | Total U.S. | Northeast | South Atlantic | North Central | South Central | Western |
|---|---|---|---|---|---|---|
| | | 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

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

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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.
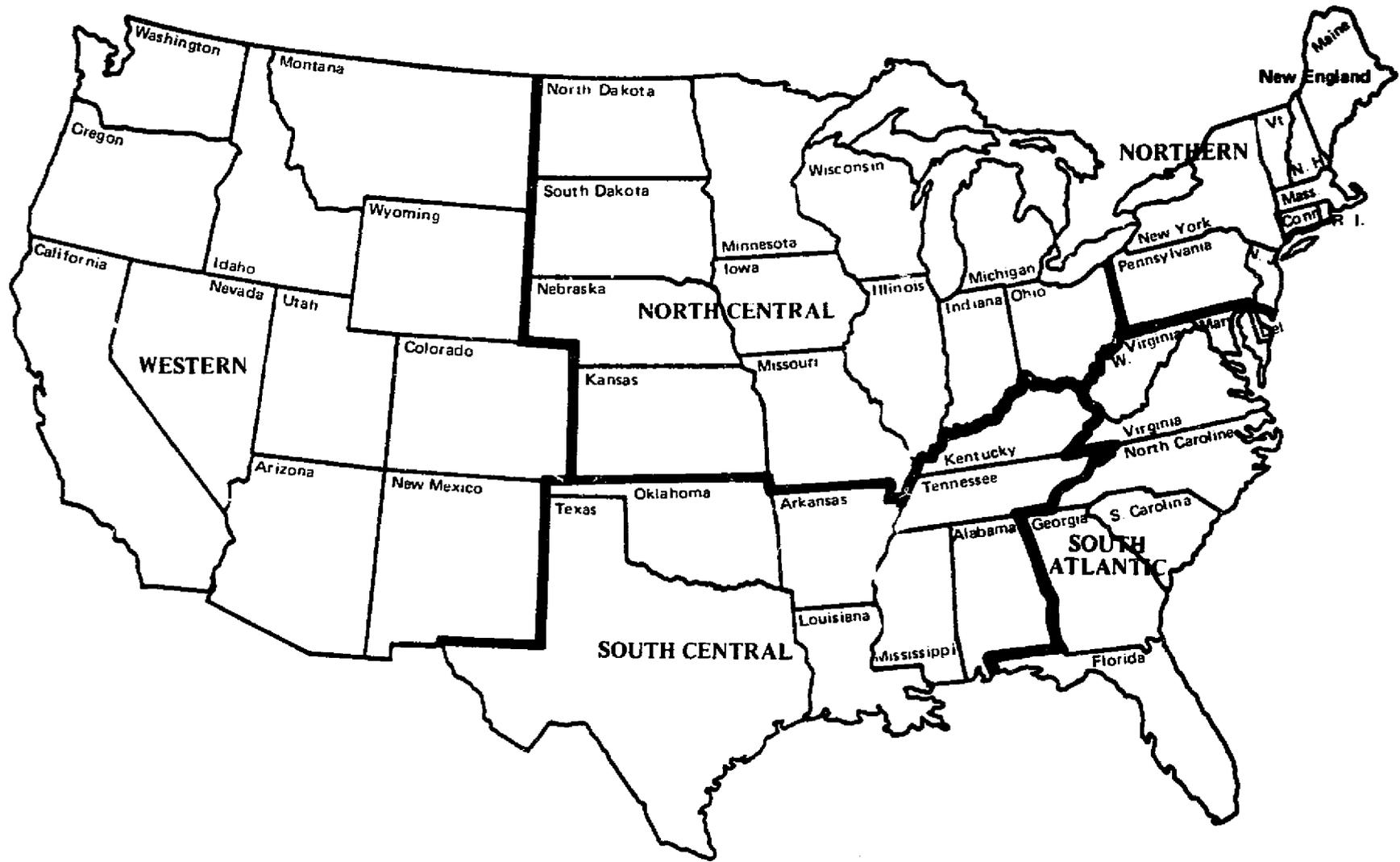
Figure C-1. The Five Wood Industry Regions

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 these 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, de-
pending 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 particle-
board 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 |
| Average fuel use per consumer and per ton of capacity in mills that use hog fuel. (60 mills) | | | | | | |
| 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

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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-

ty-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:

. <u>Sold</u>--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.

. <u>Fuel</u>--that portion of available residues that is used as fuel without sale. This category includes all forestry residues used as fuel.

. <u>Wasted</u>-- 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).

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## 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 | 1ɔ1,8ɔɔ |
| 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 | ‒,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 | 1u.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.

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*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.

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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 | 5.9 | 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 |

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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 proc... 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 cogenerction. 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 new solid 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    <u>TES-INDUCED CHANGES IN ENERGY USE</u>


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


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## 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

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## 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

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

Annual Fossil Fuel Savings at the Electric Utilities

$$356 \text{ MWH} \times 10.5 \text{ MMBtu/MWH} \times 8760 \text{ Hrs/Yr} = 32{,}744{,}880 \text{ MMBtu}$$

$$\text{Total (10\% Shift + Cogeneration} = 112{,}583{,}520 \text{ MMBtu}$$

$$\text{Oil Equivalent} = 17.87 \text{ MMBL}$$
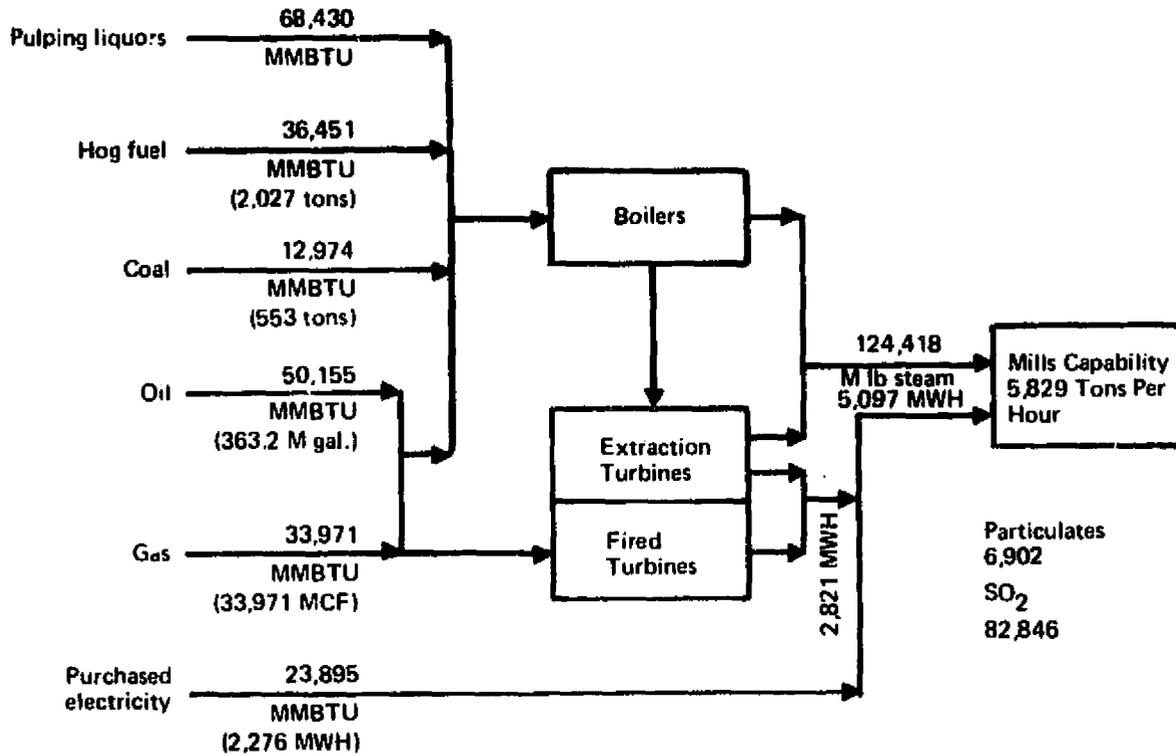
Figure C-2. Hourly Energy Use For: 214 U.S. Integrated Mills
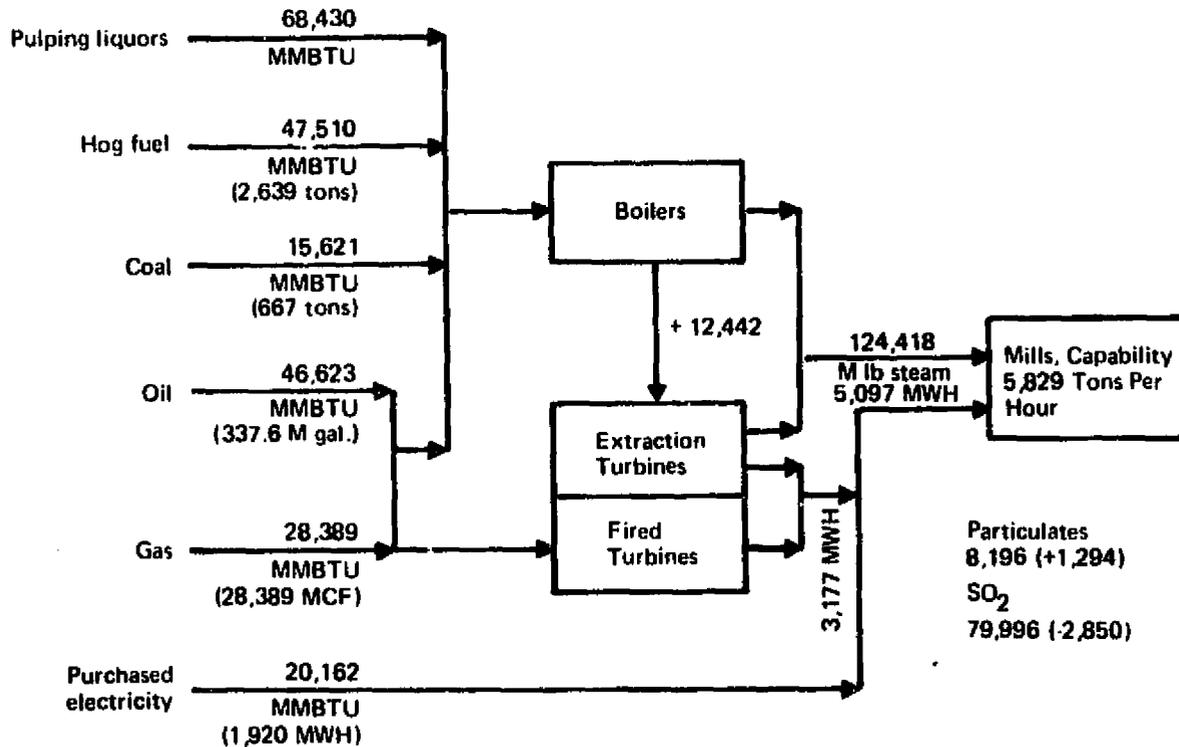


Figure C-3. Hourly Energy Use For: 214 U.S. Integrated Mills with 10% Shift of Steam Generation To Solid Fuels and Through Cogenerating Turbines

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

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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

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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

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*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

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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

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* 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 | $SO_2$ |
| **AT MILL** | | | | | |
| HOG FUEL | 453 | -0- | | 518 | -0- |
| COAL | 316 | 5,212 | | 361 | 5,952 |
| OIL | -0- | 15,441 | | -0- | 14,619 |
| **AT UTILITY** | | | | | |
| 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 (E) |
|-----------|-----------|
| 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 nave 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.

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*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 | $SO_2$ |
| **AT MILL** | | | | |
| HOG FUEL | 1,467 | -0- | 1,929 | -0- |
| COAL | 247 | 2,964 | 325 | 3,898 |
| OIL | -0- | 18,439 | -0- | 16,012 |
| **AT UTILITY** | | | | |
| 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

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# 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

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## 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 | $SO_2$ | 10% FUEL SHIFT and COGENERATION PARTICULATES | $SO_2$ |
|---|---|---|---|---|
| **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

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## 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 0.2 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.

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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 *f* 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.

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$\Delta W_f$, reduction of fossil fuel boiler steaming rate
resulting from TES use (pounds/hour)                      60,000

$\Delta E$, 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 ojtain 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.
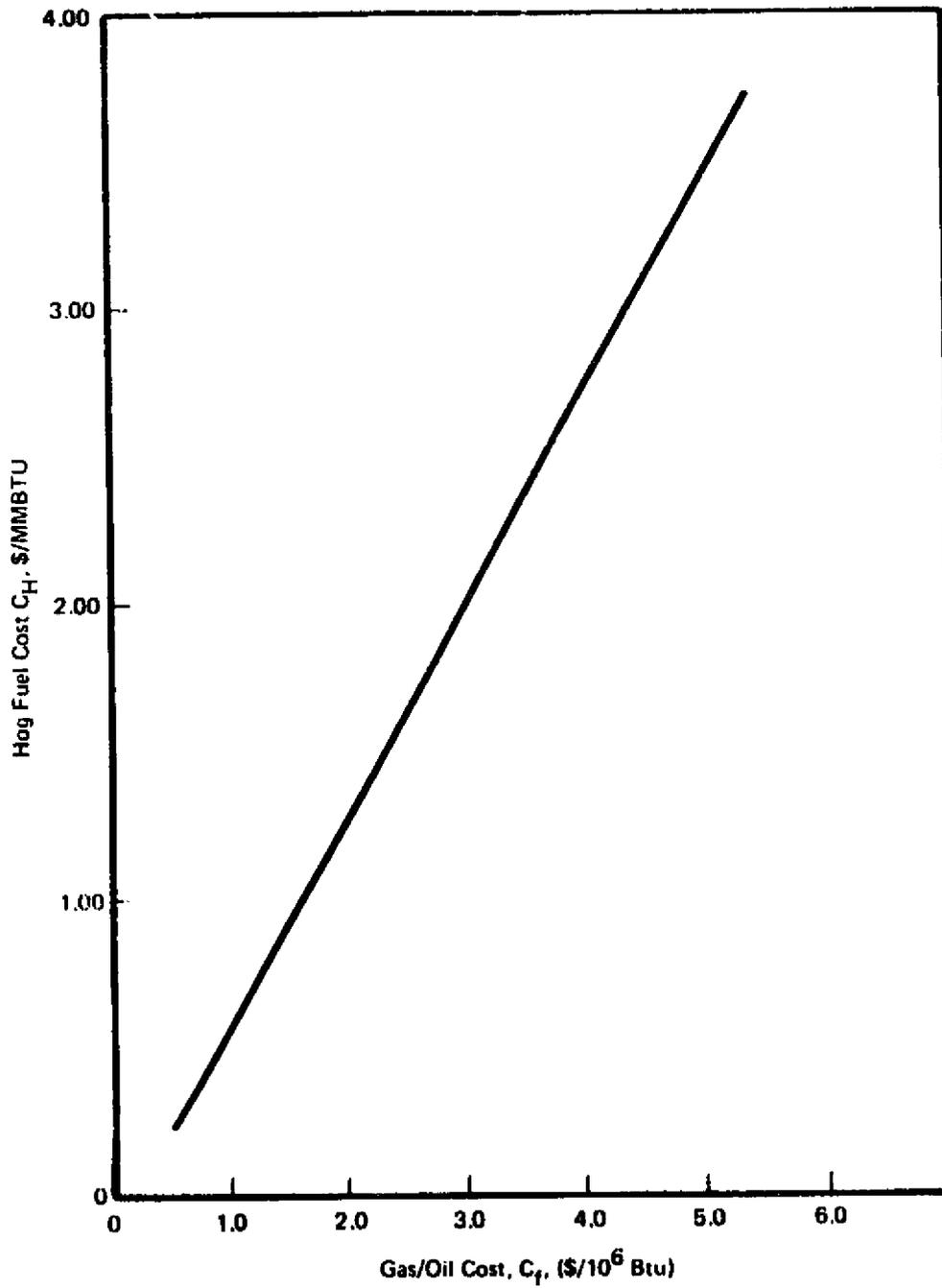
*Figure C-4.  Sensitivity of Hog Fuel Price to Gas/Oil Cost*

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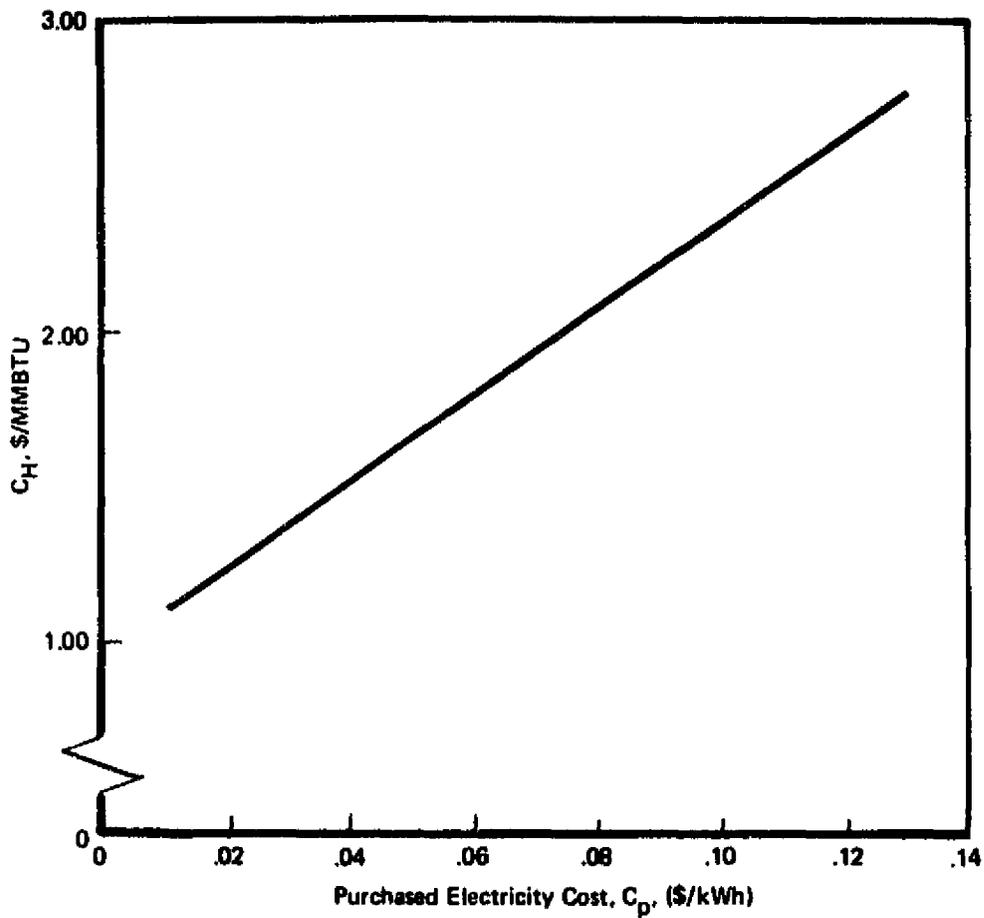
Figure C-5. Sensitivity of Hog Fuel Price to Electricity Cost
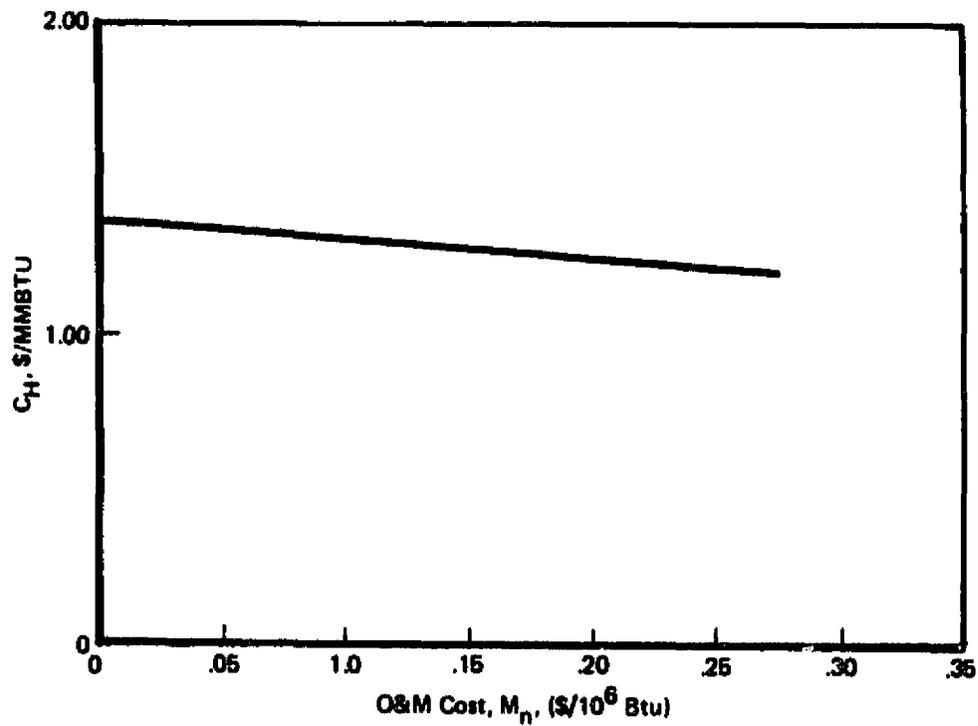


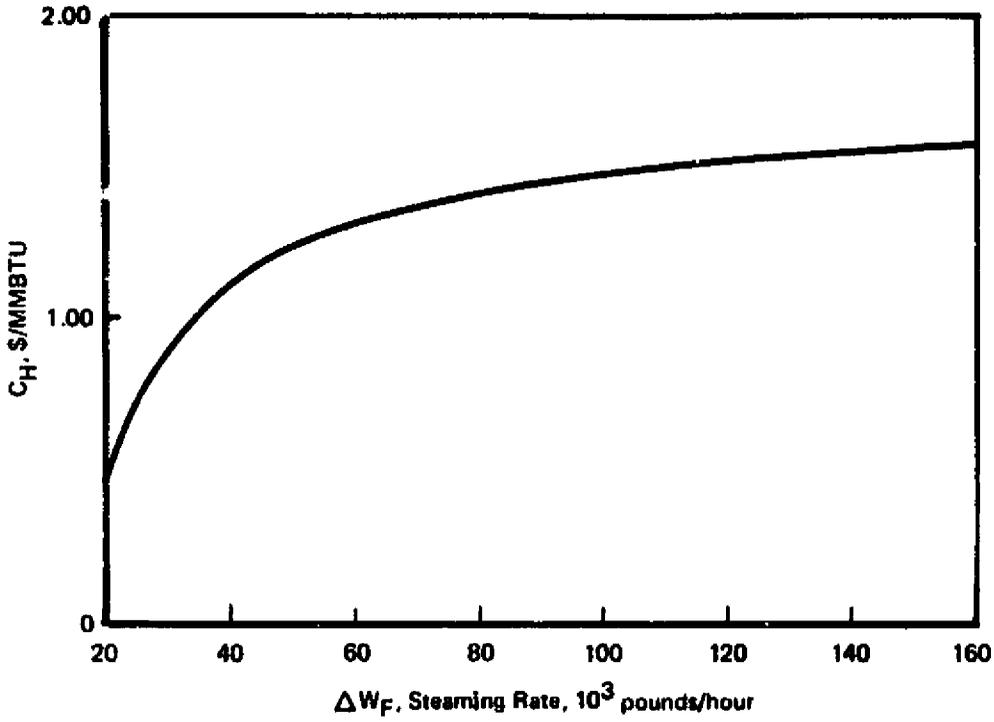Figure C-6. Sensitivity of Hog Fuel Price To Solid Fuel Boiler O&M Cost

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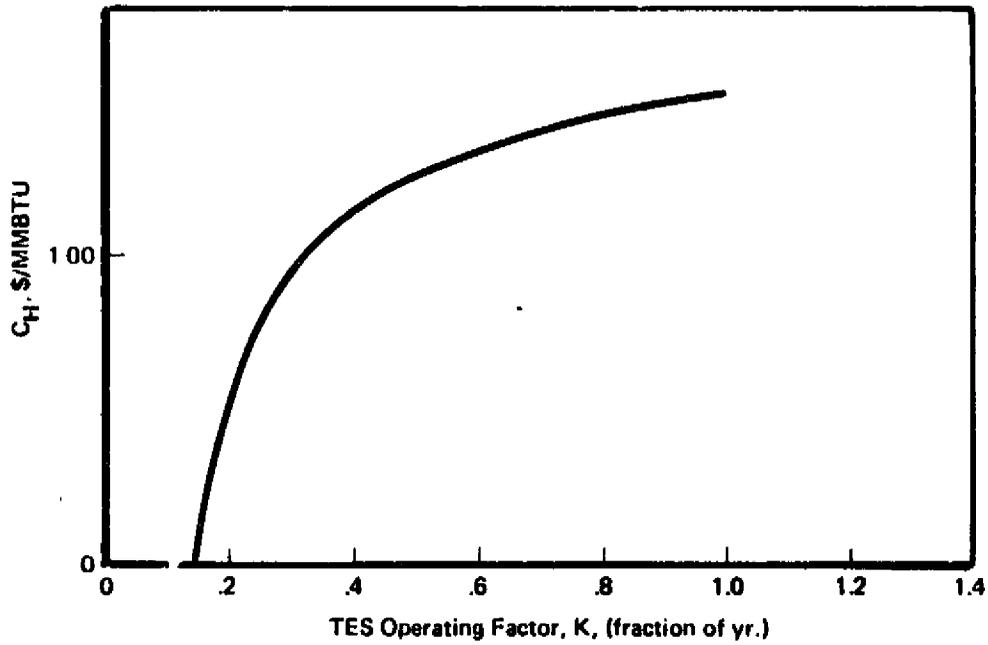Figure C-7. Sensitivity of Hog Fuel Price To Steaming Rate Increment



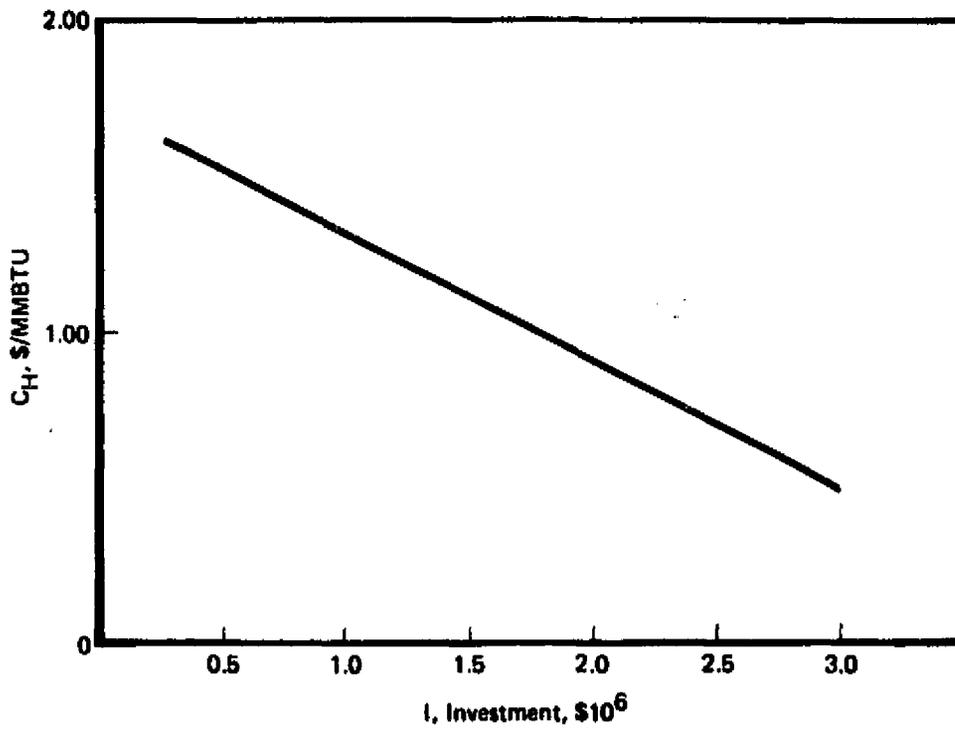Figure C-8. Sensitivity of Hog Fuel Price To Annual Operating Factor of TES System

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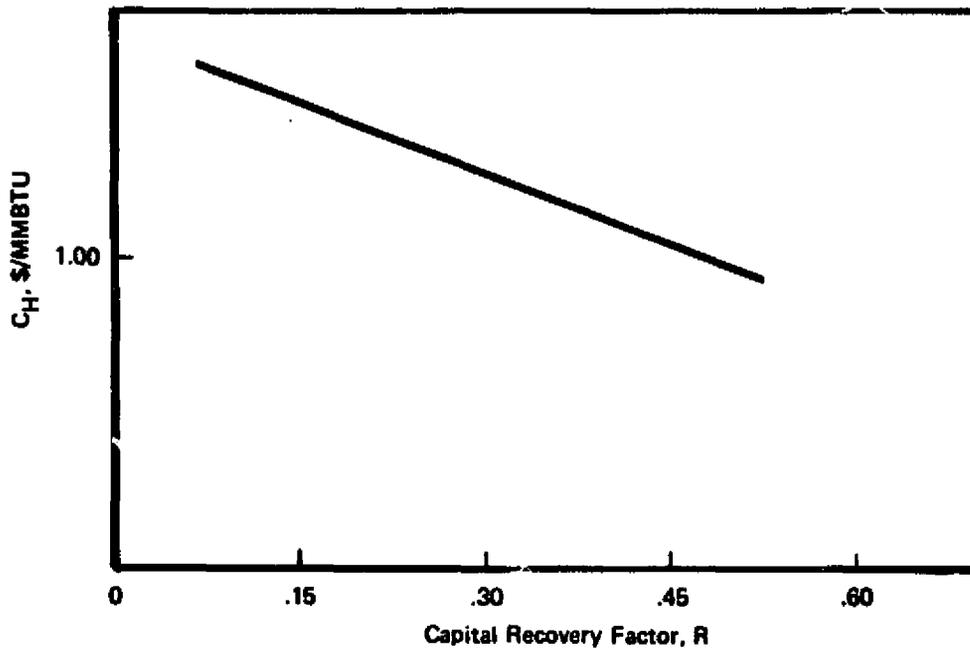
*Figure C-9. Sensitivity of Hog Fuel Price to TES Investment*



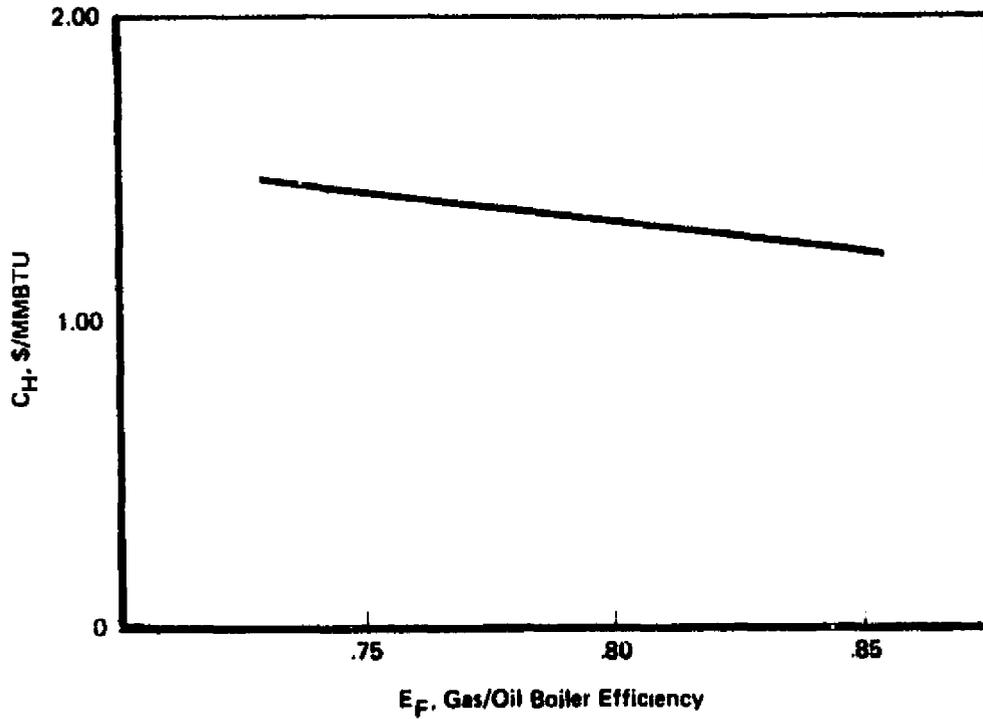*Figure C-10. Sensitivity of Hog Fuel Price to Capital Recovery Factor*

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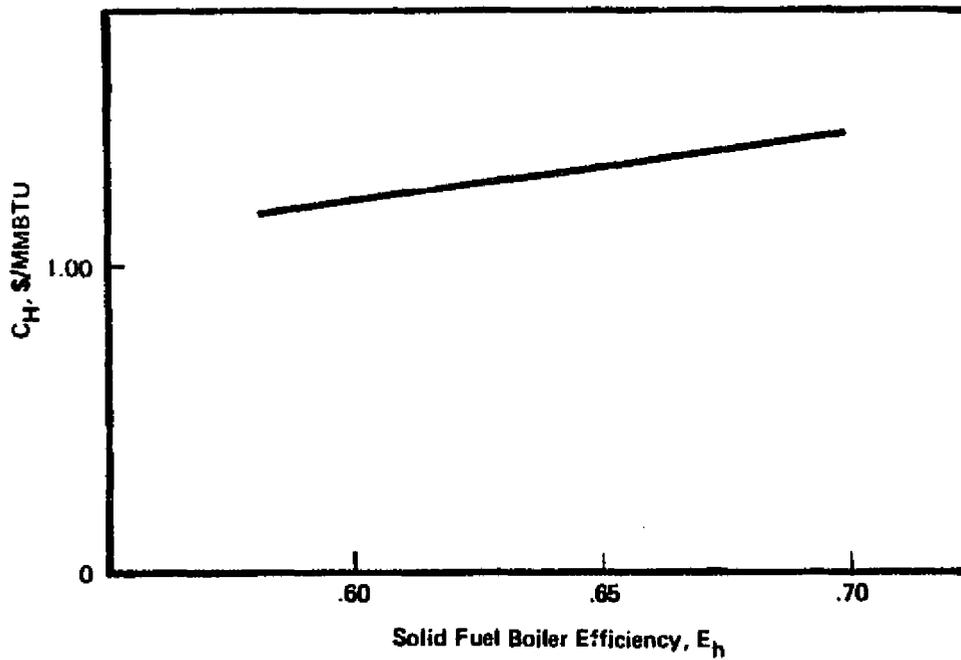


*Figure C·12. Sensitivity of Hog Fuel Price to Solid Fuel Boiler Efficiency*

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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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