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THERMAL ENERGY STORAGE/HEAT RECOVERY AND ENERGY CONSERVATION IN FOOD PROCESSING

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ABSTRACT

Modern food processing operations often require that the temperature of the processed foodstuff be raised or lowered. These operations result in energy consumption by refrigeration or heating systems, and a portion of this energy can be recovered from waste heat streams for reuse in the processing operations. This paper addresses the recovery of waste heat and the storage of thermal energy as a means of energy conservation in food processing. An energy conservation project in a poultry processing plant sponsored by the U.S. Department of Energy and conducted by Georgia Tech is used as an illustrative example of potential applications of heat recovery and thermal energy storage.

INTRODUCTION

The U.S. food processing industry utilizes approximately 65% of the total energy consumed by the industry for thermal processes[1]. These processes include cooking, refrigeration, washing, pastuerizing, sterilizing, evaporation, drying, singeing and space heating. In some cases, such as pastuerization of raw milk, heat recovery is routinely practiced by the industry. However, many of these thermal processes result in the discharge of reject heat to the plant drain system or to the atmosphere. As a result of rising energy costs and increasing uncertainty of energy supplies, the food processing industry is seeking means for recovery and reuse of reject heat to the greatest extent possible. Processing operations are often batch processes which yield intermittent discharges of reject heat, and the recovery of heat from such discharges can be made more economically attractive by incorporating thermal energy storage in a heat recovery system. Thermal energy storage can also increase the degree of recovered heat utilization by uncoupling the recovered energy source from the ultimate energy end use.

A project conducted by the Georgia Tech Engineering Experiment Station to demonstrate waste heat recovery in the Gold Kist, Inc. poultry processing plant located in Ellijay, Georgia will be used as an example of the potential for heat recovery in a food processing facility. The incorporation of thermal energy storage to increase the amount of waste heat recovery and reuse will also be discussed. This application of waste heat recovery has resulted in a potential savings of 45,800 gallons of fuel oil annually, or 18.7% of the current fuel oil requirements. The addition of thermal energy storage to this system could result in an additional savings of 11,800 gallon of fuel oil annually.

WASTE HEAT RECOVERY

Heated water is used frequently for food processing operations such as washing or cooking. In poultry processing, heated water is used to "scald" slaughtered poultry to facilitate the removal of feathers. This scalding process takes place in a tank holding several thousand gallons of water maintained at 128-130°F. This scald tank is constantly overflowed to maintain sanitary conditions, and the overflow rate of hot water is typically 0.5-1.0 quart of water per bird processed. In lieu of wasting this hot water to the plant drain, a heat exchanger was installed at the Gold Kist plant to preheat scald tank makeup water by screening, collecting and pumping the overflow from the scald tank through the heat exchanger counterflow to the incom-

ing makeup water, resulting in significant recovery of waste heat.

In addition to liquid waste heat streams, many food processing facilities use refrigeration systems to process foodstuffs. The heat which the refrigeration system removes from the product to be cooled is generally rejected to the atmosphere via evaporative condensers or cooling towers. The Gold Kist plant operates a large (400 tons of refrigeration) ammonia refrigeration system which utilizes reciprocating compressors and evaporative condensers. Of the heat rejected in the condenser of this system, approximately 85% (5.16×10^6 Btu/hr) is the latent heat of condensation available at 85-95°F. The remaining 15% (9.1×10^5 Btu/hr) is superheat available at 250-95°F. For the purposes of waste heat recovery, a heat exchanger was installed in the hot ammonia refrigerant line between the compressors and the condensers for the purpose of transferring heat from the ammonia to the makeup water to be used in the scald tank which had been previously heated by the heat exchanger described in the preceding paragraph. This heat recovery system was designed to recover only the superheat from the ammonia to utilize the highest temperature energy available. A large quantity of additional heat is recoverable, if the lower temperature (85-95°F) energy is usable.

Design Considerations

The primary component of any heat recovery system is the heat exchanger. The selection of the heat exchanger will be affected by several criteria:

- Waste heat stream (liquid or gas)
- Heat receiving stream (liquid or gas)
- Efficiency of heat transfer desired
- Pressures of waste stream and receiving stream
- Potential for cross-contamination between waste stream and receiving stream
- Potential for heat exchanger fouling
- Materials of construction

Often, waste heat sources, such as the scald tank overflow at the Gold Kist plant, contain contaminants which will cause excessive fouling of the heat exchanger. In these cases, pretreatment of the waste heat stream before introduction into the heat exchanger should be considered. For the heat exchanger at the scald tank overflow, Georgia Tech engineers installed a self-cleaning screen which removed feathers, dirt, etc. from the hot wastewater prior to pumping it through the heat exchanger. For the heat exchanger in the ammonia gas line, consideration was given to possible fouling due to oil entrained in the ammonia. However, the oil was not deemed to be a serious contaminant and, therefore, the only provision for oil removal made was to elevate the heat exchanger above the downstream ammonia condensing system.

The actual heat exchangers selected for the Gold Kist plant were a plate and frame type for the scald tank overflow, and a shell and tube type for the ammonia desuperheater. These selections were based on the following considerations:

- Plate and frame type - high heat transfer coefficient; suitable for use with water at the pressure anticipated; easy to clean; compact in size.
- Shell and tube type - typically used for gas-to-liquid heat transfer; low pressure drop on shell (ammonia) side; suitable for ammonia-to-water heat transfer with specified material(s) of construction; suitable for high pressures encountered in ammonia system.

Operation of Heat Recovery Systems

Heat recovery system components should be waterproof and corrosion resistant for operation in a food processing facility which is washed down regularly. Insulation on components should be protected with a waterproof jacket to prevent conditions conducive to bacterial growth. The systems should be easy to clean, especially where contaminated waste heat streams are involved in heat recovery. Cross-contamination of the waste stream and the medium to be heated must be avoided by controls which can detect a condition where such contamination occurs and either shut the system down or bypass it. In the system utilizing a heat exchanger which transfers heat from a refrigerant gas to a receiving stream, a double tube sheet construction or a double wall heat exchanger may be necessary to prevent the possibility of the pressurized refrigerant contaminating the medium to be heated.

The two heat recovery systems installed at the Gold Kist plant were integrated into a two-stage heating system utilizing two separate waste heat

sources. Actual performance data for this integrated system is presented in Figure 1. By utilizing the lower temperature waste heat system (scald tank overflow) to pre-heat makeup water, a higher temperature is attainable at the ammonia desuperheater. A similar arrangement could be obtained by utilizing the latent heat of condensation from the refrigerant itself before recovering the higher temperature superheat. However, in the Gold Kist plant, the heat recovery system at the scald tank overflow was less expensive than adding an additional heat exchanger to the refrigeration system which would condense the ammonia.

The operation of the heat recovery systems should be monitored to detect any excessive fouling which will retard heat transfer, and to detect any malfunctions which will reduce system effectiveness.

THERMAL ENERGY STORAGE

Quite often the recovery of waste heat will not coincide with the intended use of the recovered heat. For example, heat recovered from a refrigeration system may be stored during a processing shift, to be used at a later time for plant washdown. Thermal energy storage also applies to the storage of refrigeration in the form of ice or chill water storage. This concept is frequently practiced in the poultry processing industry, where ice is manufactured and stored 24 hours/day, although ice is only used during the 8 or 16 hour processing shift. The advantage of thermal energy storage lies in the fact that the production or recovery of thermal energy (hot or cold) can be independent of the use of the energy in food processing operations.

Thermal energy storage can also be utilized in batch operations where waste energy is available in "surges". For example, a retorting operation might entail discharging a quantity of hot water at a rate which makes immediate heat recovery unfeasible. By adding storage capacity, the hot water could be stored and the heat recovered from the stored water at a rate which is independent of the original hot water discharge.

Waste heat which is available in a hot gas stream (e.g., an oven exhaust) is not directly amenable to storage. To facilitate thermal energy storage in this case, an intermediate heat transfer fluid may be utilized, with the heated fluid serving as the storage medium. An example of this system is shown in Figure 2. Depending on the temperature of the waste heat source, water can be used as the storage medium and reused either directly or as a heat source for some other process. For temperatures higher than 250°F, organic heat transfer fluids may be suitable for heat recovery from hot gas streams.

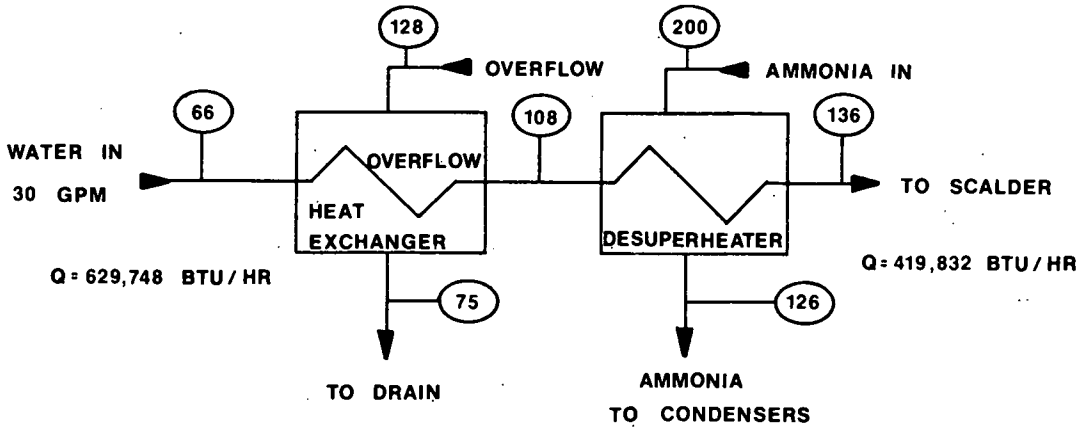
In considering the use of thermal energy storage, it should be noted that the amount of recovered heat which can be reused will be less than with a system which can utilize the recovered heat directly. This is due to the heat loss from the storage vessel and the additional inefficiency resulting from the heat transfer from storage to the ultimate end user. However, storage of thermal energy will provide the ability to use the recovered energy independent of the actual production of the energy to be recovered.

The integrated heat recovery system installed and operating at the Gold Kist plant could utilize thermal energy storage to allow recovery of the maximum amount of energy which is available from the system. The water heated by the heat recovery system would be directed to an insulated water storage tank. Heated water from the storage tank would be pumped as needed to the scald tank for makeup, as with the present system operation. However, with a storage tank incorporated in the system, several additional benefits would accrue:

- Water could be recirculated through the ammonia desuperheater, recovering the maximum amount of heat;
- Water could be added to the heat recovery system at a flow rate greater than the rate of makeup to the scald tank, creating a net positive fill rate of the storage tank;
- Heated water could be pumped from storage for use in the plant cleanup operations at times other than processing shifts; and
- Heated water from the storage tank could be used to fill the scald tank (volume of 3000 gallons) at the start of the processing shift.

The additional energy which could be recovered and reused by incorporating a hot water storage tank of approximately 10,000 gallons volume in the

EXISTING GOLD KIST HEAT RECOVERY SYSTEMS PERFORMANCE



TEMPERATURE IN DEGREES F

FIGURE 1

THERMAL ENERGY STORAGE WITH A GASEOUS WASTE HEAT STREAM

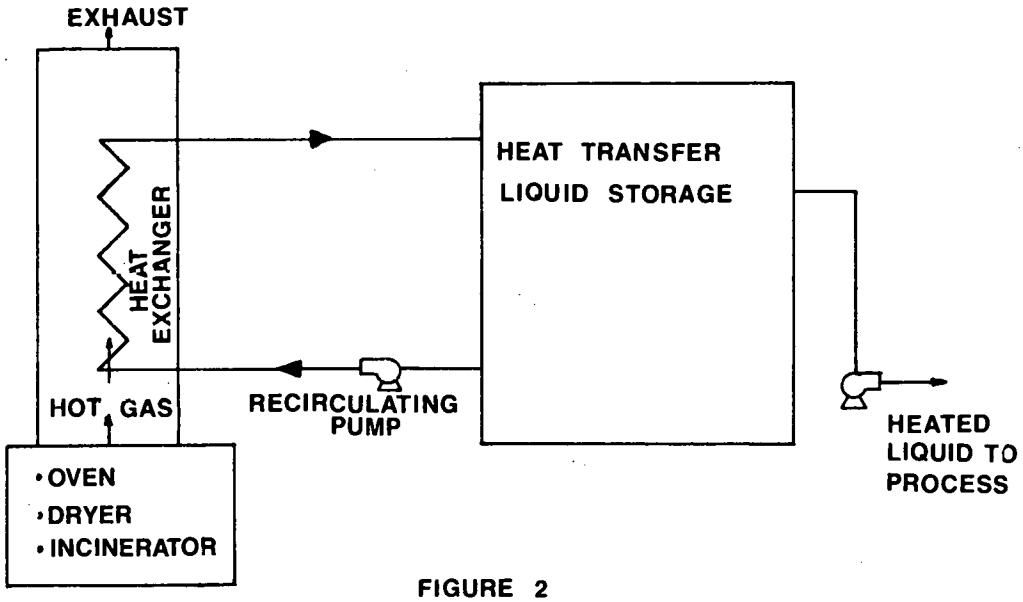


FIGURE 2

Gold Kist heat recovery system makes the additional investment attractive. Gold Kist and Georgia Tech are planning to add this storage capacity to demonstrate the value of such a system in further reducing plant energy requirements.

SUMMARY

Operations involved in food processing plants often result in waste energy streams which can be recovered and reused to effect a reduction in plant energy needs. Waste heat recovery systems can be retrofitted to processes discharging hot wastewater or hot gases. The heat rejected from refrigeration system condensers is a common and recoverable waste heat source in food processing operations. Careful considerations of heat recovery system design must be made to assure no contamination of food products occurs; to insure reliable and efficient system operation; and to maximize the recovery of usable thermal energy. The use of thermal energy storage in conjunction with a heat recovery system can, in some cases provide additional energy savings and allow more flexible operation of the heat recovery system by making the reuse of recovered energy independent of the production of the waste energy to be recovered.

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PRODUCTION OF BIOGAS FROM WASTEWATERS OF FOOD-PROCESSING INDUSTRIES

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ABSTRACT

An Upflow Anaerobic Sludge Blanket Process used in converting biodegradable, soluble, organic pollutants in industrial wastewaters to a directly-burnable biogas composed mainly of methane has been developed, tested, and commercially applied in Holland. Operations on wastewater from the processing of sugar beets have shown hydraulic retention times of less than 10 hours with reactor loadings of at least 10 Kg COD per m^3 digester volume per day and purification efficiencies exceeding 90%. Biogas production is at a rate of about 1 therm (100000 BTU) per 10 Kg COD treated. A moderately sized (1000 m^3) wastewater treatment plant processing the order of 10000 Kg COD per day will, therefore, produce the order of 1000 therms of energy per day while, at the same time, reducing the COD level in the effluent by an order of magnitude.

The set of conditions required for efficient operation of this anaerobic process will be discussed. The process is unique in its mixed sludge bed approach allowing for tolerance of swings in Ph (6-8) at relatively low temperatures ($32^{\circ}C$-$38^{\circ}C$) which can be readily achieved from most wastewater streams with little expenditure of additional energy. Sludge production is remarkably low, only about 5% of the COD loading, greatly alleviating disposal problems. These characteristics are conducive for the use of the anaerobic process to recover energy from a variety of wastewaters rich in carbohydrate-type substances as produced routinely as a by product of many types of food processing activities.

INTRODUCTION

Man's use of anaerobic digestion to purify wastewater and to produce, as a by-product, a burnable mixture of methane and carbon dioxide gas, herein termed biogas, is a very old practice, particularly with respect to implementation in municipal treatment systems. However, with the flow-through processes typically employed, hydraulic retention times are necessarily long (measured in weeks) and digesters have been found to be very sensitive to upset with relatively small changes in feedwater composition, quantity, temperature, or alkalinity. As recently as seven years ago, it was the opinion of experts in the field that methane fermentation had potential for the future only if increased reliability of the anaerobic digestion process could be achieved economically and if the recovery of biogas could compete satisfactorily with other means of obtaining waste energy (1). Widespread industrial use of anaerobic digestion as a principal means of wastewater purification and energy recovery awaited a breakthrough in technology combined with a strong push towards stricter pollution standards and a basic change in philosophy regarding the potential value of waste.

At about the same time, researchers at the Agricultural University of Wageningen in the Netherlands were developing and testing a new concept in digester design. The basic idea underlying the concept is that anaerobic sludge is highly settleable within a reasonable range of hydraulic loadings providing that sludge particles which are attached to produced bubbles of biogas can be effectively separated from the gas. The sludge is, therefore, retained as a stratum or "bed" within the digester and the wastewater percolates upwards through the layer. Biogas is produced as the dissolved carbohydrate material is converted first to fatty acids and then to methane. This Upflow Anaerobic Sludge

Blanket Process (UASB) employs a specially designed baffle for separation of the gas, liquid, and solid phases near the top of the digester. This very important feature enables the sludge particles to settle back towards this bed and to be retained within the digester for long periods of time. Since mechanical agitation is not required with this process for effective sludge-water contact, the methane forming bacteria have the opportunity to grow in an environment which remains relatively undisturbed and to adapt to the wastewater feed under physical and chemical conditions which can remain optimal for development of the strain. The Wageningen studies showed that organic loads of order 10 Kg COD per cubic meter of reactor volume per day could be treated with the upflow process with a purification efficiency of order 90%.

CSM APPLICATION

Although the initial work at Wageningen was with potato starch wastewater, the first industrial scale application with this process was carried out by Centrale Suiker Maatschappij (CSM), the largest privately-owned beet sugar company in Holland. Their factories had been treating wastewater with oxidation ponds which carried the serious drawbacks of large energy consumption, demanding requirements for space, continuous nuisances with odors, etc. Since the beet sugar wastewater consists largely of carbohydrates easily converted to volatile fatty acids, the Wageningen work on upflow anaerobic digestion became very relevant to the waste treatment needs of CSM. Although the decision to apply the upflow anaerobic process was taken from the point of view of waste treatment effectiveness, the potential for energy recovery in the form of methane end product was readily realized by the CSM management.

Work started at CSM in 1974 with the engineering of a 6 m^3 pilot plant, followed in 1976 by the construction of a 30 m^3 demonstration plant at their factory in Breda. The 30 m^3 plant has been operating nearly continuously since its installation, a situation made possible by the availability not only of the seasonal beet sugar wastewater, but also of a year-round waste stream from a by-products liquid sugar plant. Early tests with the 30 m^3 Breda digester were instrumental in obtaining good data for optimal dimensioning of an industrial-scale (200 m^3) plant which was constructed at the CSM factory in Halfweg during the 1977 sugar beet harvest. This initial anaerobic reactor at the Halfweg factory was designed to handle a portion of the effluent stream pumped from mud fields and recirculated to the factory. The mud field effluent had its origin in the sugar beet wash and transport water.

Results from the 200 m^3 reactor were so encouraging that, in 1978, a full-sized (800 m^3) reactor was constructed at Halfweg to process the entire effluent flow (200 $m^3\ h^{-1}$) pumped from the mud fields. A schematic of the sugar beet waste water flow as it exists today at Halfweg is shown in Fig. 1 along with some typical values for COD concentrations observed within the various loops.

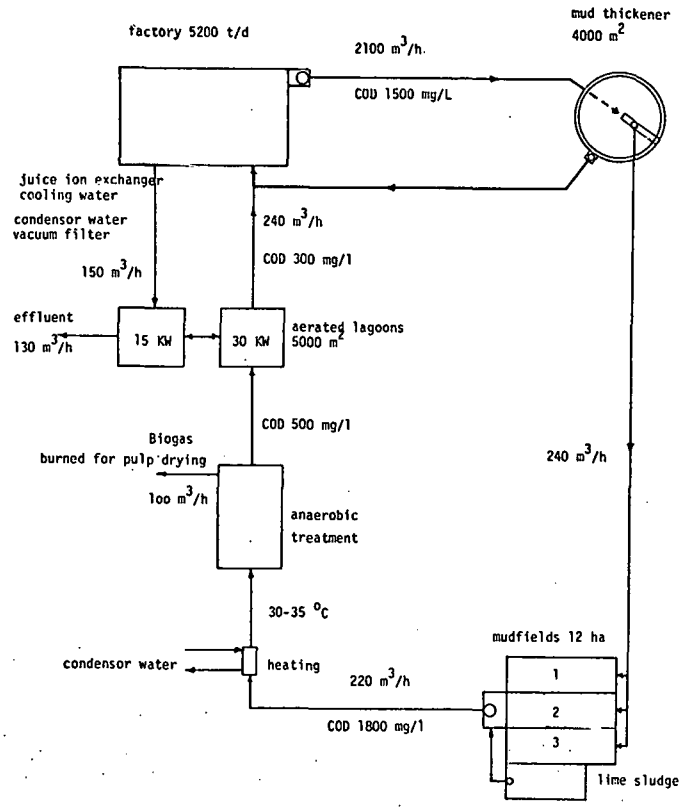


Fig. 1 schematic flow diagram of sugar beet wastewater stream at Halfweg utilizing 800 m^3 anaerobic digester.

PURIFICATION PERFORMANCE

The work carried out at the two CSM factories with the anaerobic reactors of four different sizes (6 m^3, 30 m^3, 200 m^3, and 800 m^3) showed consistently that, with moderately high (3500-6000 ppm) incoming COD concentrations, it is possible to achieve routinely a reduction of the soluble COD by an order of magnitude (90%). It appeared that the series of results obtained from the small-scale

plants can be directly extrapolated to industrial-scale systems as long as the hydraulic loading on the settler plates can be parameterized proportionately.

Table 1 lists some of the principal treatment parameters with results obtained during 2 1/2 years of work at CSM from the 6 m^3, 30 m^3, and 200 m^3 plants at Breda and Halfweg. Of particular interest are the results from the 30 m^3 plant with intercampaign wastewater (liquid sugar) in May, 1977, and the 200 m^3 plant with campaign wastewater (from mudfields) in December 1977. Notice that the fatty acid composition of the COD load is very different between these two streams, with relatively little acidification evident in the liquid sugar waste. The incoming COD concentration in these two streams, however, was very similar, and the reduction of COD levels through the system in both cases was about 90%. This suggests that, although some quantity of fatty acids in the wastewater is desirable, the exact amount can be highly variable without degrading effective system performance. This means that a large variety of waste streams composed of carbohydrate and/or soluble protein substances should be amenable to effective treatment with the upflow anaerobic process. It should also be noted that the presence of suspended solids in concentrations up to 1000 ppm did not appear to affect performance. Of course, this suspended material is not treated by the system and, providing that the particulates have poor settling characteristics, is passed directly through the reactor.

It is well to look also at the hydraulic retention times associated with the COD reduction data. For COD concentrations of 2000-4000 ppm, the hydraulic retention times found from the studies summarized in Table 1 varied from 2.6 to 9.0 hours. The results of work carried out with the 200 m^3 reactor at Halfweg showed a 90% purification with a hydraulic retention time of about 7 hours. On the basis of this result and the expectation that an even faster flow would not seriously degrade performance, the full-scale 800 m^3 reactor was designed with the specification of a 4-hour hydraulic retention time. As we shall see, this specification was achieved without loss

Table 1. Treatment Parameters - CSM Results

Parameter	6 m^3 Pilot Plant		30 m^3 Pilot Plant		200 m^3 Industrial Plant
	Intercampaign Wastewater May 1975	Campaign Wastewater Nov 1975	Campaign Wastewater Nov 1976	Intercampaign Wastewater May 1977	Campaign Wastewater Dec 1977
pH	6.5	7.4	7.0	7.1	7.1
Temperature (^oC)	32	32	30	33	30
COD Load (Kg m^{-3})	4.0	3.6	2.0	3.5	4.2
Hydraulic Retention Time (h)	6.0	2.6	4.4	9.0	7.1
COD Capacity (Kg m^{-3} d^{-1})	16	32	11	11	14
COD Reduction (%)	91	75	63	93	90
Total Sludge (Kg SS)	240	360	350	1000	6000
VSS in Sludge (%)	75	66	77	84	35
Sludge Load (Kg COD Kg VSS^{-1} d^{-1})	0.5	0.8	1.3	0.4	1.3
Gas Production (m^3 m^{-3} d^{-1})	7.4	---	3.0	4.5	4.7
Gas Production (m^3 h^{-1})	1.9	---	3.8	5.6	39.2
Methane Component (%)	70	90	90	72	83
Wastewater Acidification (% of COD)	33	60	60	20	89
Acetate (%)	10	18	22	10	40
Proprionate (%)	8	35	33	3	45
Butyrate (%)	15	7	5	5	4
Suspended Solids (Kg m^{-3})	---	0.7	0.5	---	1.0

of system effectiveness. The shorter the hydraulic retention time, of course, the more compactly (and more economically) the system can be constructed.

GAS PRODUCTION

Along with the wastewater characteristics and purification results, Table 1 also provides information about the flow rate and composition of the biogas generated by the anaerobic process. The general formulation for the conversion of a carbohydrate to methane gas can be expressed by:

$$C_NH_AO_B + (N - \frac{A}{4} - \frac{B}{2})\ H_2O \rightarrow (\frac{N}{2} - \frac{A}{8} + \frac{B}{4})\ CO_2 + (\frac{N}{2} + \frac{A}{8} - \frac{B}{4})\ CH_4$$

Proprionic acid ($C_3H_6O_2$), for example, could be expected to breakdown into CO_2 and CH_4 as follows:

$$4(C_3H_6O_2) + 2\ (H_2O) \rightarrow 5\ CO_2 + 7\ CH_4$$

The methane percentage of the total gas produced in this example is 58%. More complex chains of fatty acids generate somewhat richer methane ratios, while lower-order chains (e.g. acedic acid) generate a somewhat smaller percentage of methane.

As can be seen in Table 1, the gas composition observed from the CSM studies is in the range 70-90% methane. This very rich methane content, achieved consistently throughout the CSM testing period, may well be the result of losses of CO_2 in solution due to chemical bonding with minerals present in the water (for example, ammonium ions) and the subsequent formation of carbonate salts.

Table 2 shows the relationship between gas production and soluble COD reduction during a period of six months of testing with the 30 m^3 plant operating on wastewater from the Breda liquid sugar plant. It can be seen that during this period the total biogas yield averaged close to 0.50 m^3 per kg of COD converted, while the gas composition averaged close to 70% methane. This results in a methane yield of 0.35 m^3 per kg of COD

Table 2. Relation between gas production and COD reduction in the 30 m^3 installation using wastewater from the by-products plant "liquid sugar"

Dates	COD Reduction (kg COD/h)	Gas Production (m^3/hour)	Gas Composition (% CH_4)	Gas Yield (m^3/kg COD)
1/3/77-1/31/77	5.72	2.67	63.4	0.464
1/31-2/27	8.75	4.00	65.3	0.457
2/28-3/27	10.69	5.42	68.4	0.507
3/28-5/1	11.21	4.79	70.3	0.427
5/2-5/30	13.83	5.64	71.9	0.407
5/31-7/3	13.33	6.52	67.2	0.488
7/4-7/24	12.29	6.67	72.4	0.542

Table 3. Relation between gas production and COD load in the 200 m^3 installation in anaerobic purification of seasonal wastewater

Date	Day No.	COD Load (kg COD/hour)	Gas Production (m^3/hour)	Gas Yield (m^3/kg COD)
11/23/78	54	80.5	28.0	0.348
11/24	55	104.6	37.4	0.358
11/25	56	93.8	40.1	0.427
11/30	61	88.7	36.0	0.406
12/1	62	110.3	47.0	0.426
12/2	63	104.2	43.8	0.420
12/7	68	89.0	32.1	0.361
12/9	70	113.5	46.2	0.407
12/13	74	83.1	34.8	0.419
12/15	76	106.2	40.6	0.383

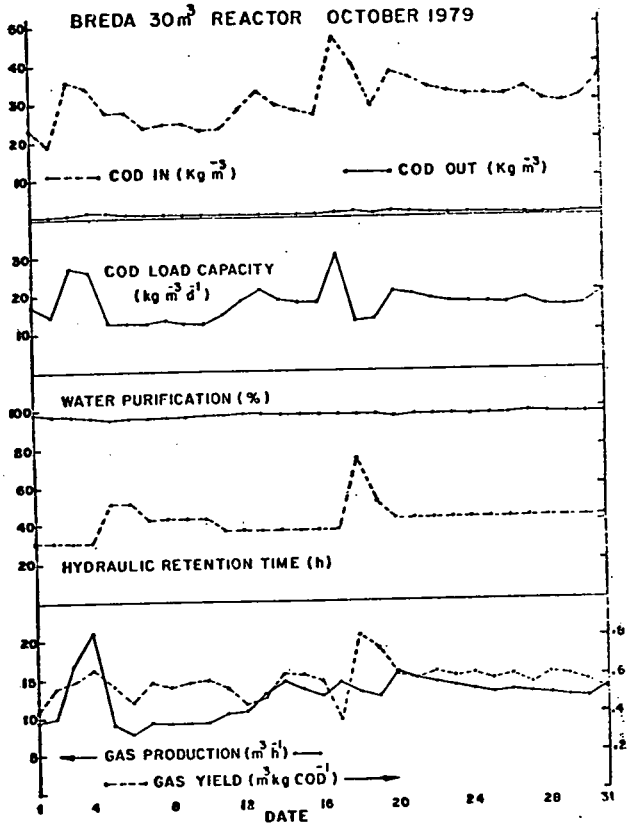


Fig. 2. Purification and gas production parameters for 30 m^3 anaerobic treatment facility at Breda; Results are for the period October 1979

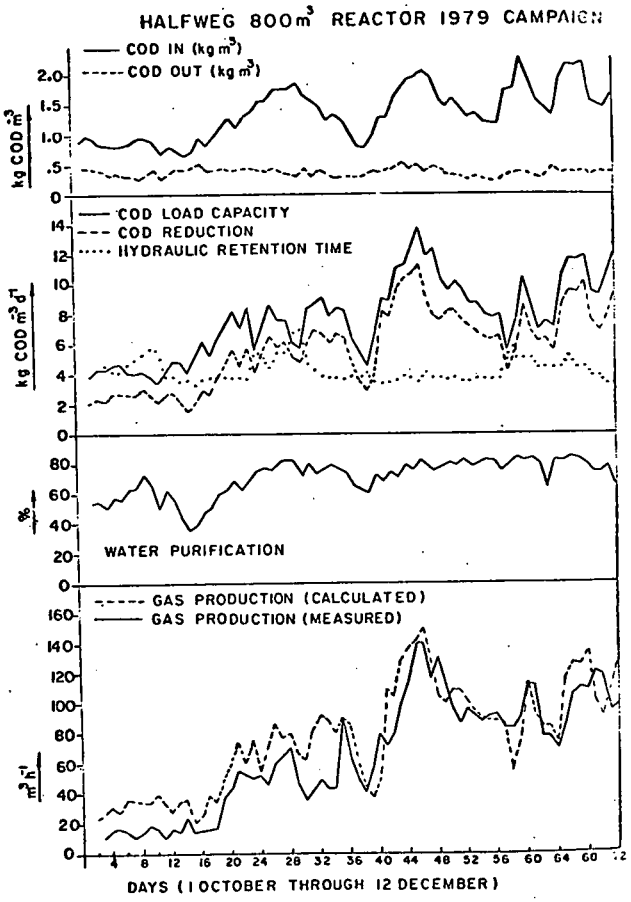


Fig. 3. Purification and gas production parameters for 200 m^3 anaerobic treatment facility at Halfweg for the period of the 1979 beet sugar compaign; the calculated gas production is based on 0.39 m^3 kg COD^{-1}.

converted, the production rate upon which our energy recovery calculations are based. The COD reduction during this period generally was in the range 7-11 Kg per m^3 of reactor volume per day, a figure which has been improved upon by a factor of two with the Breda reactor. Fig. 2 shows results of recent (October, 1979) work with this system. The COD reduction during this period averaged close to 20 kg per m^3 of reactor volume per day, with purification of the incoming COD well exceeding 90%. The biogas yield was mostly in the range 0.4 to 0.6 m^3 per kg of COD converted, with production rates generally about 15 m^3 per hour (9 cfm). The very high incoming COD concentration (30000 ppm) resulted in the necessity for relatively long (40 hour) hydraulic retention times.

Gas production with the 200 m^3 anaerobic system operating on the beet sugar waste stream at Halfweg is equally impressive. Table 3 summarizes the relationship between COD load and gas production at this facility during a one-month period of the 1978 campaign. The total biogas yield during this period averaged 0.4 m^3 per kg soluble COD converted. The methane component was found to be a very rich 86.5% ± 2.4% by volume, or again about 0.35 m^3 per kg COD converted. The soluble COD load reduced was in the range 9.7 to 13.6 kg per m^3 reactor volume per day.

Results with the industrial-scale 800 m^3 reactor at Halfweg are shown in Fig. 3 for the 1979 beet sugar campaign from 1 October through 12 December. The COD reduction load is very low (2 kg per m^3 reactor volume per day) near startup, but gradually increases by day #26 to 6 kg COD per m^3 reactor volume per day and by day #44 to 10 kg COD per m^3 reactor volume per day. The COD purification percentage is about 80% from day #26 on, a lower value than obtained with wastewaters with

more substantial concentrations of incoming COD. Note that in this case the incoming soluble COD concentration averaged only about 1500 ppm.

The total biogas production at the 800 m^3 Halfweg reactor initially was less than the average 0.4 m^3 per kg soluble COD reduced which was observed in Fig. 2 with the same wastewater through the 200 m^3 reactor. By day #35, however, the biogas yield generally equalled that observed with the smaller reactor. A gas production curve calculated on the basis of 0.39 m^3 per COD reduced is plotted on the bottom section of Fig. 3 for comparison with the measured quantity. The methane content continued to range from 80% to 85% throughout most of the campaign.

It is interesting to note in Fig. 3 the extremely short hydraulic retention times achieved during the 1979 campaign with the 800 m^3 reactor. During the latter half of the campaign, the retention time was consistently close to 4 hours. This allowed a wastewater throughput of 4800 m^3 per day (1.25 million U.S. gallons per day) with a very compact reactor of size 800 m^3 occupying a space of only 11.8 m (39 ft) by 15.0 m (49 ft). This small size, of course, offers a degree of economy unmatched in earlier types of waste treatment systems.

ENERGY RECOVERY

For calculation purposes, we can consider a methane production rate of 0.35 m^3 per kg of soluble COD converted within the reactor. The caloric value of the methane could be expected to be in the range 900 to 1000 BTU ft^{-3} or, near midrange, about 34000 BTU m^{-3}. Every kg of COD converted thus produces about 12000 BTU or 0.12 therms.

We can use the 800 m^3 reactor at Halfweg to illustrate the potential for energy recovery. The COD load conversion capacity of this reactor was generally in the range 8 to 10 kg COD per m^3 reactor volume per day during the latter half of the 1979 sugar beet campaign (Fig. 3). The 800 m^3 reactor, therefore, was able to process in total as much as 8000 kg of COD per day which equates to the generation of about 1000 therms (1 x 10^8 BTU) of energy per day. Since 1 gallon of fuel oil contains the energy equivalent of about 150000 BTU, the production of energy from wastewater with this anaerobic system is equivalent to more than 650 gallons of oil per day. With the cost of fuel oil approaching 80¢ per gallon in some parts of the country, the cost savings amount to more than $500 per operating day.

The example given above is conservative to the extent that the 800 m^3 plant is relatively small and the COD load of 10 kg COD m^{-3} d^{-1} does not tax the full capabilities of the system. We have been working on a design for a 2200 m^3 reactor which will treat 25000 kg of soluble COD per day while handling a daily hydraulic load of close to 1,000,000 gallons of wastewater. These flows and COD loadings are fairly typical of many food processing plants. Under these conditions, the energy content of the produced biogas will approach 3000 therms per day, representing a daily cost savings of about $1600. A plant of this capacity operating 320 days a year could produce enough biogas to save more than 600000 gallons of fuel oil each year. The ready availability of such energy from wastewater could, in the future, be the competitive edge to insure a successful business enterprise.

OPERATING FEATURES

In this paper we have highlighted the biogas production aspects of the upflow anaerobic process and its enormous potential for serving as an important alternate energy source. We have also discussed in detail the water purification capabilities of the system which, after all, has been designed first and foremost as a technological advance in waste treatment procedures. We have touched briefly on the unique design of the separator baffles which allows for very short hydraulic retention times and the construction of compact, economical reactors.

This upflow anaerobic sludge blanket process also contains other attractive features which offer advantages in ease of operation. These features have been discussed in detail elsewhere (2,3,4,5) and will only be briefly described here. The process functions in the mesophillic temperature range of bacteriological reactions, which means that the wastewater entering the reactor need only be warmed to "body temperature" - about 35°C. This does not impose a great energy expenditure demand to warm most kinds of food processing waste streams. In fact, effluent streams from many factories have temperatures close to 35°C and, in cases where the water is colder, factories often have low pressure waste steam which can be accessed for heat

exchange purposes.

The upflow anaerobic process has operated effectively through wide swings in pH of the incoming wastewater. Although we quote the pH range 6-8 as optimal for smooth functioning of the process, data have been acquired showing that performance remains high even in the pH range 5-6. Swings of pH somewhat outside this very broad range can be tolerated for short periods. Highly alkaline waters (pH > 9) should not be passed into the system without the capability for buffering or otherwise dosing with acidic substances. Waters from most types of food processing industries routinely fall within the pH range 5-8 except perhaps when equipment cleaning operations are in progress.

Since most of the soluble COD content of the wastewater is converted to biogas with this process, the growth of sludge within the reactor is very slow relative to other types of biological treatment techniques. The CSM experience with sugar beet wastewaters indicates that for every 100 kg of soluble COD converted, only 5 kg (5%) ends up as volatile suspended solids (sludge). This very slow growth increment of sludge greatly alleviates disposal problems. The sludge itself can be used as fertilizer, and investigations into its possible use as animal feed are being pursued. The granular sludge, of course, has excellent settling and handling properties (can be dewatered) and, being in a stable form, is free of objectionable odor.

A final important operating feature of the system is its ability to reactivate with restoration of feed waters. Since the beet sugar campaign (season) at CSM is only for three or four months of the year, the anaerobic system remains in a dormant state for long periods of time with no feed entering the reactor. The sludge is not drained from the reactor during these dormant periods. In fact, no special attention is given to the system at all. Upon startup, the reactors have consistently been found to reach designed operating capacity within a matter of a few days, even after a 9 month period of complete inactivity. The production of useable quantities of biogas is instantaneous with the restoration of the feed. It can be appreciated, therefore, that the process has a good tolerance to underfeeding, and will not be damaged in any way by even moderately long periods with no feed at all.

CONCLUSIONS

The CSM upflow anaerobic process, marketed in North America exclusively by the Joseph Oat Corporation under the tradename "BIOTHANE", represents a breakthrough in biological waste treatment technology. The system is highly resilient to upsets because of its tolerance to reasonable changes in COD loading and pH, and because it operates most effectively within an easy-to-maintain range of temperatures. Sludge production is minimal. Almost all of the incoming soluble COD is converted to biogas rich (80%) in methane content. Recoverable energy in the form of directly-burnable methane produced from an industrial-scale system can save on the order of 1000 gallons of fuel oil per day, the exact amount depending, of course, on the composition and flow of the wastewater. Hydraulic retention times are extremely short thanks to a unique baffling system which serves to separate liquid, solid, and gas near the top of the reactor. The short hydraulic retention times allow for compact installations, suitable even for the most urban of areas. The process produces a purification of the soluble COD load of the wastewater by about one order of magnitude (90%). The upflow anaerobic (BIOTHANE) process is well suited to the waste treatment needs of industries such as sugar refining, potato processing, cheese manufacturing, fruit and vegetable processing, brewing and distilling, grain milling, wine production, and, last by no means least, gasohol production.

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COMPUTERIZED CONTROL OF ENVIRONMENTAL SYSTEMS

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ABSTRACT

This paper examines the actual implementation of two computerized environmental sytem maintainance control centers. Project "A" is a candy manufacturing plant where controlled systems included subfreezing storage, HVAC, and cold storage (40F to 55F). Project "B" is a refrigerated warehouse where environments ranged from subzero(-10F) to battery chargers. Problems, Solutions, Hardware, and Software are discussed.

ENERGY ACCOUNTING SYSTEMS, INC.

Energy Accounting Systems, Inc., Macon, Georgia is a consulting firm that assists its clients to improve their energy efficiency by:

1. Performing an audit of a facility's energy use patterns.
2. Creating a model of the physical and managerial components of the facility.
3. Developing an integrated program of Energy conservation.
4. Implementing this program.
5. Monitoring the plan and advising updates as needed.

1.0 ENERGY: A GROWING PROBLEM

By now, all Americans are aware of the Energy Crisis and while they may not agree upon its true scope, source, or solutions, it is generally agreed that there is serious danger to our economy and the profits of most businesses. The inflation rate has justifiably been linked to this explosion in the cost of energy and all available indicators point to the continuing escalation of cost, dimuntion of supplies, and ever-increasing governmental regulations on energy use. This places a growing strain upon the profits and growth of American business during the forseeable decade. There are no simple solutions at this time.

1.1 GROWTH RATE OF ENERGY COSTS

Energy Accounting Systems' studies of the cost of Energy to its clients show that the cost per MBTU to our average client has grown from $3.06 in Jan 1977 to $7.13 in Jan 1980. Projecting this growth into 1983, we predict that $16.00 per MBTU will be common among medium users. We cannot afford the luxuries of waste or indecision much longer.

1.1.1 ENERGY BILLING TECHNIQUES

The utility companies, in order to protect themselves and pass these rising expenses quickly on to their consumers, have created a variety of billing techniques-- all of them affect commercial users to some degree.

1.1.2 DEMAND CHARGES

Demand is the rate of energy draw that a facility places on the subject utility. The rates and techniques of measurement are complex and severely punish the careless. The demand charge often represents as much as 1/3 of a facility's total energy bill. Demand efficiency studies indicate that a large portion of this charge results from poor power management of environmental systems.

1.1.3 CONSUMPTION CHARGES

Consumption is the actual quantity (in applicable units) of energy that a facility uses in a given period of time. Efficiency studies indicate that as much as 20% of all billed consumption is unplanned, unproductive waste (overhead) that effective management can control.

1.1.4 SURCHARGES AND TAXES

These are commonly unavoidable, but reduction of the waste will reduce the base these are calculated from.

1.2 ENERGY USE IS THE RESULT OF MANAGEMENT

Operating schedules, maintenance, environments, personnel training levels and priorities for capital investments are management decisions that co-author the energy requirements of any given facility. Finer more optimum decisions and controls nearly always

result in reduced energy requirements. Most facilities model their energy use as a continuous flow-feedforward open system. Energy use must be seen as a series of batch processes linked recursively to knowable parameters with a high feedback and of brief duration. Manpower to operate this decision-oriented prototype becomes logarithmically higher in relation to the level of control exercised, therefore it is seldom used.

1.2.1 AUTOMATION IS THE KEY

Historically, good management has recognized the need for operating plans that act upon resources and control events based upon determinable criteria--rather than panic reaction to crisis. In the fields of accounting and production these decisions have long been automated for maximum efficiency: yet in the area of environmental condition maintenance there are few intelligent control systems, and fewer facilities where plans have been structured for the active minute-to-minute control of environments based upon a strategic management plan for these energy intensive devices. All systems that create and/or maintain any environment must be centralized and computerized for maximum efficiency. Environments include all HVAC, refrigeration, production heating and cooling, freezing, lighting, boilers, and the rest of the energy intensive arsenal of environmental systems. Computerized environments save money through a combination of more intimate and accurate physical control and improved management.

1.3 PRODUCTION EFFICIENCY

A facility exists to create goods and/or services and to create PROFITS. The creation process consumes energy under some general rules and this process may be simulated in computer model form and examined for the impact value of modifications. The mathematics are well established.

1.3.1 Energy used in a facility may be described as E_f and is distributed as:

$$E_f = E_p + e_b \qquad [e_b = e_w + e_m]$$
$$(A)\quad (B)\quad (C) \qquad\qquad (D)\quad (E)$$

(A) E_f = Total MBTU , Historic use.
(B) E_p = Physical Process requirements.
(C) e_b = Energy for facility overhead.
(D) e_w = Wasted energy
(E) e_m = That minimum condition needed to prevent damage to the facility , systems, and/or goods within from weather, theft, and et.al.

From these factors we can derive the true efficiency of the facility in BTU/Production units where production units are units of physical production, profit related internal quantities, and/or weather linked elements and parameters. (REF: EAS feasibility studies)

1.3.2 The impact of control and modification of a system can be evaluated by mathematic processes such as:

Reduction of energy use through reduction of operating time of system.

$$E_{p(\Delta)} = E_p \times T_{(\Delta)} \qquad [T_{(\Delta)} = \text{saved Time}]$$

$$E_{p(\Delta)} = E_p \times (t_{(\Delta)} \times .025) \times T_{(\Delta)} \qquad [t_{(\Delta)} = \text{Temp chg}]$$

This evaluates energy saved by changes of temperature for brief periods of time.

1.3.3 Facility Energy use can be reduced, without disturbance to production, significant disturbance to personnel comfort, or major capital investment by:

1.3.3.1 Decreasing non-productive operation.
1.3.3.2 Optimizing temperatures, minimizing variences.
1.3.3.3 Allocation of environment based upon variable production oriented parameters.

1.3.4 SAVINGS ARE PLANNED

A well oriented plan will employ these and other techniques in a game plan that balances costs and gains. Black boxes will not provide miracles-- but good management will.

1.4 MANAGEMENT CREATES SAVINGS

Computers can relate time and production with the real world and give a manager the tool by which he can create a minute-by-minute linkage between the real work world and his planned production strategy. A well-balanced energy strategy could include:

1.4.1 Environments that are maintained only as long as its master profit center is needed.
1.4.2 Environments that are continued unitll the costs are greater than the profits, based upon the master plan for the entire facility.

1.4.3 Environments that are modified to suit change as it occurs--good planning will begin the modification before the external evidence is obvious.

1.4.4 A constant self-generating report that is used to modify the plan and continually update its specifications.

1.4.5 A total allocation map for energy use.

1.5 COMPUTERS ARE TOOLS

The software, hardware, operating instructions, and general capability of any system is only as good as the management model that it operates from, but there are several additional areas where computers can save money. These are best described as non-energy efficiency improvements and include:

Reduced running time of equipment increases expectable life.

Optimized conditions for products, people improve moral, decrease waste.

Automatic monitoring of systems parameters.

Metering of utilities.

Boiler controls

Alternate energy source allocation.

2.0 OPERATING SYSTEMS PROVE PRACTICAL WHEN MEASURED AGAINST ANY YARDSTICK. THEY PRODUCE EXCELLENT RETURN ON INVESTMENTS (ROI) IN A VARIETY OF LOCATIONS.

2.1 PROJECT "A" SAVED 25% IN ITS FIRST YEAR !

Project "A" is a candy manufacturing plant. The physical plant includes 2 large sub-freezing storage areas. Low temperature areas (35°F to 45°F), HVAC for manufacturing plant areas and National HQ Operations plus a complete retail restaurant. In all over 300 tons of refrigeration is controlled in 22 diverse environments.

2.1.1 Significant savings were predicted;based upon a detailed feasibility study the potential for savings was predicted to be about 10% to 12%. This projection proved to be quite conservative.

2.2 The system model indicated essentially a continuous open ended series of non-related steady state environments with crude thermostatic feedback and fixed parameters. It was decided that the system model could be re-configured as a batch span series of non-causal recursive environments maintained by a microprocessor with high feedback and adaptive parameters in most areas. Projection of the impact of this behavior modification on the 22 selected systems indicated they could be operated in the new mode and save overall 10%-12%.

2.2.1 PROBLEMS : IMPLEMENTATION

Problems encountered were minimal, even though modifying control circuitry and techniques in a large variety of environmental systems whose ages varied widely. Control philosophy, in general, was to interface a DISABLE/ENABLE relay into the most sensitive portion of the existing control circuit; test temperatures with analog wide-range sensors; readjust the mechanical systems to maximum effectiveness and transfer the control decisions to the main processor. In order that computer problems could not interfere with production, no existing circuits were deleted and control defaults to the existing manual controls were designed in at the earliest planning level.

2.2.2 Actual wiring was carried out using low voltage class II lines and low voltage sensors. All sensor locations were selected based upon the control strategy and the area being monitored. Conduit was not deemed necessary. Demand levels are sampled at the power meter, and external temperatures are monitored for adjustment in decisions.

2.2.3 Due to the large dispersion of environments, it was decided to provide a full telecommunications link via "MODEM" to a permanent extension and permit control and reports to be exercised using a portable ASCII terminal and local telephone lines. This full Telecommunications feature permitted Energy Accounting Systems to provide a broad range of software support during the preliminary stages of control and precluded the possiblity of negative experiences. All Clients are provided with this on-line support for the first 6 months of operation.

2.2.4 SOFTWARE: SOLUTIONS

The facility is a variable shift/variable load operation requiring considerable tailoring of control strategy. The system controller was interfaced with all environmental conditions by means of extensive analog temperature feedback loops. The actual programs were jointly written with the client and such specialists as were needed to insure reliability and proper control. The controller specified was manufactured by Andover Controls Corp.

2.2.5 TRAINING

All clients of Energy Accounting Systems are trained in the actual coding and programming of their systems. The management of Stuckeys, Eastman, Georgia has exhibited aggressive and effective management of their system and Mr. T. Halaska of Stuckeys is responsible for much of the success in the performance of this project.

2.2.6 STABILITY

Of particular interest to the client has been the exceptional stability of all environments under control, and the reliability of all elements of the completed project. Not one compressor failure has occurred in a controlled system during 18 months of operation.

2.3 RESULTS OF PROJECT "A"

The feasibility studies have proven conservative indeed. Significant savings/cost avoidance have been proven to be in excess of 20% in the first year of operation.

Demand Peaks reduced 137 KW (Plate 3)
Billed Demand Reduced 101 KW (Plate 3)
Total Consumption Red 3,508 MBTU(Plate 1)
Production Efficiency up 10% (Plate 2)

THE ENERGY SAVINGS IN THE PROJECT FOR FISCAL 1979 WAS BETTER THAN 25%!

Total dollar savings for fiscal '79 were $43,508.00 for a Return on Investment (ROI) greater than 100%

2.3.1 STATISTICAL EVALUATION

Plate 6 compares statistically 1977 vs 1979. These results indicate that not only was energy use lower, it was also smoother, more predictable, and has fewer and smaller variations. In all the results here were predicted by the studies that preceeded the project. The entire savings was contained within the waste and overhead area of the use curve.

2.4 PROJECT "B" SAVED 18% IN FIRST YEAR

Project "B" is a refrigerated warehouse. Feasibility studies here indicated a potential of 10% to 12% savings. They have proven accurate.

2.4.1 Systems to be controlled include subzero freezers (-10°F to 0°F), refrigerated storage (+29°F to +60°F), HVAC and an extensive array of battery chargers for motorized lifts. In all 32 environments were selected for control (in excess of 250 tons).

2.4.2 Installation, as in "A", proceeded with no unusual problems. Special care was taken to prevent freon migration, oil dilution, and potential "slugging" under low ambiant conditions.

2.4.3 Low voltage (class II) wiring was selected, low voltage wide range sensors made conduit unnecessary but due to the physical characteristics of the building rigid PVC was used to prevent potential abuse of the wiring harness from weather and the operating environments. An Andover Control Corp. Microprocessor was specifiec, and as in "A", interfaced into the building. Due to strict USDA restrictions it was necessary to use a very intense level of feedback of temperature and demand information. As in 2.2.3, full telecommunications were implemented.

2.4.4 SOFTWARE : SOLUTIONS

The system model has been reconfigured as an integrated unit with discrete responses but high predictive control algorithms and simultaneous causal recursive event control in some areas. Adaptive parameters based upon time and demand level are being used. The facility is a three shift high volume operation where temperatures are critical and must be in compliance with strict governmental regulation. All programs have been written jointly with the client and are designed in such a manner that temperatures are paramount. Defrost controls are being integrated into the control scenariae at this time, based upon humidity sensor information.

2.4.5 DEMAND CONTROLS ARE MANDATORY

The utility treats demand peaks severely and for a 30 minute occurrence the client would have to pay 95% of the peak for 11 months. At the Jan 1980 rate this could become significant. EXAMPLE: if a 50KW one time event lasted 30 minutes it would cost--

PLATE 1
GROSS CONSUMPTION

1977 VS 1979
PROJECT " "

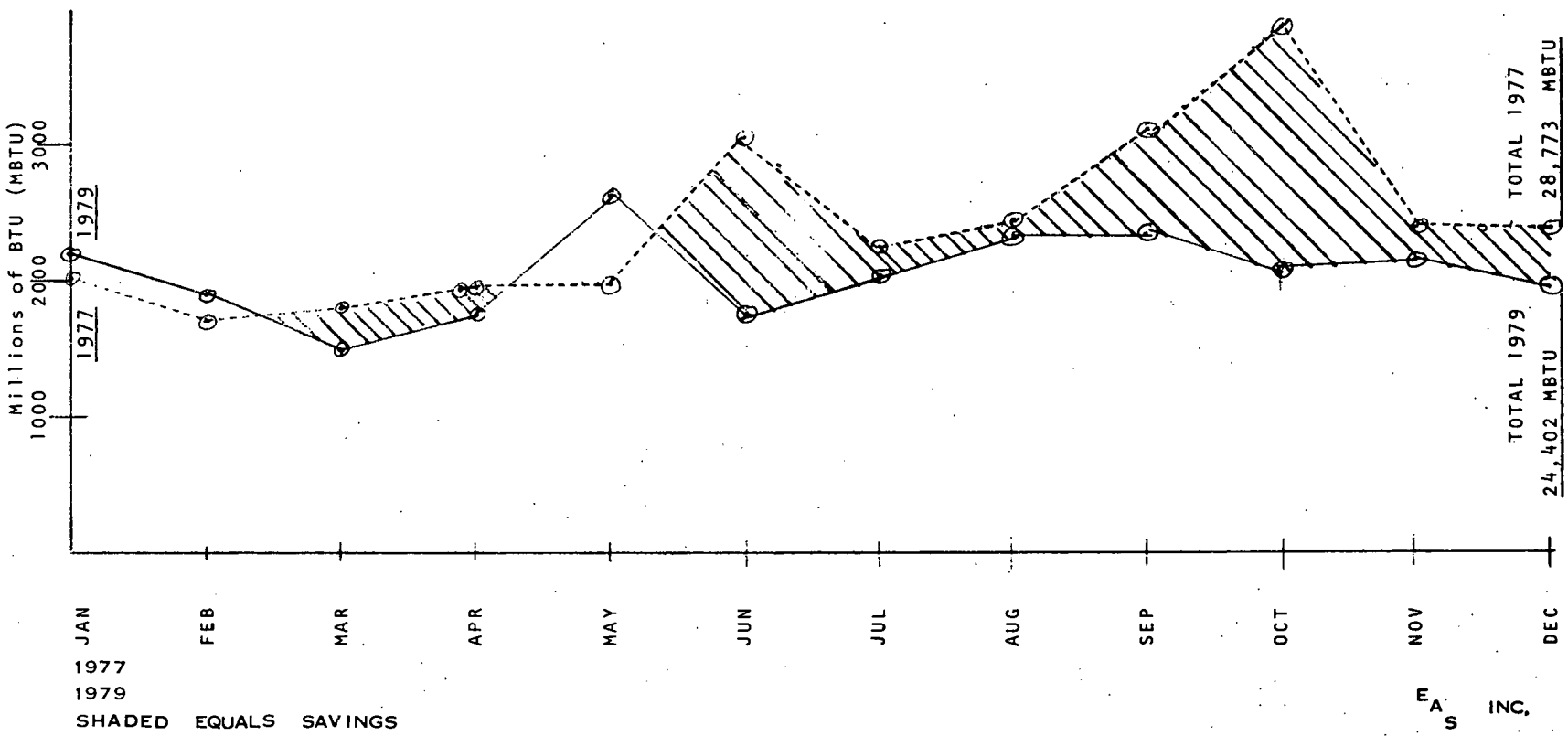
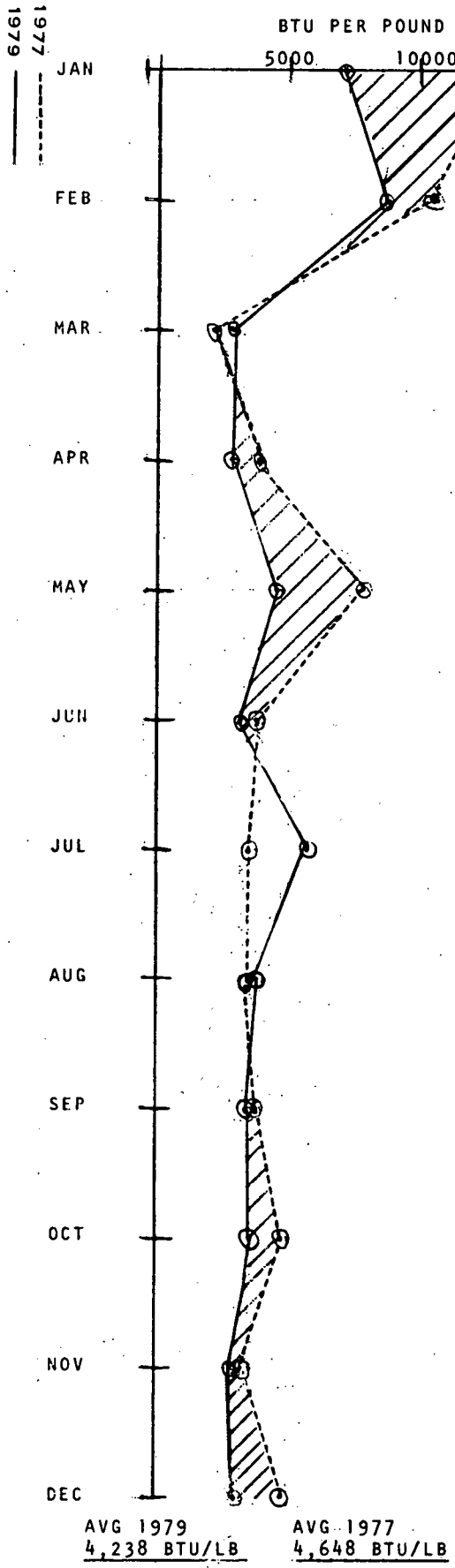


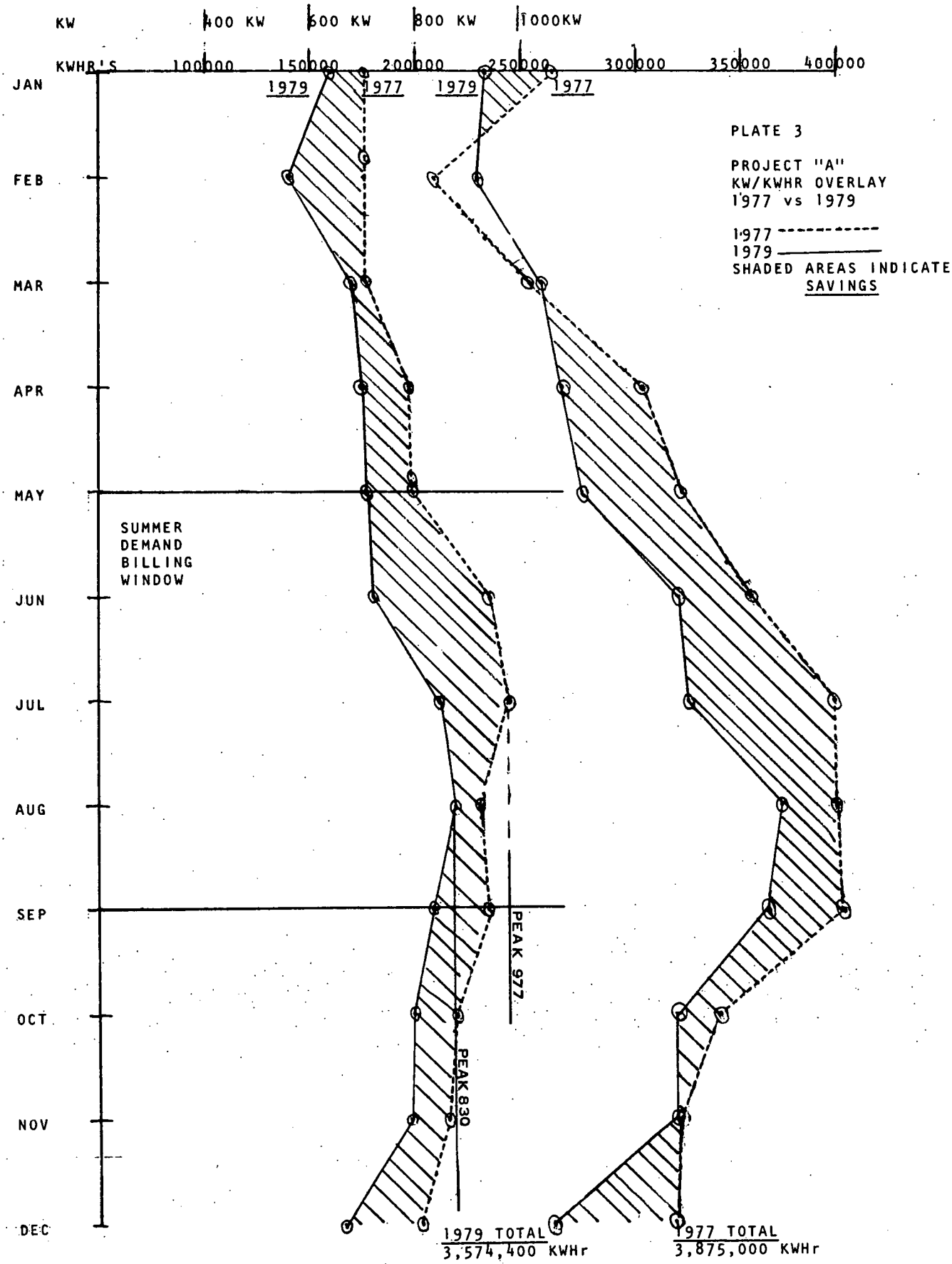
PLATE 2
PROJECT "A"
BTU/LB

PRODUCTION
EFFICIENCY

SHADED AREAS INDICATE SAVINGS.



ENERGY ACCOUNTING SYSTEMS, INC.



Energy Accounting Systems, Inc.

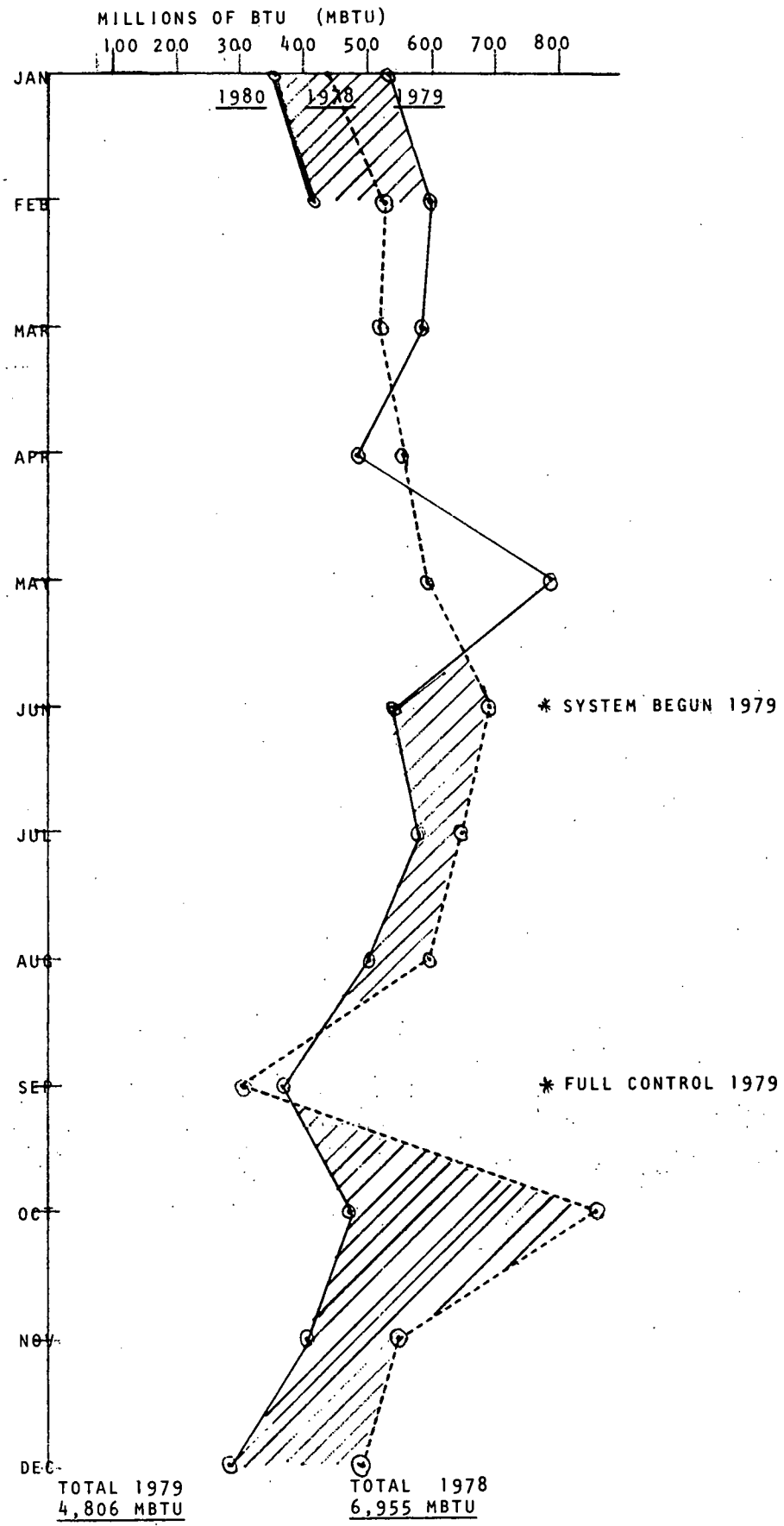


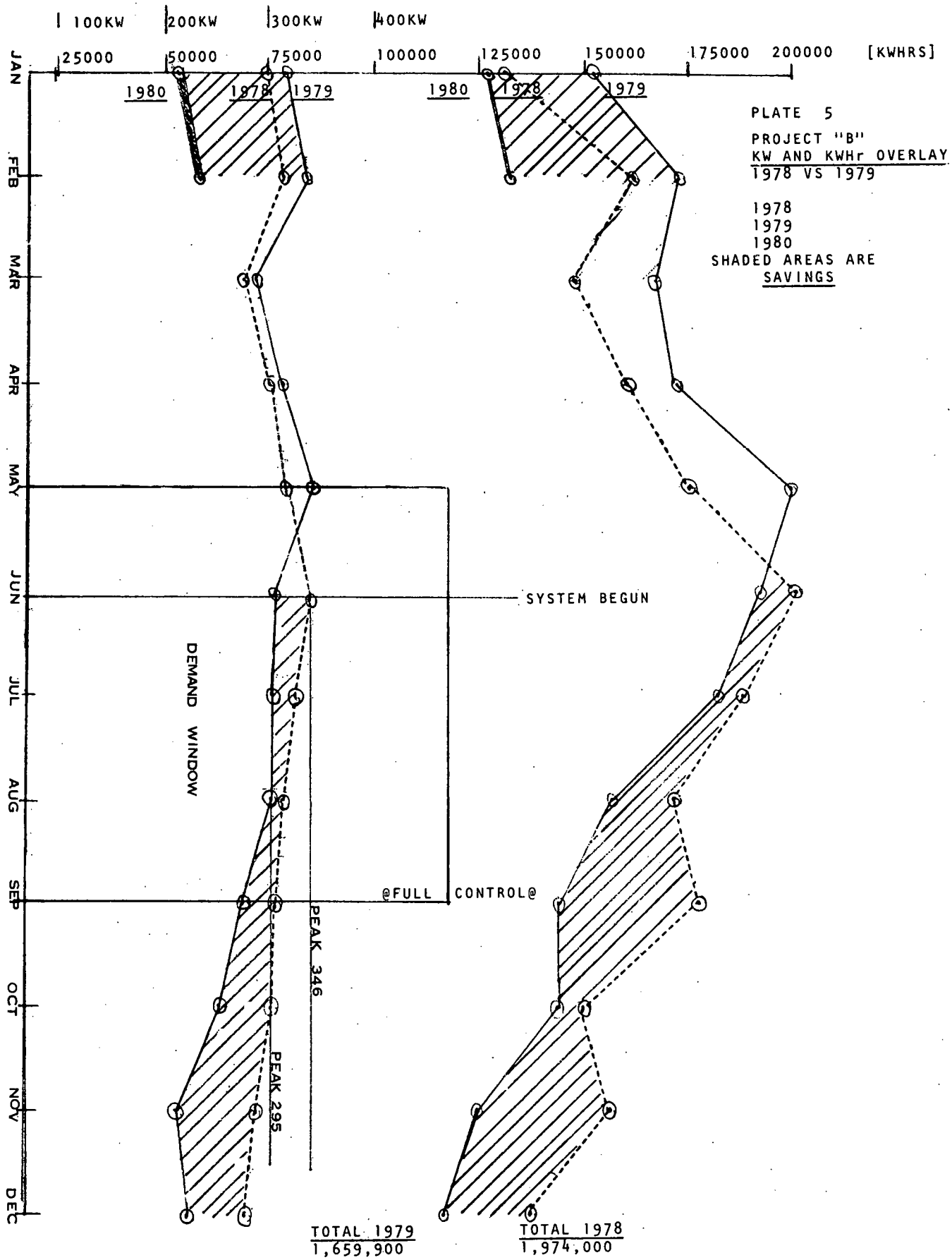
PLATE 4

PROJECT "B"
GROSS CONSUMPTION
(MBTU)

1978-1980

1978
1979
1980
SHADED AREAS INDICATE
SAVINGS

ENERGY ACCOUNTING SYSTEMS, Inc.; Macon, Ga.



ENERGY ACCOUNTING SYSTEMS, INC. MACON, GA.

PLATE 6 - STATISTICAL ANALYSIS OF PROJECT "A"

Full analysis of actual performance (USE ENERGY IN MBTU) of project "A".

ENERGY ACCOUNTING SYSTEMS SUMSTAT RUN ON
STUCKEYS 1977 TOTAL CONSUMPTION 3/20/80

INPUT VALUES WERE:
2042.2000000
1696.5000000
1746.6000000
1915.8000000
1980.3000000
3026.4000000
2282.3000000
2417.6000000
3091.7000000
3855.8000000
2394.7000000
2323.7000000

:NUMBER OF OBSERVATIONS	12
MEAN OF VALUES	2397.8000000000
VARAIANCE	372550.00000000000
ESTIMATE OF POP. VARIANCE	406418.0000000000
STANDARD DEVIATION	610.36900000
ESTIMATE OF POP.STD. DEV	637.5090000000
ESTIMATE OF ABSOLUTE DEVIATION	466.7170000000
MEASURE OF RELATIVE SKEWNESS	1.036800000000

ENERGY ACCOUNTING SYSTEMS SUMSTAT RUN ON
STUCKEYS TOTAL MBTU 1979 3/20/80

INPUT VALUES WERE:
2167.3000000
1893.4000000
1499.2000000
1735.2000000
2548.9000000
1750.0000000
2017.7000000
2322.4000000
2326.6000000
2057.8000000
2143.6000000
1940.4000000

:NUMBER OF OBSERVATIONS	12
MEAN OF VALUES	2033.5300000000
VARAIANCE	79074.700000000000
ESTIMATE OF POP. VARIANCE	86263.3900000000
STANDARD DEVIATION	281.20200000
ESTIMATE OF POP.STD. DEV	293.7050000000
ESTIMATE OF ABSOLUTE DEVIATION	227.5500000000
MEASURE OF RELATIVE SKEWNESS	-0.058643400000

50(KW) X .95 X 11(MO) X 7.70 (PKW)=
$ 4,023.23+tax

To avoid this possibility, an aggressive demand control algorithm based upon the predictive law of the hypotheneuse has been written into the system and to date effectively reduced the facility demand to below any historic record (10 yrs). That same algorithm is used in all projects. Plates 3 and 5 illustrate the result and its effectiveness under the most demanding conditions.

2.4.5.1 Power outrages such as lightning, brownout, and local interruptions are common in the area, and a special control response was configured to handle them. Since its application, no damage has occurred in a controlled system.

2.6 RESULTS OF PROJECT "B"

The feasibility studies have proven to be accurate. Significant savings/cost avoidance have risen to be in excess of 12% in the first year of the project.

Peak Demand Reduction of	80 KW (Plate 5)
Billed Demand Reduction of	30 KW (Plate 5)
Consumption reduced	2,245MBTU(Plate 4)

Total Energy Savings of 18%. and Demand is lower than at any period in 10 years.
The ROI of this project is 62%(not including tax credits, investment credits, or allied internal configurations)

3.0 SUMMARY

A well planned computer control system can save significant amounts of money and energy even under difficult conditions. A proper and complete system can be implemented while providing an excellent ROI (Please note that the tax advantages are considered separate and apart from the energy advantages and Returns)
Project "A" has generated an ROI in excess of 100%, and Project "B" is providing an ROI of 62%. When all tax advantages, and future benefits are considered, a computer control system provides an excellent investment opportunity for prudent business managers.

PLANT ENERGY-COST-OPTIMIZATION PROGRAM (PECOP)

A. M. Robinson

Taft Plant, Louisiana
Union Carbide Corporation

The Plant Energy Cost Optimization Program (PECOP) is a Management System designed to reduce operating cost in a continuous operating multi product plant by reviewing all cost factors and selecting plantwide production schedules which are most economical and efficient.

Key requirements include production units and energy systems that are operating below full capacity, storage for production inventory, economic data on fuel and electrical costs, production plans and energy efficiency ratings of various components. The requirements are integrated via alternative operating techniques such as block operating, adjusting maintenance schedules and coordinating startup and shutdown schedules to optimize operating costs.

INTRODUCTION

Today's petrochemical plants usually consist of several processing units. Energy sources can be external to the plant, plant utility converted, and production unit generated, or a combination of all three. Raw materials for the various units are both externally supplied and internally produced. The plants produce a multitude of products, meeting various demand schedules and are shipped by varying modes.

Managing the plant energy in the most economical manner demands a systematic approach. I would like to introduce you to an innovative new plant management system. It is called PECOP. It is a new Union Carbide Chemicals and Plastics management tool which is available to help your plant. The name stands for Plant Energy Cost Optimization Program.

PECOP is designed as a system that integrates three important elements, they are, utilizing production scheduling flexibility which may exist for your plant production units, using the efficiency which may be inherent in your various energy systems equipment, and employing production unit operating rates in a way to reduce costs. With the system, PECOP additionally emphasizes and considers material efficiencies and environmental protection costs. With the system you can have a one-step management tool for analyzing production and energy costs and preplanning operations to save money and reduce operating costs at your location.

JUSTIFICATION

With more than a year of Taft plant experience with PECOP, we found that our management system has given us new concepts for unit production planning and operations. As a result, we have started following some new economical production planning practices automatically, instead of waiting for PECOP to point out this more efficient way. Results are sometimes difficult to measure, but we estimate that PECOP is saving $500,000 a year at Taft in reduced operating costs. When the system is properly utilized, we feel certain that this dramatic savings

can be replicated at any similar production plant.

SYSTEM PREREQUISITES

To see if PECOP would fit your location let's look at the seven basic prerequisites to make PECOP a workable management system at a location.

You must have production units which are running at less than maximum. If every unit is running flat out and you are sold out and trying to keep up with sales, PECOP won't work for you.

Besides needing production below maximum capacities, PECOP also requires that energy systems be operating at less than its maximum capacity. Again, the management system requires some scheduling flexibility which is not possible if you are "sold out" on steam or other energy needs.

Another requirement is that storage must be available for products. Without this, you again lose the system's flexibility. Besides storage capacity, PECOP also requires establishing minimum and maximum inventory levels for products. Those levels become key management benchmarks in your PECOP production planning.

The fourth requirement is that there must be economic data available on your energy costs, including the economics of various fuels and electricity costs.

It is also important to have and utilize monthly production plans, either monthly six-month plans or monthly two-month plans.

Also, PECOP requires that the MMBTU per thousand pounds of production be plotted for units at various production rates. In other words, there must be established curves showing the relationship of BTU's to pounds produced at various rates. This efficiency profile is also needed for energy systems. Each component should be plotted in its individual and relative energy efficiency at varying production levels.

The system requires knowledge of the interrelationships and flexibility of the utility and production systems. In a multi-product plant, this knowledge does not always reside with one person or group. Deliberate managements steps are frequently required to facilitate this requirement.

In summary these seven are the prerequisites for a successful plant PECOP program.

Production Units Operating Below Capacity

Energy Systems Operating Below Capacity

Product Storage Available

Fuel and Power Economic Data

Monthly Production Plans

Data from Production Units on Utility Use

Knowledge of Interrelationships and Flexibility of Utility and Production Units

Each was keyed to either production flexibility at the site, such as having storage space, or not operating at full capacity; or each involved some basic information about how the plant really works, including data from product inventory to unit efficiencies at varying production levels. Together, these seven requirements are plugged into the PECOP management system to give us a working profile of how you can adjust plant production and make significant savings in operation and energy costs at your location.

KEY TECHNIQUES

To better understand the nuts and bolts of PECOP, let's look at some of the key techniques we use with the system.

One important technique is block operation. Many plant production units run most efficiently near full capacity and have unfavorable turndown ratios. By unfavorable turndown ratio we mean that energy consumption per pound of product increases as production rate decreases. Block operation represents a big

change from the "good old days" when most petrochemical operations were continuous. Historically we have devoted effort to keeping the units on line and avoiding the wear and tear and other problems with startups and shutdowns. But the realities of today's energy costs dictate that we must improve our efficiencies, and block operation is a highly effective way to accomplish that. Quite simply, block operation means we run units with favorable turndown ratios at maximum capacity whenever possible, and then shut them down when we are within our accepted product inventory levels. This system presumes some of the PECOP prerequisites like not needing to operate at full capacity all the time; having storage for products; and others. While block operation is a tool, it is important to remember that PECOP is still the overall management system. For example, the PECOP system will be used to identify all the key cost factors in making the decision, including product demand, storage, maintenance, startup and shutdown, production unit, and energy efficiencies. After all the facts are laid out with PECOP we can mix and match our production needs to develop an energy efficient operation schedule which allows us to produce the required volumes of products at the lowest possible energy cost. A good illustration of the need for this coordinating technique occured at one plant. With a PECOP analysis we discovered a unit that would autonomously shut down on their own schedule. The unscheduled shutdown created a steam imbalance which resulted in venting. With PECOP, though, we can predict, pre-plan, and coordinate a plantwide production schedule that lowers our operating costs.

Another factor we consider is the fuel source. Electricity, gas, fuel oil, and other fuel costs can vary all over creation depending on the source, volume, and numerous other pricing and cost factors. PECOP, as a system, is designed to plug in these cost variables in fuel sources and guide us to the most economical mixture to meet our overall production needs. This variable in production planning is taking on increased importance, too, as energy costs continue to increase for all of our plants.

Another integrated factor in PECOP decision-making is the utility spinning and boiling reserve for energy systems. If we operate several units and put a demand on energy systems that reduces the reserves below a given level it must be factored in as an additional risk.

We also must look at energy systems efficiencies. We save the most money when we pre-plan and schedule the energy systems demand to utilize the most efficient operating rates.

In the same way, we also review unit production efficiencies for the best economy in scheduled operations. All of these areas become built-in factors with the PECOP system.

SYSTEM USE

PECOP use consists of the following action steps:

Identify the problem or opportunity area. This can be either a potential, future problem or existing problem.

Determine the means for improvement either thru production flexibility or energy flexibility or re-scheduling of resources.

Consider impact on other areas such as environmental, distribution systems, maintenance, etc.

Determine if the net results are favorable.

Take action thru a coordinating function to implement the change, continue as is, or review another alternative.

To better understand, let's make a step-by-step review of how a PECOP system could be used at your

plant. PECOP is a money saver by reducing the waste of energy in the plant. The program is designed to save in the critical areas of:

Vented Steam

Vented Fuel

Fuel Cost

Material

Environmental

Maintenance

The system analyzes and compares costs in these key areas to guide us to economical operation decisions. PECOP helps identify these cost areas for us. It is a decision making tool for more efficiently planning and managing our production activities. These key factors for full costs review include:

Production Material Efficiencies

Production Energy Efficiencies

Idle Cycle Costs

Electric Utility Costs

Internal Raw Material Costs or Availability

Shutdown and Startup Costs

Environmental Costs

Product Inventory Costs

Extra Freight Costs

The key is to provide a systematic management analysis tool which allows us to identify all of the real costs involved in producing our products, and then pre-plan a production schedule which provides the best plant-wide production economy. As you may have guessed, planning is at the very heart of the PECOP system. Production plans are essential. With growing energy costs, we really don't have a choice. With PECOP you can have a planning tool which provides a systematic review of potential production costs. PECOP can work for you on three planning levels.

At the first level, as your monthly production plan is developed, review it long-term through PECOP for possible waste. Then you can coordinate and master-plan plantwide production schedules to eliminate the waste and save money.

Now, when you face adjustments, with a unit going up or down for various unplanned reasons, PECOP works on a second level. It shows you short-term opportunities in scheduling.

And finally at the third level it's a real time tool. Look at today's operations. You can identify energy wastes and make a sound economic judgement while considering all the key cost factors.

On all three levels, PECOP produces its most dramatic results simply in giving us a new perspective on our business. Instead of responding from old operational procedures, we have a detailed review of all the key elements to tell us the dollar consequences of our decisions. The PECOP experience at Taft showed that we quickly started discovering new and more economical ways of managing our business. Techniques like block operations, adjusted maintenance schedules, and coordinated planning between production units have now become incorporated into our new and more profitable "routines". For Union Carbide's Chemicals and Plastics operations at Taft, it is a lot of large and small decisions that net us an estimated $500,000 a year operation improvement.

Quite simply PECOP is a new management tool which reflects the energy cost demands of running a modern petrochemical complex. Cheap energy and outdated operating practices are rapidly dropping by the wayside. We must all work together in developing and refining the most cost-effective ways of running our businesses. If your plant operating conditions are right, PECOP can be an effective and profitable management system to help at your location.

PECOP ECONOMIC FACTORS

	FACTOR	SUB FACTORS	*	
Plant	Production	Additional Production		
		- Material efficiency		
		- Energy efficiency MMBTU/MLB at various rates		
		- Idle cycle cost		
	Maintenance Engineering Distribution	- Facilities - equipment		
		- People		
		- People		
		- Facilities		
		- Transportation equipment		
	Internal Raw Materials	- Source		
		- Quantity		
	Energy	- Steam		
		- Electricity		
		- BFW		
		- Condensate		
		- N2		
	Startup & Shutdown	- Energy		
		- Material efficiency during startup & shutdown		
		- Maintenance overtime		
		- Wear & tear value		
	Environmental	- People		
		- Facilities		
	Laboratory	- People		
		- Facilities		
	Computers	- People		
		- Facilities		
	Safety	- Personnel		
		- Equipment		
Inter	Inbound Products	- Freight Cost		
		- Packaging Cost		
	Outbound Products	- Freight Cost		
		- Packaging Cost		
	Inventory Costs	- Cost of Terminals Storage		
		- Cost of Carbide Storage		
	Cost to Other Locations	- External UCC cost		
		- Other UCC Plant Costs		
		- UCC Plants Effect on Other Plants		
External	Customer	- Loss of Order		
		- Loss of Business		
	Raw Material Supplier	- Failure to Supply Contracted amounts in take or pay contract		
		- Failure to take Contracted amounts		
	Environmental & Safety	- Freight cost		
		- Potential Fines		
		- Potential Plant Shutdown		
		- Image Loss		
		- Potential Liability DOT etc.		

* Check if not applicable

Figure 1

This sheet serves as a reminder of all the economic factors and a checkoff sheet.

The following examples have been analyzed using the economic factors sheet, but have been reduced to only the applicable information.

Example 1

200 psi steam was being vented from a long header because of 200 psi steam header pressure swings. The header swings were being promoted by various users and producers. In order to operate some vacuum jets on a distillation system on the end of the header, pressure had to be maintained at a consistant level that caused venting. Options were examined to reduce the venting. A unit with a large steam turbine compressor was requested to adjust variable steam to increase condensing on the turbine. This decreased the energy efficiency of the turbine by putting more heat to cooling water but the venting was stopped and the header pressure was maintained with no venting. Before this action was taken the following PECOP analysis was made.

By stabilizing the header pressure and increasing efficiency of the vacuum jets $500/day could be saved in material efficiencies. The turbine compressors efficiency decreased by $833/day. By condensing steam and increasing heat to the cooling water the steam venting was reduced by $1,627/day.

In summary:

Problem - Steam venting

Cause - 200 psi steam header pressure swing

Economic Factors -

Material efficiency improvement $500/day

Compressor efficiency decrease $833/day

Vented steam reduction $1,627/day

Results -

Raw Materials	$500/day
Compressor efficiency	$833/day
Steam	$1,627/day
PECOP Savings -	$1,294/day

Example 2

A liquid residue burner in a boiler was taken out of service. During this period the liquid residues were being burned on a ground burner that had no heat recovery. If the residue burner was not completed that day residues would be burned on the ground burner for a four (4) day holiday period.

Options were examined to reduce the loss of this heat value. Instrument maintenance overtime was selected.

A PECOP analysis showed that $800/day in fuel value was being expended. Instruments maintenance overtime would cost $160.

In summary:

Problem - Wasted Fuel

Cause - Ground burning residues

Economic Factors -

Residue Fuel Savings $800/day (4 days) = $3,200

Overtime Instrument Labor -- 2 men X 4 hours @ $20 = $160

Results -

Fuel savings	$3,200
Labor loss	$160
PECOP Savings -	$3,040

Example 3

A boiler dearator was scheduled to be shut down at low steam demand to make repairs so it could accept condensate. A spurt in sales for a production unit made an early startup of the unit desirable. With the unit running the total steam demand indicated not taking the dearator down. Wasting condensate was balanced against loss in sales.

Loss of business was considered to be six (6) days of production worth $140,000. Loss of condensate until all production schedules would allow the dearator to be taken out of service amounted to $3,241. The dearator was rescheduled.

In summary:

Problem - Condensate loss

Cause - Production schedule conflict

Economic Factors -

Loss of business--six days of production = 1MMLB. 1MMLB X $.14 - $140,000

Condensate loss--.720MGAL/hr @ $2.50/MGAL for 2½ months - $3,241

Results -

Variable Margin	$140,000
Condensate loss	-3,241
PECOP Savings -	$136,759

Example 4

In this example, an opportunity to use an available low cost fuel source was taken. The plant had two fuel contracts at widely different costs. Because of various unit outages, the low cost fuel was not being used to the maximum amount. This fuel would be lost if not taken within a given time period. A production unit was rescheduled to start up by requesting early completion of a raw material supply system. In rescheduling the unit it was also determined that with the unit running an environmental department NaOH usage could be prevented because of the caustic wastes from the unit.

A PECOP analysis showed by rescheduling the production unit, that fuel cost savings of $2,330/day were possible, and saving of NaOH usage by the Environmental Department was $2,000/day. Also, no maintenance overtime was required and inventory level restraints were not exceeded.

In summary:

Problem - Under-utilized inexpensive fuel

Cause - Demand/supply imbalance

Economic Factors -

Fuel lost savings $2,330/day

EPD NaOH usage reduction $2,000/day

Revise maintenance schedule = 0

Results -

Reduced fuel costs	$2,330/day
Reduce NaOH usage	$2,000/day
PECOP Savings -	$4,330/day

Example 5

In this case the shutdown of a low pressure steam user during a period when operation of another unit producing low pressure steam was necessary, this caused an increase in production of low pressure steam. Several alternatives were evaluated to minimize vented steam.

An earlier shutdown would cause lost sales. A delay in the shutdown would result in material loss efficiency because of catalyst delay. A reduction in production of the second unit to put steam in balance would cause a situation where material would have to be bought instead of made.

The situations we faced was a choice of losing dollars because of venting steam or losing dollars because of lost sales or material efficiencies. The emphasis is on total dollars lost to the company.

In summary:

Problem - Vented steam

Economic Factors -

Earlier shutdown, lost sales - $2,300M

Later shutdown, with catalyst delay - $180M

Reduce production in second unit to reduce venting - $220M

No change -- $70M

PECOP Solution -

Take shutdown as scheduled

Example 6

This example involves two production units that use a byproduct from another unit to process their material and then vent the remaining byproduct to boilers as fuel. A boiler at one end of the plant had to be taken down for oil burning revisions. This boiler could use the byproduct as fuel direct, while other boilers could only use the byproduct vented from the operating units. The byproduct thus had to be moved thru the two units who had to be operating to move it to other boilers. The solution involved scheduling the two units to run during the period.

In summary:

Problem - Vented fuel

Cause - Production schedule conflict

Economic Factors -

Vented fuel reduction $3,100/day

Production schedule change -- 0

Results - PECOP savings = $3,100/day

WHY ENERGY AUDITS AREN'T ENOUGH; AN ENERGY MANAGEMENT SYSTEM IS REQUIRED

Arthur J. Haft
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ABSTRACT

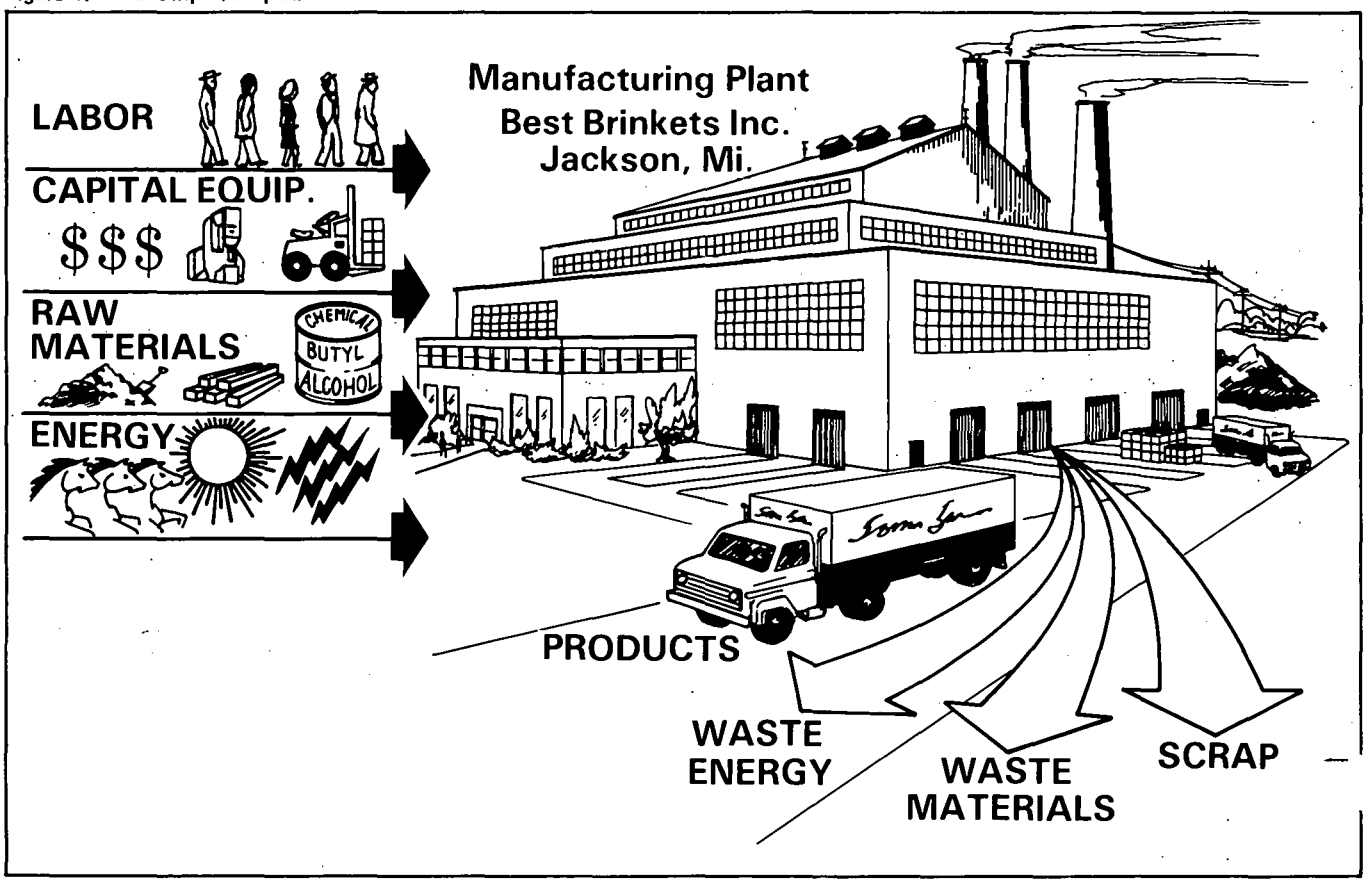
An evaluation of the energy systems in a plant can be accomplished by different techniques which require different levels of effort. Three alternatives are described: Rational Analysis, Energy Audits and Energy Management by Utility Systems Metering. A progressively greater investment in time and funding is required; however, the results yield more information and greater accuracy about energy usage. It is recommended that the step beyond Energy Audits, an Energy Management System, be taken. The Energy Management System approach is worthwhile, and the additional time and funding will be returned in energy cost reductions.

INTRODUCTION

Plant energy coordinators have been given the challenge of providing adequate energy supplies and keeping energy costs to a minimum, both now and in the future. To achieve these objectives, most coordinators have completed what we will call Rational Analyses and Energy Audits, but have not taken measures to introduce an Energy Management System into the plant. A description of Rational Analysis, Energy Audits and an Energy Management System is given along with the benefits of each technique. Recommendations are made to proceed with installing an Energy Management System.

A typical plant with the necessary inputs and outputs is found in Figure 1. To keep the cost of products to a minimum,

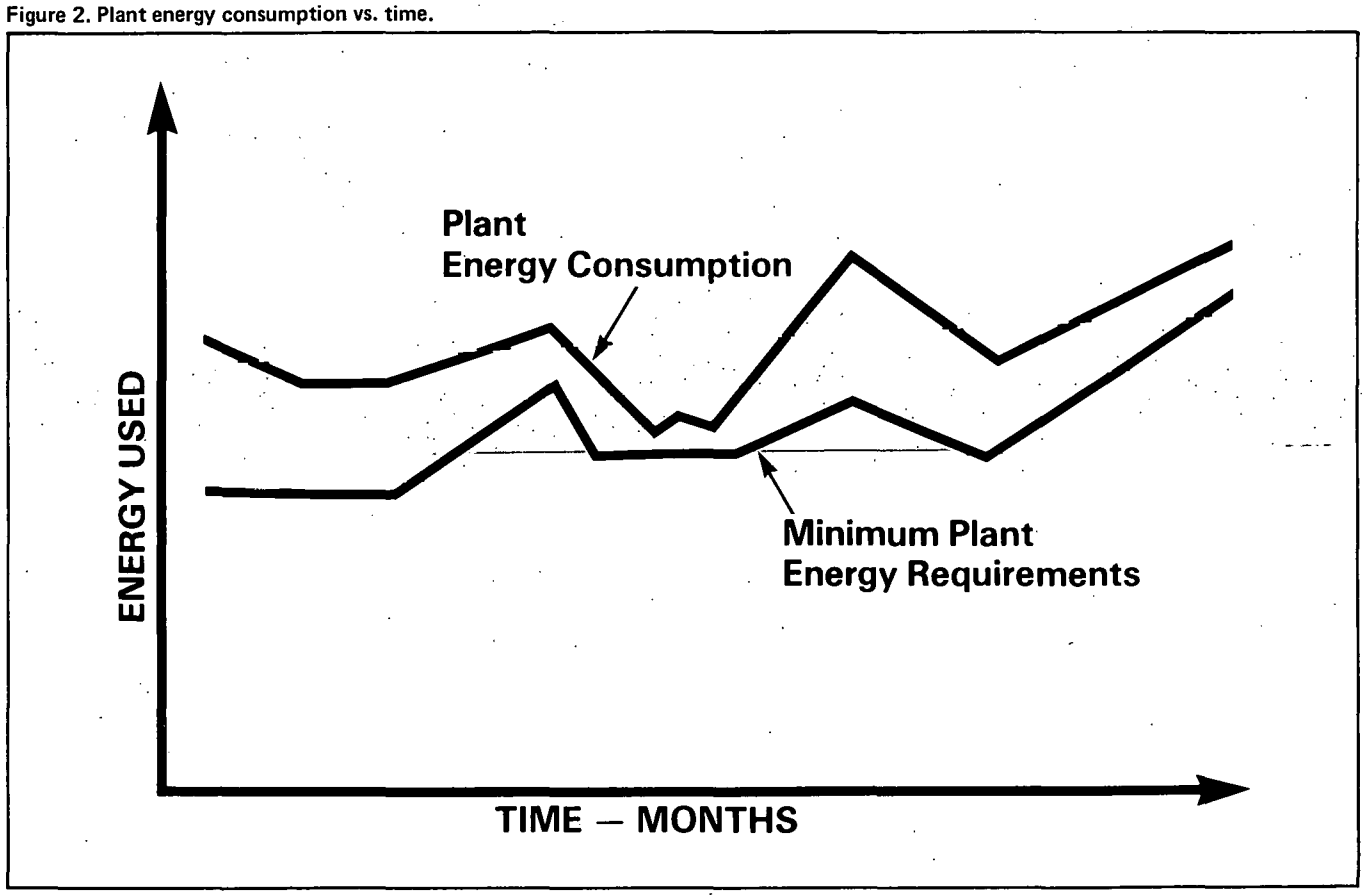
Figure 1. Plant input/output.



it is necessary to minimize both the input costs and reduce waste energy, waste materials and scrap rate. Labor costs are managed by production engineers and industrial engineers. Records of man-hours expended are watched carefully and attempts are made to keep them to a minimum. Capital equipment and raw materials are purchased competitively at the lowest possible price by purchasing agents. Energy costs, now that they are becoming a significant portion of product cost, are beginning to get the same attention. Assignment of an energy coordinator to monitor energy costs, reduce them, and provide adequate future supplies has been the first measure taken to managing energy utilization. The energy coordinator proceeds with Rational Analyses and Energy Audits, but the program doesn't usually include an Energy Management System.

Controlling and reducing energy consumption in a plant is accomplished by comparing present energy consumption to minimum requirements. Graphically, the situation is described in Figure 2. The minimum energy requirements vary as a function of time and production, and energy consumption also varies as a function of time, always exceeding minimum energy requirements. Our objective is to reduce energy consumption consistent with production requirements and maintain this energy reduction on a long-term basis. To initiate the plant energy reduction program, a Rational Analysis is required.

Figure 2. Plant energy consumption vs. time.



RATIONAL ANALYSIS

The quickest and lowest cost method of controlling a plant's energy use is a Rational Analysis. It is accomplished by:

- Evaluating existing fuel, water, and electricity bills.
- Checking metered variables — such as steam flow, kWh (electricity), gas flow, compressed air and water.
- Performing calculations using records, metered information and engineering judgment.
- Making energy allocations based on standards.

A Rational Analysis is conducted by the plant energy coordinator on a monthly basis. He reviews energy use within the plant based on all information available and without performing additional testing. Records of energy use are kept on a monthly basis and recorded. In this manner, an indication of energy consumption trends and patterns is revealed.

Since only gross energy information is known, a distribution of energy use to specific areas within the plant is accomplished by energy allocations. Every manufacturing plant is functionally

subdivided. A chemical plant may have divisions such as raw material storage and preparation, reaction and distillation, purification, solvent recovery, and storage and shipping. Typical subdivisions at a metal stamping plant might be raw materials receiving and storage, machining, heat treating, testing and assembly. Figure 3 indicates how a metal machining plant is functionally subdivided. Regardless of how the plant is subdivided, each of the functional subdivisions will have a number of energy users and should be charged for its energy use. Energy allocation is the method whereby utilities such as the fuel, electricity and steam purchased by the plant are assigned to the subdivision that ultimately uses the energy in one of its final forms. Energy allocations in a plant can be made by using the following:

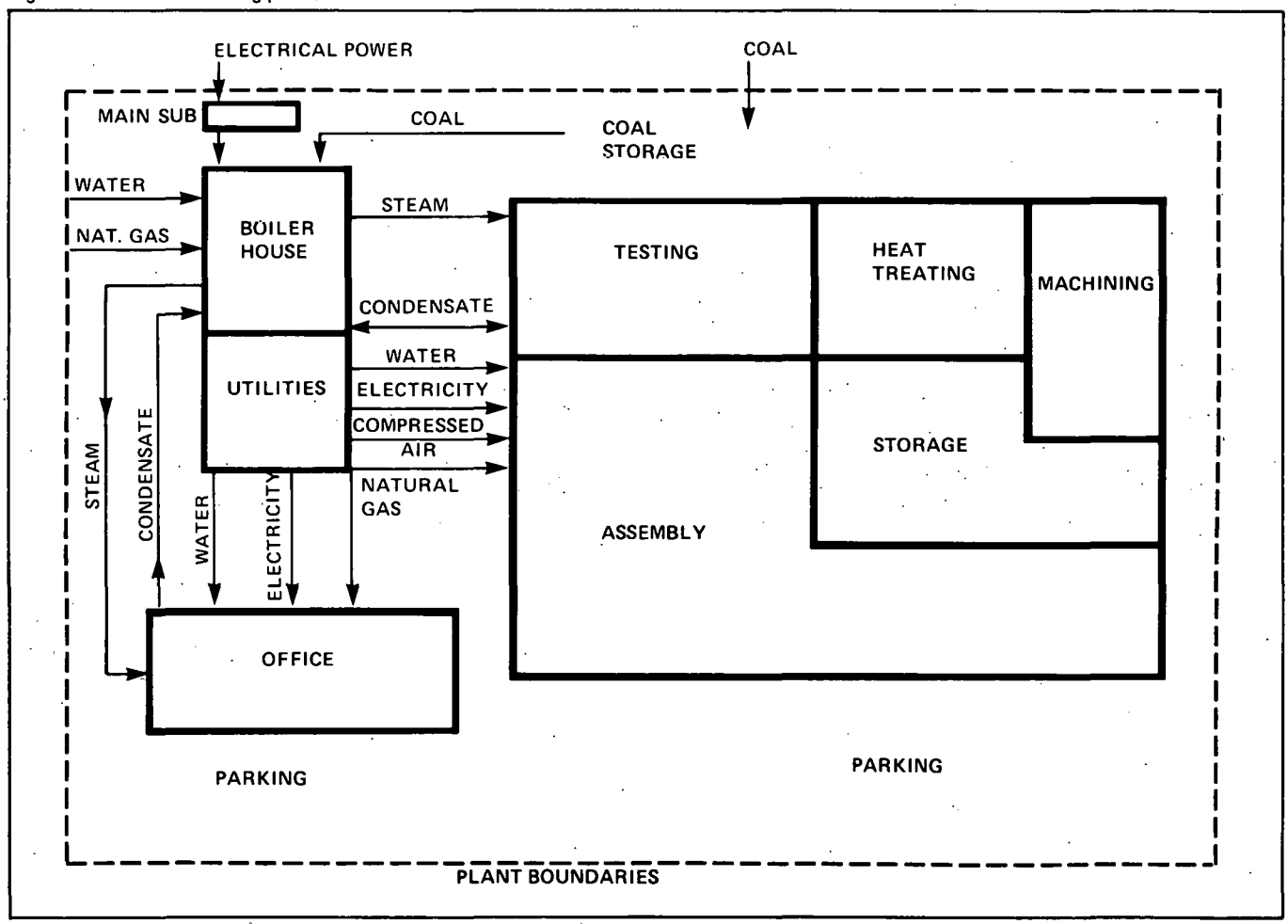
- Floor area – e.g., for heating, ventilating, A/C and lighting.
- Production output – quantity, weight, size and rate.
- Fuel capacity of burners.
- Installed horsepower of motors or drives.
- Engineering analysis of equipment/process.

Allocations determined by Rational Analysis are theoretical and oversimplified, in many cases to a point where results are meaningless. On a monthly basis, the fuel and electricity bills are split up according to allocation formulas with the cost of energy wasted by Department X allocated proportionately to all of the other departments as well. This can result in energy conservation efforts of Department Y not being credited to Department Y. However, it is a method of allocation and should be used as a first step in setting energy standards and energy efficiency goals for each department. It also permits the energy coordinator to understand energy use within the plant and uncover energy conservation opportunity projects. It is the lowest cost method to manage and control energy in a plant and will require two man-days a month of an engineer's time to successfully implement a Rational Analysis program. Rational Analysis, as a method of controlling energy use in a plant, is only viable for small manufacturing plants. The costs are minimal, but so are the results.

ENERGY AUDIT

To obtain more detailed energy information in an industrial plant, an Energy Audit is required. It is an in-depth "snapshot"

Figure 3. Metal machining plant.



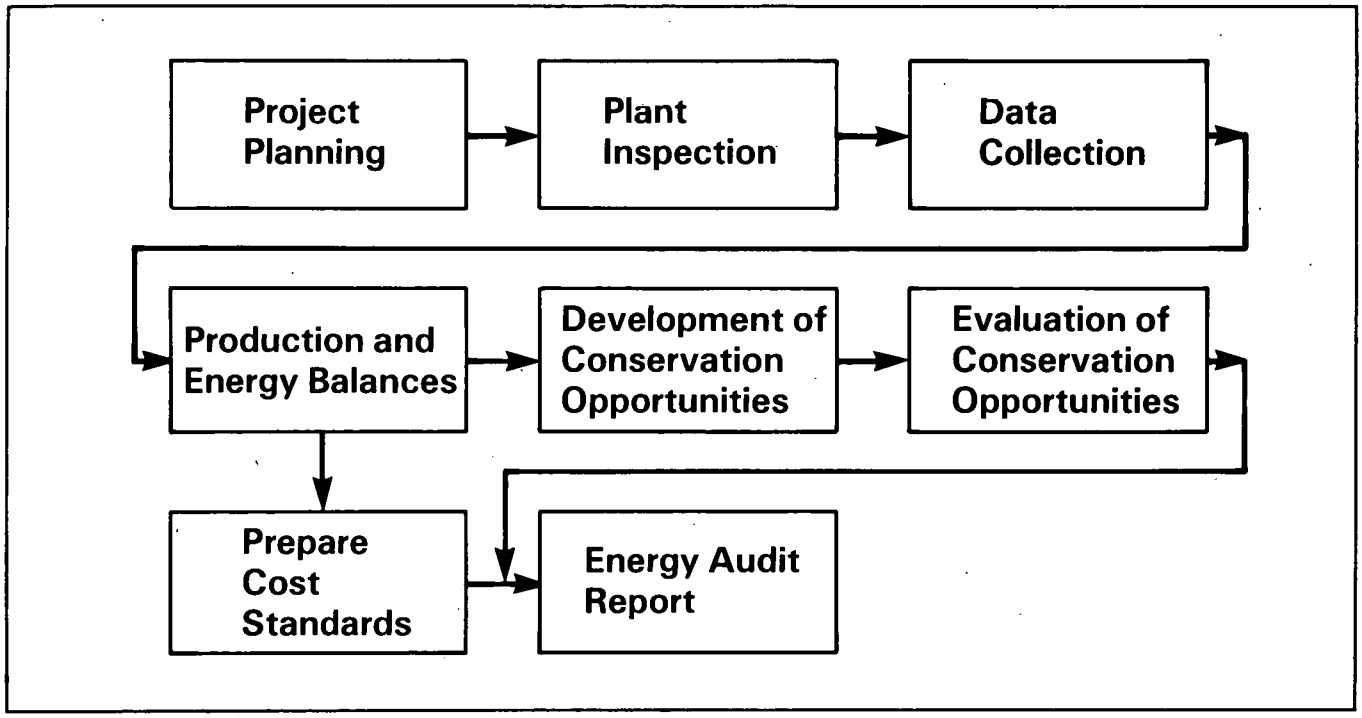


Figure 4. Energy audit procedure.

of how energy is used in a plant. It requires time, testing, and a survey of the plant's energy systems. Figure 4 describes an Energy Audit procedure for use by the plant energy coordinator or the plant's consultant. The Department of Energy and State Energy Offices have all promulgated detailed workbooks on how to perform an Energy Audit so the detailed procedures will not be described in this paper. Results of the Energy Audit are summarized in a report and include operational changes and capital projects which, if implemented, will reduce energy cost and consumption.

A team of engineers, mechanical, electrical, and chemical, is usually required to complete a plant Energy Audit. The team must survey operational procedures during production and analyze the boilerhouse, electrical distribution system, and lighting system. If large HVAC and compressed air systems are involved, they should be included in the audit. Using test instrumentation, the survey team will collect departmental energy information that can be utilized to set more specific energy standards. Process and equipment specifications will be compared to actual test results to determine if the equipment or processes are operating at rated efficiency. Modifications will be recommended to bring processes or equipment up to performance specifications or redesigned to exceed original specifications.

An Energy Audit consists of all the work performed in a Rational Analysis plus:

- Data collection and testing.
- Evaluation of in-plant energy utilization on a departmental basis.
- Development of energy conservation opportunity projects.
- Preparation of a report evaluating energy projects based on cost savings and return on investment.

When the testing, definition and evaluation of projects are complete, calculations are made for capital costs required to implement each project. These results are summarized in a report and submitted to management for implementation based on return on investment or life cycle costing. A further result from the Energy Audit is a more accurate description of where energy is used in the plant; the allocation of energy is more accurate with an Energy Audit than with a Rational Analysis. From the Energy Audit, energy standards can be set for each building, department or process line. The standards can be used as goals to be met or exceeded, and thereby encourage departmental energy use effectiveness.

The cost of an Energy Audit is greater than a Rational Analysis since it requires team testing, more detailed calculations and a report. Figure 5 describes the reduction in energy consumption after a Rational Analysis or an Energy Audit is completed. Savings from the Energy Audit are greater than from the Rational Analysis.

The Energy Audit results in a decrease of energy consumption initially. However, since there isn't an Energy Management

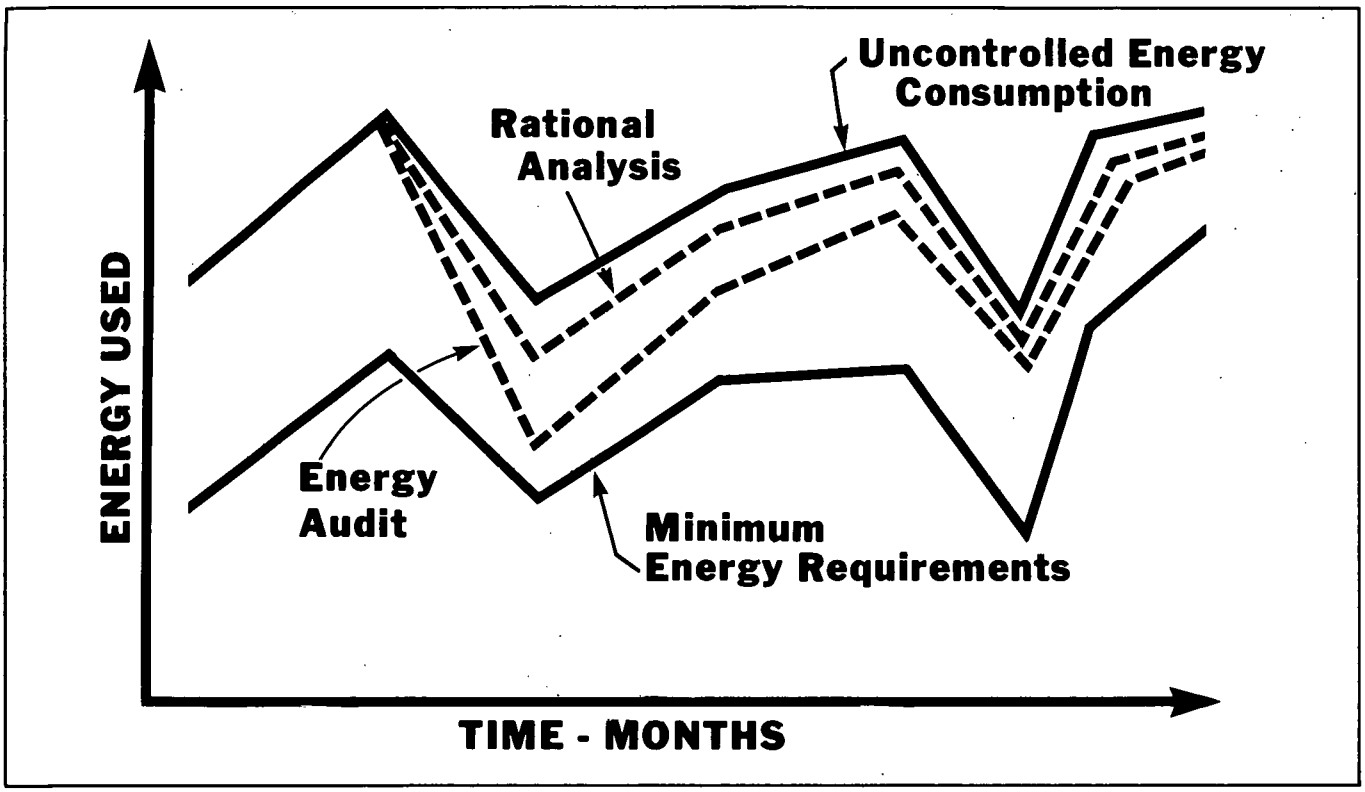


Figure 5. Plant energy use.

System, the plant can slide back into old energy inefficient ways and results achieved in the audit are lost over a period of time. This is also indicated in Figure 5 by showing a return of the Energy Audit savings close to uncontrolled energy consumption after time had elapsed. The cost of an Energy Audit can vary from $10,000 to $250,000 depending on the size of the plant and the complexity of the processes within it. It can be repeated periodically or combined with a Rational Analysis to maintain some control of energy use. It does not maintain energy costs at their lowest possible level over a long time span.

ENERGY MANAGEMENT THROUGH METERING

The most accurate method of allocating energy in a plant is to measure it. An Energy Management System based on utility metering will provide accurate allocations of energy and the information required by top departmental managers to efficiently use energy in their production processes. Utilities that should be considered for metering are: electricity, fuel (natural gas), steam, compressed air and water. Metering should be done on a departmental basis, conforming to the cost accounting system that is used to budget raw materials and labor to individual production processes in a plant.

The information obtained from the meters can be transmitted through microprocessors to the same computer used for cost accounting of labor and raw materials. Then energy is managed as well as raw materials and labor because energy consumption is compared to budgeted standards for each month, and a variance calculated to determine if energy costs are in line with the standards for each department. Table I describes the electricity and steam used in the Frame Production Department for the month of February. The electricity and steam consumed is compared to standards and variances calculated. In conjunction with the cost of steam and electricity, the cost of energy to produce frames is compared to a standard and the actual bottom-line energy cost for the month of February is determined. This is the factual data required to manage the energy use in a department.

A further advantage of the Energy Management System by metering is it will provide the information necessary to keep energy cost closest to minimum energy requirements on a continuing basis. Figure 6 describes the result of installation of an Energy Management System after completion of an Energy Audit. The energy saved after implementation of projects identified by the Energy Audit will continue to be saved on an ongoing basis because the Energy Management System provides feedback information and records indicating whether changes made have improved or reduced energy use.

Most plants have found that to save energy, you have to first know how you are using it. You cannot save it until you can measure it; and the means for measuring electricity, steam, compressed air, and other energy streams is a metering system. The advantages of installing an energy metering system are:

- Promotes accountability for energy use on a departmental basis.

- Provides records indicating whether changes made to processes have improved or reduced energy use.

- Provides feedback information to department managers on the use and cost of energy. Provides a measurement system which forms the basis for management of energy on a continuous scale similar to the management systems for labor and raw materials.

The results of the metering system will be an increase in profitability by minimizing energy cost. With an Energy Management System installed in your plant, energy cost will no longer be ignored; they will no longer be given the lowest priority because energy costs will be identified and be held accountable to production on a departmental basis.

METERING SYSTEMS

A variety of meters are available for measuring energy streams. A typical installation of an electric turbine meter for measurement of steam flow is indicated on Figure 7. Table II is a compendium of meters available for various fluid applications. Accuracy and turndown of the meters are important parameters that must be evaluated when installing a meter system.

TABLE I – ENERGY MANAGEMENT DATA

ENERGY PRICES – ELECTRICITY AND STEAM – FEBRUARY 1980

Energy Center: Frame Production Area

Energy	Energy Content
Electricity	0.003413 X 10^6 Btu/kWh
Steam	0.868 X 10^6 Btu/10^3 lb

Energy Prices

	Current Month		Std. (budget) Prices		Price Variance	
	$/Unit vol	$/$10^6$ Btu	$/Unit vol	$/$10^6$ Btu	$/Unit vol	$/$10^6$ Btu
Electricity	$0.03/kWh	$8.79	$0.028/kWh	$8.20	$0.002/kWh	+$0.59
Steam 125 psig sat	2.52/10^3 lb	2.90	2.60/10^3 lb	3.00	0.08/10^3 lb	–0.10

ENERGY QUANTITIES

Energy Center Frame Prod Month/Yr February 1980 Production 120,000 (Current) 250,000 (Ytd)

	Total Consumption						Energy per Unit of Production					
	Current Month			Year-to-Date			Current Month			Year-to-Date		
	Actual	Standard	Variance	Actual	Standard	Variance	Actual	Standard	Variance	Actual	Standard	Variance
Electricity (10^3 kWh)	250	300	-50	550	600	-50	2.08	2.5	-0.42	2.2	2.4	-0.2
Steam (10^3 lbs)	6,000	5,800	+200	13,500	13,000	+500	50	48.3	+1.7	54	52	+2.0

ENERGY COSTS

Energy Center Frame Prod Month/Yr February 1980 Production 120,000 (Current) 250,000 (Ytd)

	Total Costs						Cost per Thousand Frames					
	Current Month			Year-to-Date			Current Month			Year-to-Date		
	$	Standard	Variance	$	Standard	Variance	$	Standard	Variance	$	Standard	Variance
Electricity	7,500	9,000	-1500	16,500	18,000	-1500	62.5	75	-12.5	66	72	-6
Steam	15,120	14,620	+500	34,020	32,760	+1260	126	122	+4	136	131	+5
Total ($)	$22,620	$23,620	-1000	50,520	50,760	-240	188.5	197	-8.5	202	203	-1

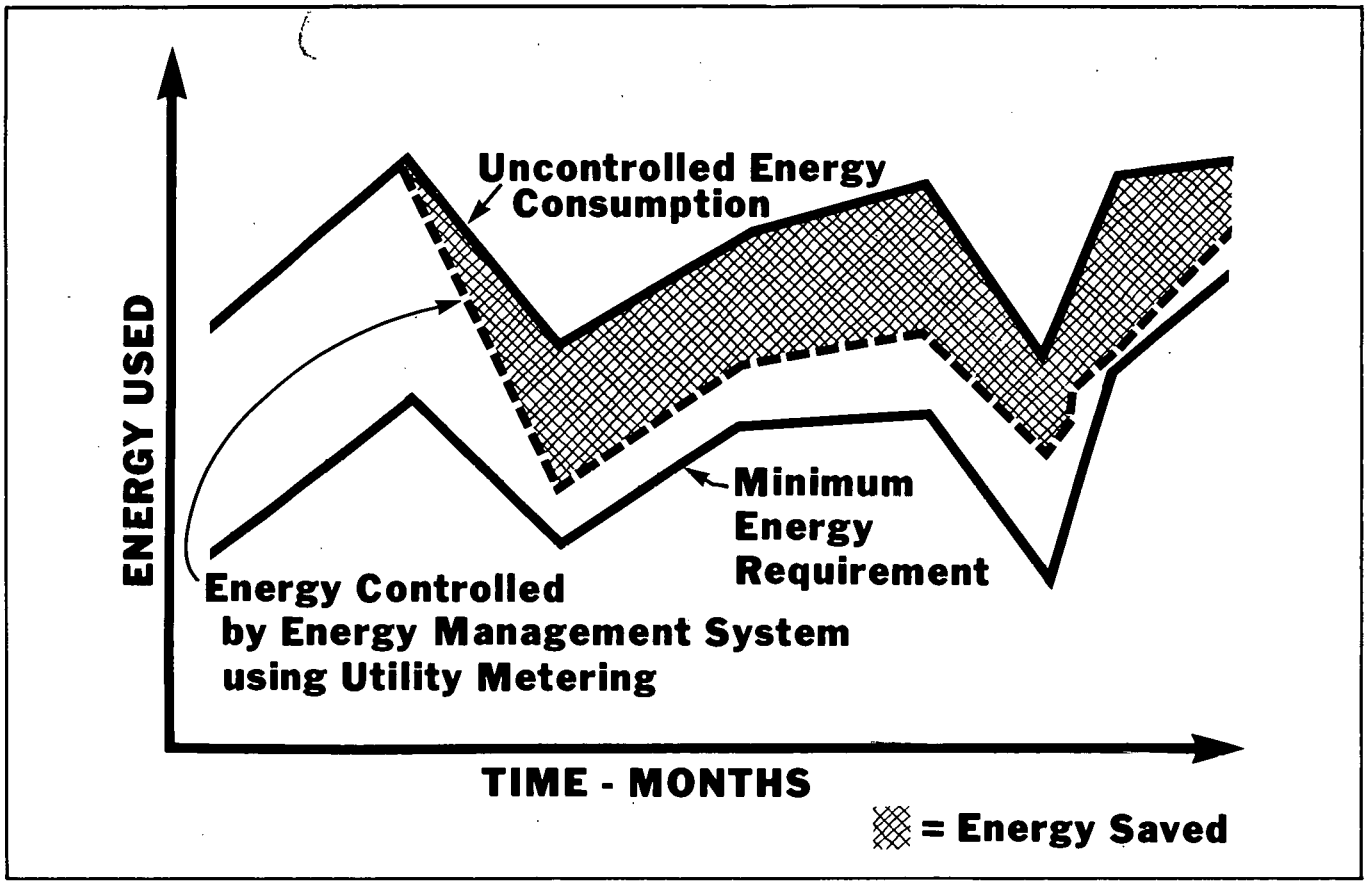
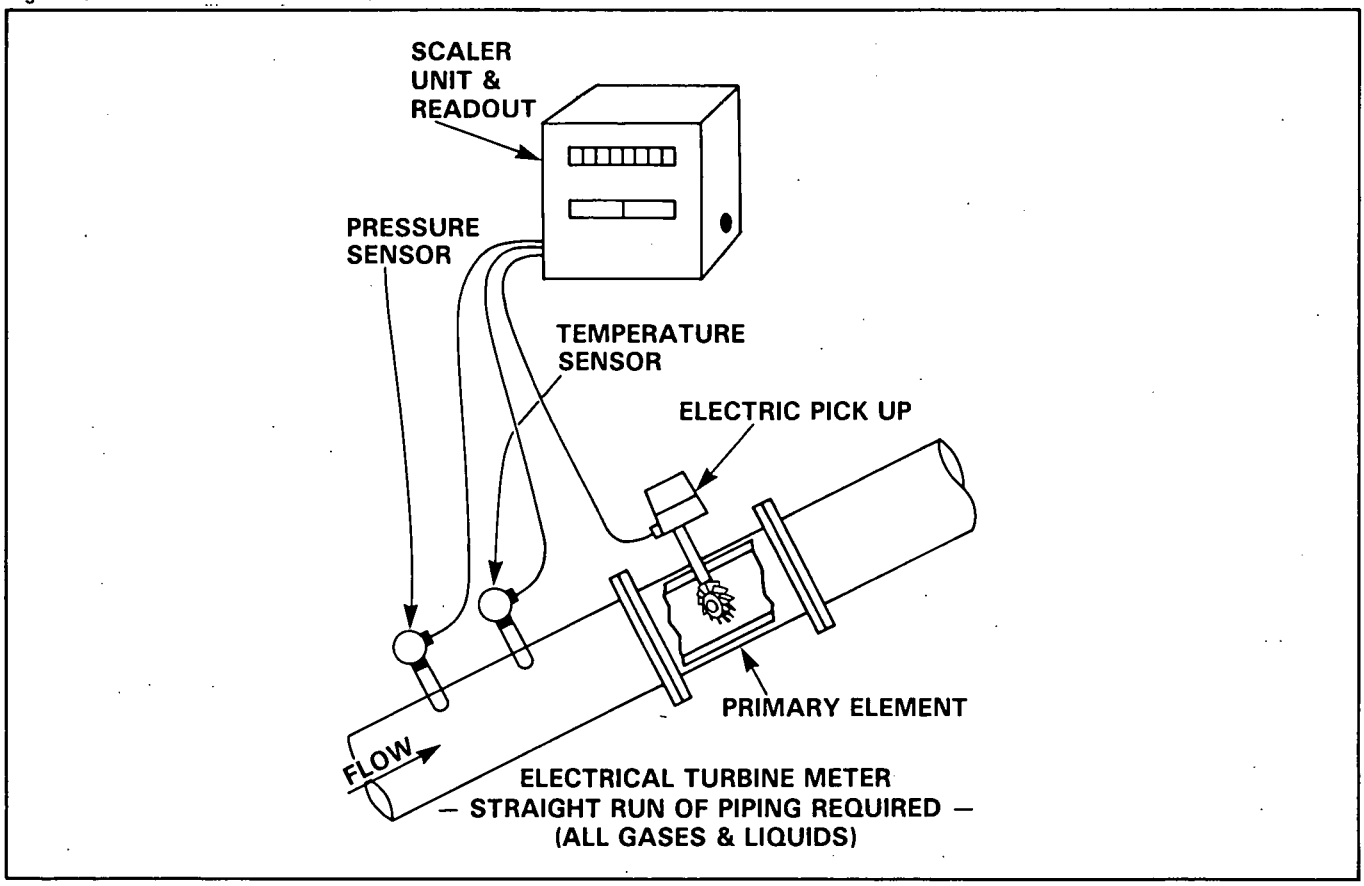


Figure 6. Plant energy use with energy management.

Figure 7. Turbine meter installation.



Orifice meters for measuring flows of steam, compressed air and natural gas do not have the accuracy and turndown required, and many plants are using turbine meters and vortex shedding meters to obtain required accuracy.

The installed cost of a meter is from $8,000 to $18,000 per meter depending upon the accuracy and turndown required, and whether the output signal is to be handled by a microprocessor or computer. Also included in the cost are recorders and integrators for local readout of energy use. It is recommended that a preliminary engineering study be performed to determine plant requirements before plunging into a detailed design of an Energy Management System. Net program costs will be reduced.

Several companies are proceeding with Energy Management Systems using utility metering. Justification of the Energy Management System is based on the rapid escalation of energy costs and the necessity to control these costs on a continuing basis. Installation of an energy metering system will yield an approximate three year payback based on energy cost reductions uncovered by the utility metering system and the fact that without the metering system energy will be wasted.

TABLE II – METER CHARACTERISTICS

TYPES OF FLOW METERS	FLUID APPLICATIONS					ACCURACY & TURN DOWN		INSTALLATION REQUIREMENTS					PRIMARY SIGNAL		OUTPUT SIGNAL			
	GAS	COMP. AIR	STEAM	WATER	OILS	% FULL SCALE	TURN DOWN	ST. RUN	FLOW CONDITIONERS	BYPASSES	FILTERS/ STRAINERS	WET/HOT TAPS	ANALOG	DIGITAL	ELECT.	MECH	PNEUMATIC	INDICATING
DIFFERENTIAL PRESSURE																		
ORIFICES	✓	✓	✓	✓	✓	2-3	3:1	15U-5D	R*	NR	NR	NA	√		✓		✓	✓
NOZZLES & VENTURIS	✓	✓	✓	✓	✓	2-3	3:1	15U-5D	R*	NR	NR	NA	√		✓		✓	✓
VENTURI TUBE	✓	✓	✓	✓	✓	2-3	3:1	15U-5D	R*	NR	NR	NA	√		✓		✓	✓
PITOT	✓	✓	✓	✓	✓	2-3	3:1	15U-5D	R*	NR	NR	NA	√		✓		✓	✓
TURBINES	✓	✓				1	100:1	NR	NR	R	R	NA		✓		✓		✓
TURBINES	✓	✓	✓	✓	✓	1	15:1	15U-5D	R*	R	R	A		✓	✓		✓	✓
VARIABLE ORIFICE	✓	✓	✓	✓	✓	1	60:1	NR	NR	R	R	NA		✓	✓	✓	✓	✓
VORTEX	✓	✓	✓	✓	✓	1/2	25:1 100:1	15U-5D	R*	R	R	A		✓	✓			✓
SHUNT	✓	✓	✓	✓	✓	2	10:1	15U-5D	R*	R	R	NA		✓		✓		✓
VARIABLE AREA	✓	✓	✓	✓	✓	3-10	10:1	15U-5D	R*	R	R	NA		✓	✓	✓	✓	✓
POSITIVE DISPLACEMENT				✓	✓	1	15:1	NR	NR	R	R	NA		✓	✓	✓	✓	✓
POSITIVE DISPLACEMENT	✓	✓				1	100:1	NR	NR	R	R	NA		✓	✓	✓	✓	✓
MAGNETIC	FLUID MUST BE CONDUCTIVE					1	30:1	NR	NR	R	NR	NA		✓	✓	✓	✓	✓

15U – 15 DIAMETERS UPSTREAM
5D – 5 DIAMETERS DOWNSTREAM
R – REQUIRED
R* – REQUIRED DEPENDING ON PIPE CONFIGURATIONS
NR – NOT REQUIRED
NA – NOT AVAILABLE
A – AVAILABLE

A COMPREHENSIVE ENERGY AUDIT OF A LARGE PRODUCTION UNIT IN SIX WEEKS

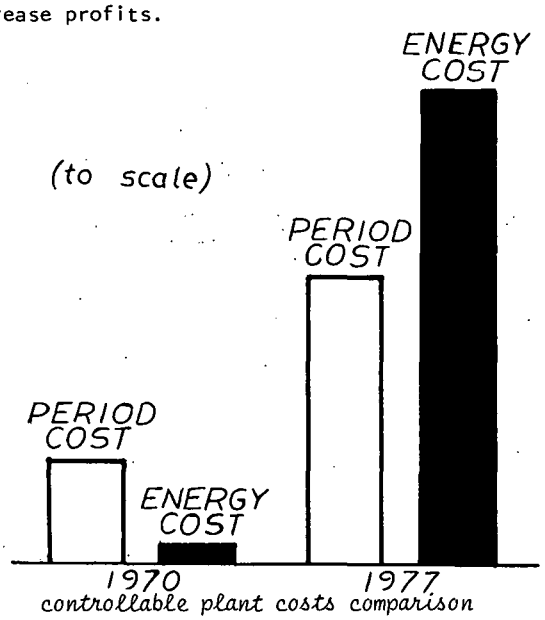
Robert D. Korich
Union Carbide Corporation
Seadrift, Texas Plant

ABSTRACT

Past energy audits of petrochemical plant production units at Union Carbide have demonstrated that the key to an effective, comprehensive audit of a large production unit is to minimize the time period requirement for the team activity. This paper describes a comprehensive energy audit performed in six weeks on a large and relatively new production unit. This audit resulted in identifying and evaluating 62 opportunities reducing annual energy usage by $2,000,000.

ENERGY PROBLEM - Primarily as a result of a national energy supply/demand deficit that has been steadily widening since the late 60's, energy costs at Union Carbide's Seadrift, Texas plant have been escalating at an alarming rate. Over the past 8 years, incremental energy costs have increased an average of 39% each year causing present costs to be almost 14 times higher than 1972.

This highly unstable situation has created a real need to adjust techniques of profit maximization management which have historically centered on period cost reduction. As demonstrated in the graph below, methods such as overtime control, reduced staffing, and improved material purchasing procedures are loosing their leverage relative to energy conservation as an effective means to increase profits.



controllable plant costs comparison

The bar graph shows period costs and energy costs for 1970 and 1977, during a time when the plant doubled in size. Period costs in this interval tripled. Taking into account the expansion of the plant, period costs rose 50% over these 7 years due to inflation. This increase corresponds to a 6% rise each year. During this same period, total energy costs have increased almost 25-fold going from 20% of period costs to more than 150% of period costs. The lesson is clear -- in spite of the inflationary spiral of period costs and its devastating impact on profitability, energy costs have risen at a rate 7 times faster than period costs. Energy conservation activity is the real area of opportunity for improving profits. Formal and comprehensive energy audits of production units is one of the prime tools available to industrial plants in this area.

TEAM CONCEPT OF AN ENERGY AUDIT

Advantages of an Audit Team

An energy audit of a large production unit in an integrated petrochemical plant can be a highly complex endeavor with a labyrinth path of obstacles, concerns, and questions. Consideration is required about available technology, operations impact, the present and future circumstances of the plant and the unit economic factors. The study also requires a blend of innovativeness with past learning experience as well as adequate resource availability to perform the multitude of tasks required for a thorough and useful analysis.

The use of a team to perform the energy audit represents the best vehicle to solve these problems. A properly staffed team can provide rewarding input from a broad functional representation as well as

needed review coverage to insure a viable energy conservation opportunity. A wide work background mix provided by a team can extend the idea generation into areas that are fresh but still proven. Interaction among the team can also take old, unworkable concepts and schemes and cultivate a novel variation to be implemented. The additional staffing availability represented by the team also is a significant, practical advantage in accomplishing the immense workload of a detailed energy study.

Therefore, for a variety of reasons, a vital prerequisite for a comprehensive energy audit is the use of an audit team concept.

Problems of an Audit Team

In all past energy audits in the company there had been significant problems in getting the team concept to work smoothly as an effective tool. The dominant plight was turnover of team personnel during the life of the team activity, which had detracted from both the quality and schedule of the audit. During the 6 to 18-month span of past audit team activities, virtually every team member was either rotated out of the team or came into the team well after it had been organized and functioning. Continuity of team membership is imperative in avoiding the disruptive effect caused by fragmenting work of the individuals, bringing new members up to speed, adapting the team interaction to a new mix of experience and personalities, and drifting away from original team objectives and convictions. However, given sufficient time lapse, membership turnover is unavoidable due to functional reorganization and career development moves.

Past audit teams had also been plagued with shortcomings on receiving and holding manpower commitments. In too many cases the team members' participation was significantly diluted for extended periods by competing demands. It should be recognized that failure to receive adequate priority is inevitable when an activity competes with production support for the lengthy use of limited resources. This problem not only detracts from the effectiveness of the team by diminishing the manpower to accomplish the work, but also undermines a powerful asset -- team interaction. The team can not consistently mesh its varied input as a cohesive unit when its members are being intermittently pulled away on a staggered basis for other work. As inferred before, this priority dilemma is mainly a result of the inability to furnish limited resources for a prolonged time period when these resources can be contributing to production needs.

The problems of staffing turnover and resource priority commitment are closely related in that both are greatly aggravated by longer periods of team activity. Therefore, a primary requirement for an effective audit is to keep its activity period concise. An important method to minimize the time involvement is to limit the work required of the team to that which truly requires team effort. A great deal of preparation must be carried out before the team performs that work for which it is most qualified: to conceive, develop, and evaluate ways of monitoring and reducing energy usage.

Critical Key to an Energy Audit

From the previous discussion of the advantages and problems with the team concept of an energy audit, the conclusion is that the critical key to an effective and a comprehensive energy audit is a team with an activity period of short duration. This deduction was the central theme and the cardinal guideline of this subject audit. By keeping the team activity to 6 weeks, this audit was highly successful in eliminating staffing turnover and in obtaining a high resource priority commitment. In comparison to past audits, this one progressed smoothly on schedule, accomplished a more thorough and detailed energy analysis of the unit, and identified more energy conservation opportunities. In short, it was a less painful and more successful energy audit.

It is worth noting that a more abbreviated way of stating the critical key "significant preparation." This obviously is not a revolutionary or sophisticated concept. What was unique in this audit was the recognition of the full impact of this concept and the extent and the determination to which it was performed.

THE SUBJECT AUDIT

Unit Background

The specific unit audited was a much newer unit than had been typically audited by the company in the past. The majority of the detailed final design was performed after the oil embargo of 1974, and therefore, energy conservation was a significant

criteria in the design of the unit. The identification of large amounts of savings potential was not the major motivator in this audit. The prime concentration was the development of a good audit procedure. It was acknowledged that this audit would be hard pressed to find the 10-15% reduction potential that had been historically the result of past audits in older units, where opportunities were more numerous.

Audit Results

The six-week audit was highly successful in identifying and evaluating energy conservation opportunities. There were 62 ideas evaluated during the audit. One idea was fully implemented during the audit and created an immediate annual savings of almost $53,000. Including this idea, there were 10 good ideas that were feasible and economically justifiable worth annual savings of $680,000 for a cost of $50,000. Another 17 ideas worth savings of $2,400,000/year were determined to be practical projects whose costs were unknown but probably justified. These two groups comprised the 27 audit-recommended projects worth over $3 million per year. Assuming about half of the maybe projects would become good projects, the estimated final result of this energy audit is a $2,000,000 reduction in energy usage.

Of the remaining projects identified in the audit, $2 million in annual savings were considered feasible after marginal advancement in technology and the other ideas were determined to be totally unfeasible and/or grossly uneconomical.

The net cost to the production unit was $25,000. As can be seen, the immediate savings gained during the audit easily justified the cost of the audit.

A very gratifying feature of the projects identified to implement was that the vast majority required very little follow-up resources to complete. Only one of the 10 good projects and 1/3 of the recommended projects required plant engineering design or capital-type money to implement. The large portion of the savings could be realized with minor, unsophisticated engineering and with expense money. This is a reflection that this new unit was energy-efficient in the overall design with few design revision opportunities. Most of the savings were a result of specific, detailed modifications to the operation of the unit for more energy efficiency.

STAFFING OF THE TEAM

A critical element to any audit is the staffing of the team. The staffing of this audit team was critiqued to be a strong point that made a significant contribution to the success of the audit.

The working team membership consisted of 4 full-time, on-site people during the six weeks. This number of people was an optimum size. It was a small enough group for a smooth, working relationship to exist and in turn to foster work efficiency. At the same time it was large enough to provide the necessary variety of input to insure work quality. There were also 4 part-time members who either provided specific input during team meetings or were identified as a resource for particular areas of technology. This approach was very effective in obtaining specific and needed information from a variety of people without burdening the working team with too many people.

The total manpower spent on this energy audit was 9½ man-months. About 6 of these were spent during the six-week team activity. The rest was utilized in the planning and preparation stage which consumed nearly half of a person's time for about 8 months before the team activity.

The full-time membership of the audit team included the following:

1. Unit Representative/Team Leader -- this person was an experienced production engineer from the unit being audited. About 1/3 of the time he spent on the energy audit was in the role of Team Leader. In his dual role, his responsible areas of contribution included the following:
   a. provide unit input to the team
   b. provide leadership, organization, and coordination of the team's activities and the members' individual assignments
   c. publish meeting minutes, reports, and other documentation by the team.
   d. monitor audit costs
2. Process Engineering Representative -- this person was an experienced process engineer from the company's central technical engineering center. His responsible areas of contribution included the following:
   a. provide process engineering input to the team
   b. act as a liason with R&D and Engineering Center personnel in the area of the

process technology applicable to the unit being audited.

3. Plant Energy Systems Representative -- this person was an experienced production engineer in the plant Energy Systems Department who was familiar with the plant utilities distribution systems. His responsible areas of contribution included the following:

a. provide energy systems input to the team
b. evaluate potential utility savings in the light of the plant's utility distribution balance and situation

4. Electrical Engineering Representative -- this person was a member of the plant Maintenance Engineering/Reliability group. Included in his responsible areas of contribution were the following:

a. provide input for the electrical balance portion of the audit
b. provide expertise in the area of electrical distribution.

An electrical engineering expert was chosen to fill this slot rather than a mechanical equipment expert because of a significant share of unit's energy usage was represented by electricity, because of the unit representative's strong mechanical equipment background/expertise, and because of the team's general weakness in the area of electrical engineering.

The part-time membership of the audit team included the following:

1. Team Advisor -- the person was the plant Energy Conservation Coordinator with experience from past energy audits. He attended all team meetings and was responsible for contribution in the following areas:

a. provide advice and direction on audit team activities.
b. act as a liason with other company energy conservation functions

2. Impartial Production Representative -- this person was an experienced production engineer in another production unit who had no previous experience in the unit being audited. This individual was from the next unit scheduled for an energy audit to provide direct continuity in audit procedures and expertise. He also attended all team meetings with the following areas of contribution:

a. provide additional practical production and operating input to the team.
b. provide a fresh, unbiased, and innovative process engineering input to the team -- to ask the "stupid" questions that can lead to overlooked opportunities.

3. Energy Systems Engineering Representative -- this person was from the company's central technical engineering center as part of the energy systems engineering group. He was an identified resource for the team to use on an as-need basis to provide support to questions in the area of energy recovery technology.

4. Process Control/Instrumentation Representative-- this person was an Instrument Engineer in the Plant Engineering Department. He also was an identified resource for the team to use on an as-need basis to provide support to questions in the areas of instrumentation and process control.

AUDIT STAGES/PROCEDURES

Planning/Preparation

This stage of this energy audit was probably the biggest change from past audits in its magnitude and was also the single biggest reason for the higher level of success. Plenty of time was allowed for thought to go into this activity. The conception of this type of an audit in this production unit was generated a year before the audit started. A kickoff meeting was held seven months before the audit with unit, plant, and business management to receive their understanding and agreement of the basic precepts of the audit proposal.

Following this initial planning meeting, the major effort was staffing of the audit team. A direct face-to-face request of various supervisors for manpower occurred six months before the audit and was highly successful. This success was mainly due to the informal atmosphere that allowed the Team Leader to go directly to various Department Heads and to the Plant Manager's Department. Commitment to meet the staffing needs was obtained from all appropriate supervisors five months before the audit, and all members were identified by name three months before the audit.

A second planning meeting was held five months before the audit at which time the specific objectives were set. In general, these objectives were the following:

1. to identify energy conservation opportunities and to have evaluated each for technical feasibility and economic justification
2. to have refined an energy balance sheet that is broken down by utility type and process subsystems for use as an effective management tool.
3. to have defined potential energy usage goals for the unit into the future with projects/programs to achieve these.
4. to have assembled a package of specific recommendations and guidelines to other similar existing production units in the areas of energy program coordination/management and process/equipment improvement areas.
5. to have developed recommendations on techniques/procedures for performing energy audits in other units in the plant in the future.

Besides the first two planning meetings, there was a third planning meeting three months before the audit to discuss instrumentation requirements of the audit and to pass out resource material to the team members. Finally, there was a fourth planning meeting one month before the audit to discuss the detailed plan of attack and to tie up any loose ends. Adequate meetings in the planning stage were considered important in this audit as in any activity involving coordination of people and functions into a complex effort. In compliance with effective meeting techniques, in all cases, an agenda of the meeting was sent out at least a week ahead of time and minutes were issued within a week after the meeting.

The resource material that was given to each team member consisted of two manuals compiled by the unit representative. The first one was a process description manual which included the following up-to-date items:

a. flow diagrams
b. layout drawings
c. energy-related equipment specifications and data
d. energy-related control systems sketches
e. list of all motors in the unit with data
f. detailed description of baseline operating conditions to be used for the energy audit

The second manual was a unit energy manual which included the following:

a. past detailed energy usage data
b. documentation of six past energy usage studies each with very limited scopes. (The past 6 mini-audits on very small segments of the unit were most helpful in expediting this energy audit)
c. documentation of all past energy conservation projects and idea lists.

The first week of the team activity was spent in a unit orientation, reviewing all of the resource material along with walking tours of the unit.

Preliminary Balance

The major product of the preparation phase was a preliminary unit energy balance done by the unit representative. If there was any single specific activity that was the chief contributor to success, the preliminary balance was it. Its main contribution was an early indication of missing data needed and potential areas of concern for the audit team to quickly zero in on during the initial activities. An important outgrowth of the deficiency analysis aspect of the balance was an identification of critical instrumentation needs before the audit team activity and with enough time to take corrective action. Also, the preliminary balance was a work short-cut in that some of the preliminary balance work was adequate enough to be used for the final balance. The preliminary balance quickly defined a starting point for the audit team activity.

The preliminary balance was an attempt to define an actual energy usage split in the unit. It used historical data collection and measurements of existing meters as well as calculations using a combination of measurements and best-guess estimated data. The preliminary balance was better than 85% effective in "closing the loop" by having the balance segments account for the total usage.

The preliminary unit energy balance was immensely successful at providing an early warning of specific obstacles that lie ahead for the audit team. This forewarning allowed premature corrective action that smoothed the way an effective team activity of short duration.

Unit Energy Balance

The first part of the team activity following the week of orientation was to perform an energy balance of the unit broken down by utility and by area of the unit. The various utilities were assigned to the individuals of the working team. An assignment by utility rather than by unit area was preferred

to maintain continuity in techniques that would "close the loop" on each utility. This phase of the audit was finished in two weeks.

The energy usage in the audit balance was made to represent what "ought to be used" with good but practical performance. It was made to be used as a measure of good performance. For example, on a large compressor where the optimum pumping efficiency would be 100% and the actual pumping efficiency was measured at 96.3%, the audit balance used 95%. This latter value is a generally accepted value of good pumping efficiency. Therefore, the audit balance represented efficient operation that could be bettered on occasion. Variance between actual performance and the audit balance represented energy conservation opportunities by eliminating operating inefficiency. Variance between optimum usage and the audit balance represented energy conservation opportunities by technical modifications to reduce inefficiencies inherent to the system as it existed at the time of the audit.

The data required for the audit balance started with the preliminary balance which required some minor revision to convert it from actual usage to the new standard. Data measurement for the audit balance is obviously a critical area. Only about ¼ of the required energy balance data was directly measured by existing installation. The major portion of the data was provided by calculations of energy balances of isolated subsystems and using measured data from the extensive instrumentation in the actual process. Some portable instrumentation for steam flows and remote temperature measurement were also used. In some cases, design report data (i.e., pump curves) were used but only after a sample data point and assumptions were confirmed. Finally, where all other alternatives were unavailable, innovative but crude techniques were used such as trapping condensate in a graduated barrel for a time period or using a stethescope to estimate the percentage of time a trap is full open.

An extra but important effort in the balance phase was to define "conversion factors" on the major operating variables to a new energy usage. This allowed the balance as a performance standard to change and maintain its validity inspite of changes from baseline conditions in production rate, product specifications, operating pressure, and/or operating time. Therefore the audit's unit energy balance performed at one point of time for one set of conditions became highly useful on many sets of conditions far into the future.

Opportunities and Proposals

As the team started its fourth week, it reached the phase to begin identifying savings potential. A total team meeting was held to review the audit balance and the preliminary balance and the historical actual usages. A list of observations by the team about differences in these numbers laid the foundation for some potential opportunities. With this list and balance data in hand there were extensive energy conservation brainstorming sessions with unit personnel. Following these sessions there was always an audit team meeting to reiterate each idea and discuss methods to analyze it. Coming into these brainstorming sessions well prepared helped to insure success at drawing out a multitude of ideas to look at.

The 62 ideas resulting from the brainstorming sessions were assigned to individual team members. After a week of work on an individual basis to define a preliminary proposal on each opportunity, there was a day-long review session of the entire audit team in which each member of the team presented his proposals for comments. These were noted and the members spent the remainder of the 5th week incorporating this input into a final proposal.

This approach to handling the energy conservation opportunities was felt to be an outstanding method in that the individual work avoided the delays inherent in a committee performing the work, and at the same time the review allowed the final proposals to be a team product with consistency and a variety of functional input.

Another major contributor to success in evaluating all the ideas, was the team not falling into the trap of going too far on these ideas. It was noted early and continuously reemphasized that the scope of the team was strictly and purposefully limited to an audit, per se (Webster definition of an audit -- examination). The team did consider rough economics where possible and implementation requirements or problems in their analysis of energy conservation opportunities, but time was not spent on detailed design work or implementation. Ideas were left in the form of proposals for the production unit to follow up on.

Critique & Final Report

The sixth and final week started with a critique of the audit which was highly positive. The only significant recommendations were for bolstering the plant coordinating function to accelerate this type of audit in other units in the plant. The remainder of the final week was spent collecting notes and other documentation for the final report.

An immense effort was spent on the final report to insure it reflected and fully captured the huge amount of useful work done during the audit. The Team Leader spent half his time for two months putting it together. During this time period several advance excerpts were issued to avoid delay in consideration and to highlight their importance.

The product of this effort was a 400-page report that is still today (a year later) frequently referred to as the ultimate energy reference in the unit. To facilitate its use, this huge report was broken down into the following sections:

1. a 2-page summary
2. a 138-page final report with a one-page summary on each of the 62 opportunity proposals
3. a 250-page appendix with a copy of all the member's notes and calculations

MANAGEMENT TOOL

Monthly Usage Variance

One of the most widely-used tools for energy management is a monthly comparison of actual usage as compared to a budgeted value. However, there are three serious flaws in using this approach. First, the budget is usually based on past performance as a standard. There is no way of knowing if this represents good performance or prolonged bad performance. This energy balance is known to be based on good (but practical) performance.

A second deficiency of the more conventional system is that the budget is based on a fairly fixed set of operating conditions that may not still be valid. The ability of this audit balance to change with varying operating conditions eliminates this problem.

A third deficiency usually encountered is an inability to quantify the effects of variance causes to insure the entire variance is fully accounted for. With the large amount of calculations performed in this audit and documented in the final report, this is now possible in most cases.

With this audit, the unit developed a highly accurate work sheet that is used every month to define a performance usage standard and then systematically and in detail define causes and quantities of variances. Over a period of a year it has specifically identified over 85% of the variance causes.

This ability is a huge stride forward in effective energy management.

Day-to-Day Operations

After performing this in-depth audit, and especially the energy balance, the most critical operating parameters for energy efficiency can be easily identified. In this unit, the 8 most important ones were put on one log sheet for the operators to periodically check. Also, on this sheet is a recommended limit for each as well as action for the operator to take if a limit is exceeded. Therefore, the audit has put the energy manager in a position to effectively develop one sheet of paper that will guide the operator to quickly monitor the unit on a daily (or more) basis for energy efficiency as well as greatly magnify the operators' energy awareness level.

Also as a result of the calculations performed, a computer can be easily programmed to perform these same calculations. Therefore, by feeding it a continuous stream of actual measured process data, the computer can be continually making updated calculations that can provide a multitude of instantaneous data to the energy manager about the energy efficiency of the unit.

Planning

The audit balance and its ability to compensate for varying baseline operating conditions obviously makes it a powerful tool for quickly and effectively planning and budgeting on a year-to-year basis.

What may well be the most important potential result of this energy audit is a long-range, 11-year program at reducing energy to an "ultimate" level. The opportunities listed as awaiting minor and feasible technology advances can be sequenced into the audit balance to define a reasonable potential, a timetable, critical paths, and requirements for an R&D program to best support energy conservation. Certainly, this ability to perform effective long-range planning is a desperately needed commodity on a long-range problem like energy.

SUMMARY

A team is required to perform a comprehensive, in-depth energy audit of a large production unit. A criteria in making this audit an effective one is to keep the team activity to a short duration.

The specific keys to this energy audit included the following:

a. 6-week team activity through significant preparation including a preliminary energy balance and previous energy studies
b. proper staffing of an optimum number of multifunctional members on the audit team
c. the optimum combination of individual and team work activity
d. the early and specific definition of the audit objectives, the team's scope of activity, and the member's individual roles.

A common element that runs through the breadth of this audit is that an energy audit is not a technical problem, but rather a management one.

ENERGY AUDITS ON PRINCE EDWARD ISLAND

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and

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ABSTRACT

High energy costs and uncertain supplies force industrial operators to seek out energy waste to keep costs down. The Enersave for Industry and Commerce program assists Prince Edward Island industries through an energy audit and grant program. A typical audit shows how one processor doubled his output with no increase in energy use.

It has been estimated in Canada that 48% of all energy used is wasted. While we can all envision an illuminated city skyline to be symbolic of energy waste, the problem is by no means confined to large urban areas.

The sharp escalation in cost and high degree of uncertainty of supply of energy, particularly petroleum products, are factors which affect all parts of our society today from the largest of cities to the smallest of country hamlets.

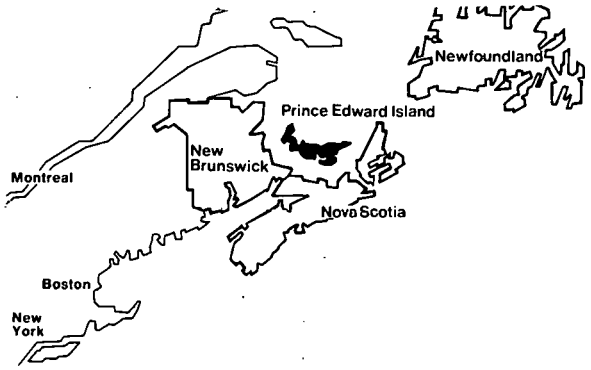


Fig. 1 Location Map of P.E.I.

In terms of size, no one could call Prince Edward Island large. Located on Canada's East Coast this tiny province of Canada boasts a population of only 120,000. Yet in terms of degree the energy problem in P.E.I. is one of the most acute in Canada.

Totally dependent upon imported petroleum products, with little in the way of indigenous energy supplies, energy costs in P.E.I. are the highest in Canada. With electricity generated from heavy fuel oil now approaching 8¢ per KWH and the cost of light fuel oil going almost straight upwards, the need for energy solutions is immediate and indeed vital to the future economic development of the Island.

No society can survive without jobs, no jobs can be provided without industry, and no industry can hope to remain competitive and provide jobs when operating costs run wild.

The industrial base of P.E.I. consists primarily of processing plants for the two basic elements of any rural seaboard economy, i.e. farming and fishing. The quality of Island products is well known. Table stock and processed potatoes, lobster and quality dairy products from P.E.I. have captured a select and discriminating market throughout Eastern Canada and the eastern seaboard of the United States. The emphasis on quality does not come cheaply however, and when the high cost of quality is combined with the high cost of energy, both for processing and for transportation of goods to market, it is not difficult to envisage difficult days ahead for the Island processing industry.

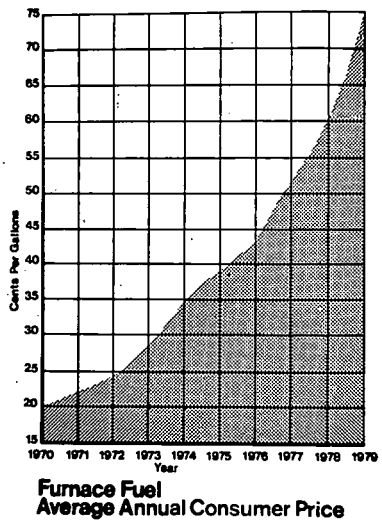


Fig. 2 Light Fuel Oil Costs on P.E.I.

The needs of industry on P.E.I. for better energy use management and energy cost control were identified over three years ago, and the provincial government in conjunction with the federal government of Canada signed an agreement to provide assistance to Industrial, Commercial and Institutional operators on the Island in an attempt to offset the growing concern over escalating energy costs.

Fig. 3 The Ener$ave Logo

The watch word was energy conservation or ENER$AVE as the program was called. The imaginative logo for the program, designed by a local firm, proved an instant success and now serves to identify energy conservation programs throughout Canada, including Quebec where the French version ENER$AGE is used.

The ENER$AVE program agreement provided funds to the province to operate a five element program. The key element to the program was the provision of an energy audit vehicle to provide on-site audit capability for all large operators. In addition the program called for assistance to clients through funds for consultant studies; grants for capital retrofit projects; thermographic analysis of heat loss; and workshops and training seminars in energy conservation for plant personnel.

The foundation of the program, however, was and still is the energy audit vehicle, or Ener$ave Bus as it is commonly known. This vehicle has become a familiar sight as it criss-crosses the Island on a busy schedule of visits which has resulted in a total of 310 sites audited, representing over 500 individual buildings ranging from the largest food processor on P.E.I. to small handcraft operators. To date a total of $10.2 million in energy bills has been audited which showed an average potential saving of 22%. Of even more significance are the results achieved in energy use reduction by firms who have implemented the bus audit recommendations. Savings of up to 65% have been realized with the average actual reduction being 12.5%. When applied to all audited clients this 12.5% reduction represents a total annual saving of $1.3 million.

The significance of this saving goes beyond the reduction in client operating costs. The saving represents a benefit to the province in that there is a reduction in the money which would have left the Island and the provincial economy to purchase imported energy supplies. Another direct benefit accrues to the federal government in that the reduction in energy use represents a direct reduction on dependence upon foreign oil imports and a saving of $800,000 annually in oil import compensation payments. The message is clear that energy conservation assistance programs pay off for all concerned.

But what is the means by which such results are achieved? The not so secret formula is a blend of high technology, skilled personnel and salesmanship.

The technology is manifested in a customized GMC Transmode. Starting with a chassis and an outer shell, the internal fixtures have been carefully designed to provide all the necessities and comforts required to make the vehicle a suitable venue for the stimulating, and sometimes highly technical, discussion of a client's energy options.

The heart of the 'Bus' is the computer system. The DATA GENERAL NOVA 3 RDOS system provides the key to unlock the energy secrets of any plant operator. The system, complete with 64 k memory, and both disc and discette data storage, has the flexibility to examine innumerable options at the request of operator or client alike.



Fig. 4 The Ener$ave 'Bus'

Seated in the conference centre at the back of the bus, which can accommodate six persons comfortably, the bus captain controls the flow of data through the video terminal. Supplemented by visual aids such as flip charts, the bus crew can massage the data to provide hard copy output on the DASHER printer. This output, by the way, is kept strictly

confidential to the client and remains with him when the audit is completed.

A computer is only as good as the internal programs it operates on. The set of computer programs which has evolved over the past three years is designed to evaluate any of six main areas of energy use within a plant. The basic analyses cover the following:

1. Insulation and Infiltration
2. H.V.A.C.
3. Electricity
4. Waste Heat Recovery
5. Process Steam and Hot Water
6. Inflation

These analyses are linked by a MASTER program which cues the operator and stores and totals the results for subsequent print-out. The program language is extended basic and all communication with the computer is in everyday conversational format.

Another important element is data. The importance of accurate data cannot be over stressed. Data submissions by clients prior to the audit are checked by the computer for accuracy and reasonableness and a cue sheet is generated which highlights for the bus crew the areas of plant energy use which must be more closely investigated.

Armed with the cue sheet the crew proceeds to work through the plant accompanied by the plant operators. This is the crew's opportunity to become fully familiar with the process and to make any last measurements. Among the items checked are combustion efficiency, operation of HVAC systems, electrical demand, control settings, and potential heat recovery options. It is here in the walkthrough that the second ingredient of skilled personnel proves its worth. The importance of the walkthrough has been demonstrated many times, as all too often plant personnel find out for the first time where their meters are located, which controls are out of calibration or wrongly set and numerous other problems which only a fresh, objective observer can pick out.

After the walkthrough it is time to return to the 'bus' and talk business.

It is now that the third part of the formula comes into play - Salesmanship. Up to now the crew has been engaged in assembling data and facts. Now they must convert the myriad of information into a believable picture of the client's energy state. Not only must they convince the client of the extent of his energy problem, but they must follow through with specific recommendations for action.

Seated in the bus conference area, away from the interruptions of telephones and secretaries, the crew has a captive audience and they proceed to run through the analyses of energy use.

Insulation and de-stratification are big energy savers for industrial operators in northern climates, especially with expansion of processing into the winter months.

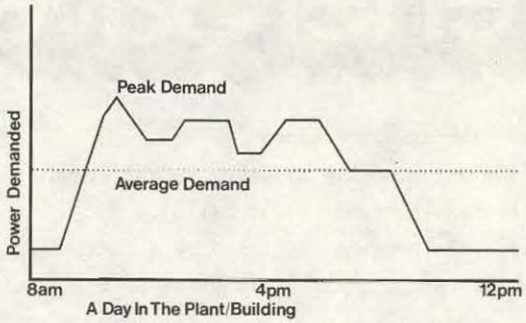


Fig. 5 Reduce the Peaks and Save

Peak demand analysis shows the potential benefits of load management and improvements to be gained in load factor.

Power factor correction is a generally misunderstood option that can result in significant dollar savings, although it does not reduce energy consumption.

Through one option after another the client is given the opportunity to see the potential savings 'if' he does certain actions. The savings are stored and tabulated at the end of the analysis process.



Fig. 6 Reviewing the Options

What Inflation Can Do To You!

Year	$ No Inflation	$ With Inflation	$ With Reduction	$ Savings
1	156,000	156,000	132,956	23,043
2	156,000	168,480	143,593	24,887
3	156,000	181,958	153,080	26,878
4	156,000	196,515	167,486	29,028
5	156,000	212,236	180,885	31,351
Totals	780,000	915,000	780,000	135,000

If the client remains skeptical a look at what inflation can do to his future energy bill is usually sufficient to convince the client of the need for action. Using the energy inflation rate suggested by the client, the computer calculates what percentage reduction in energy use is required immediately to allow the client to stay even on energy costs over the next five years.

Using the estimated potential savings for the client, it is now time to set an energy saving target which the client feels he can achieve.

An important visual aid in convincing the client of heat losses in his operation is the use of aerial and terrestrial infra-red thermography.



Fig. 8 Broken Steam Line at lower left.

All major sites are provided with an aerial thermography report which picks out problem areas in roofs, steam lines and insulated storage facilities. In the thermographs (Fig. 7) the areas of heat loss show up as white spots. The thermographs can be further interpreted to indicate evidence of structural problems, leaks and breaks, as is clearly shown in the picture (Fig. 8) of a steam main complex. Upon digging up the suspect area, a break in the steam main was repaired and resulted in an $80,000 annual saving on energy losses and make-up water treatment costs.

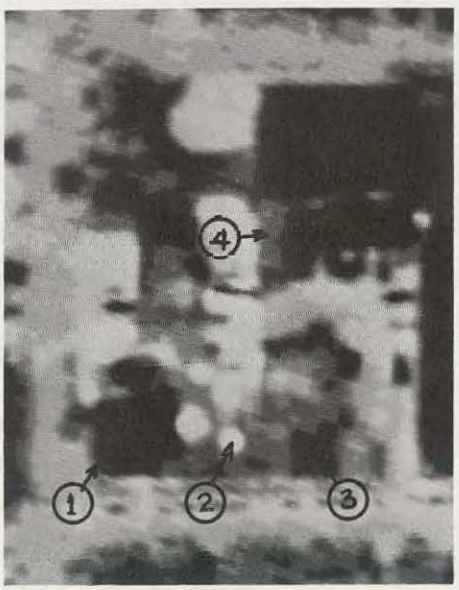




Fig. 7 Aerial Thermogram of Amalgamated Dairies Plant Showing:

1. Insulated office area.
2. Exhaust Vent.
3. Unheated area in storage building.
4. Damaged roof insulation.

A portable infra-red camera is used to provide additional analyses from ground level of such things as wall insulation, electrical wiring, motor bearings circuit breakers and electrical sub-stations. Quite often the Inframetrics Series 510 unit will pick up potential trouble spots, such as overheated connections and bearings, which could cause considerable expense and delay in plant shutdown. An important feature of the Inframetrics unit is the capibility to record the infra-red scan on video tape and play it back in the bus for the client.



Fig. 9 The Inframetrics Portable Infra-Red Unit.

The audit visit is now complete and the computer summarizes the findings on the cover-page of the report printout. The work of the audit crew, however, does not end at the site. They must now prepare a written report of their findings and recommendations for both the program management and the client. It is this report that forms the basis for whatever grant support the client will be eligible in implementing the recommendations.

The final report is mailed to the client after the recommendations have been verified by the program technical staff and includes instructions on how the client may contact consultants or apply for the available grants.

A review of an actual bus audit report and the subsequent actions of the client serves to illustrate the process which resulted, in this particular case, in the client more than doubling his production while holding his energy costs constant.



Fig. 10 Cheese Production at Amalgamated Dairies.

Amalgamated Dairies is a fluid milk and cheese processor located in Summerside, P.E.I. One of the first firms on P.E.I. to get an audit, they have also been among the first to show significant results.

The original bus audit in November, 1977 was somewhat of a disappointment in that a potential saving of only 6.3% was identified. The audit report, however, stressed that due to the nature of waste heat losses and the age of the heating plant there was much difficulty in determining economically justifiable potential savings without further detailed study. On the basis of the visit sufficient interest was shown by plant management to warrant a more detailed review. A grant of almost $35,000 was made available to the firm, based on the potential savings and the firm's total energy use. One-sixth of this grant could be used to fund a consultant study of the premises and an appropriate consultant was duly selected.

The consultant report showed considerably more energy savings potential and was able to calculate the cost of the various options considered.

This type of situation points out the major drawback of the bus audit program. It is clearly impossible to give detailed recommendations on the basis of a one-day visit and some quick computer analyses. The provision of consultant assistance subsequent to the audit is an important incentive to encourage firms to follow through on the audit recommendations, limited as they are.

The summary list of recommendations was as follows:

Electrical	Annual Saving	Installed Cost
Improve power-factor from 75% to 95%	$ 4,000	$ 8,000
Install single electrical entrance with selective load shedding	7,000	60,000
Heating		
Replace existing low efficiency boiler	5,300	85,000
Insulation		
Insulate high pressure steam lines and condensate return lines	9,700	13,000
Insulate hot process tanks	600	2,500
Heat Recovery		
Condensate Recovery	750	1,500
Miscellaneous		
Insulate and close off windows	2,400	4,000
Replace Incandescent with Fluorescent fixtures	3,000	3,500
Reduce operating hours for high pressure wash system by installing timer	850	800
Total	$33,600	$178,300

A simple payback calculation yields a payback of 5.3 years which does not include additional savings in maintenance costs on the new heating and lighting systems, or any escalation in energy costs.

The $33,600 saving represents a 37% potential reduction in the client's annual energy bill of $90,000.

Armed with the audit report, the consultant report and the promise of a $35,000 grant, the plant manager quickly obtained approval for the necessary retrofit actions and the results two years later are dramatic and very satisfying. From an energy cost of 1.5 cents per dollar of gross sales the plant has cut energy costs to 0.7 cents out of every sales dollar. What this means is that while annual plant throughput has more than doubled the total annual plant energy costs have remained the same.

The success of this industrial operator among others in reducing energy use has triggered a growing demand for the Ener$ave audit services and related grants. The six week backlog of clients awaiting audits is testimony to the fact that:

ENER$AVE IS GOOD BUSINESS

HIGH-EFFICIENCY BURNERS

BY RETROFIT - A SIMPLE INEXPENSIVE WAY

TO IMPROVE COMBUSTION EFFICIENCY

Will T. Rogers

Coppus Engineering Corporation
Worcester, Mass.

Existing direct fired process heaters and steam boilers can have their efficiencies remarkably improved, and thus cut the fuel bill, by conversion from conventional type natural draft burners to high intensity, "forced draft" type burners. An available type that is "forced draft," but which does not require expenditure of energy for forced draft, will be discussed.

Combustion Air is automatically controlled by the fuel flow - which fuel drives the "forced draft" fan to control airflow.

Use of such type burners can, in many instances, increase efficiency to a point close enough to that obtainable by addition of air preheat until the difference in efficiency with air preheaters will not justify the high cost of air preheat systems.

Low excess air and short, high intensity flame patterns assure reduction of stack temperature, thus increased efficiency.

Conversion can be made "on-the-fly" without shutting down the fired heaters or boilers by insertion of an "installation package" of the burners into openings left after removal of conventional burners.

Energy conservation is a vital concern of industry today. Most people are aware that we are now experiencing the sunset of an age during which fossil fuels in the form of natural gas and oil were found in ample supply at low cost. As a result, conservation of these two fuels are receiving high priority.

In this paper we shall address ourselves to the conservation of these fuels by increasing the efficiency of fired heaters, particularly existing fired heaters, by using the technique of retrofit to available high efficiency burners, a simple, inexpensive way to improve combustion efficiency and thus conserve fuel.

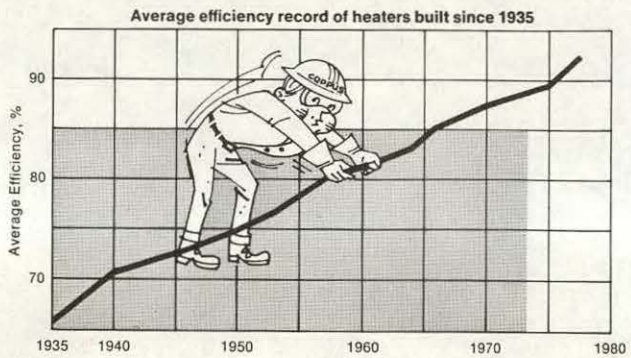
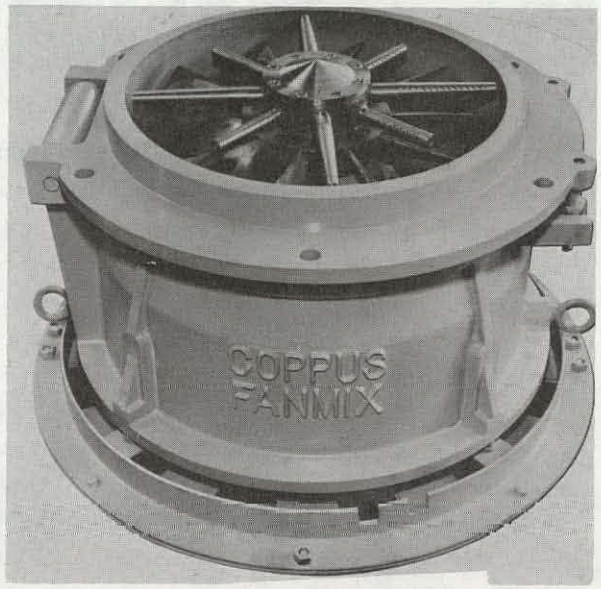


FIG. 1

Figure 1 gives an average efficiency record of heaters built since 1935 to present. Note the to-be-expected heater efficiency improvement as time went on from a low of around 60% to the range of 87% today. Note, however, the shaded area. This represents the average 75% efficiency of heaters constructed over the same period. If your process heaters were built during one of the years in the shaded area, replacing conventional burners with modern "forced draft" type design burners that provide high intensity flame patterns, but which do not require expenditure of energy for driving of forced draft fans, can upgrade your existing heater efficiencies as much as 10% or more. In some cases, as high as 15% has been accomplished. (Note the shaded area ends at 1973 with the event of OPEC.) For purposes of discussion in this paper, heaters to be considered for retrofit are those of conventional design perhaps including some convection surface, but many cases no convection surface, and without preheated combustion air.

An available burner of the type described as being "forced draft" but without requiring energy for driving a forced draft fans is as shown in

figures 2 and 3, in the vertical and horizontal configurations respectfully. This is a rotary burner equipped with a fan for providing forced draft and for proportioning of fuel and air, but which fan is driven by the reaction force of the fuel discharging from the burner driver arms on the equal and opposite reaction principle and as shown in figure 4 with the burner driver assembly held stationary with steam escaping from the fuel discharge ports for photogenic purposes.



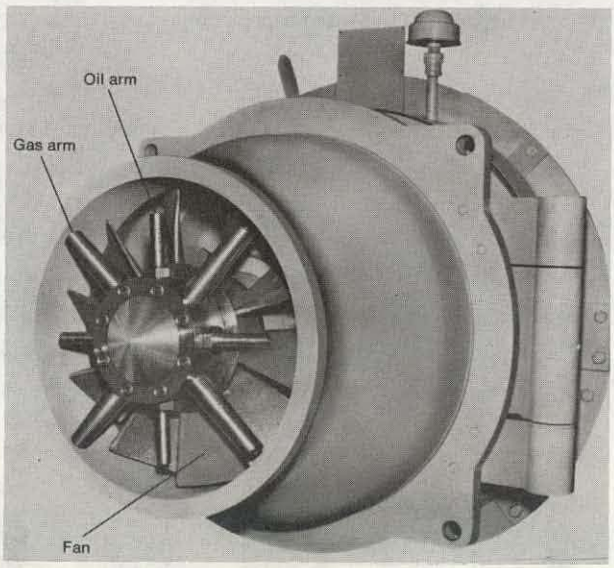


FIG. 3 HORIZONTALLY FIRED BURNER

This pinwheel action of figure 4 results in development of a sheet of fuel imposed across the fan-driven air stream and provides for the ultimate in mechanical mixing of fuel and air, while at the same time allowing for operation at an absolute minimum of excess air due to this superior mechanical mixing of fuel and air.

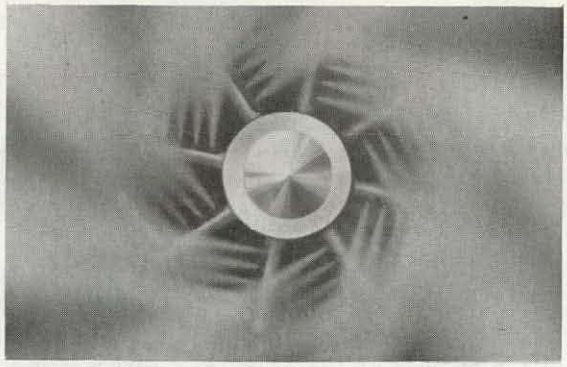


FIG. 4

The resulting flame pattern is as shown in figure 5, which is typical of a high intensity forced draft burner. Conventional forced draft high intensity burners require expenditure of energy to drive their forced draft fans as compared to no energy required for this type of burner.

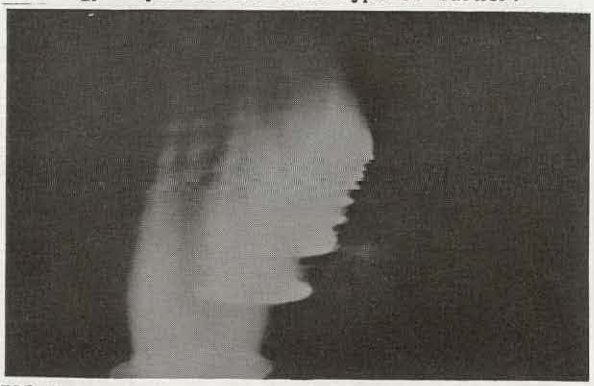


FIG. 5

A comparison of the high intensity flame pattern of figure 5 with the flame pattern from conventional design natural draft burners is shown in figure 6. Many times attempting to fire these class burners at higher ratings or at attempted low excess air operation results in long, poorly-defined flame patterns as compared to the high intensity flame of figure 5.



FIG. 6

Maintaining control of combustion air and fuel is many times poorly done with conventional burners as there is, really no "control" over this ratio. Conventional burners depend upon furnace draft to pull air through the burner openings, and across the fuel discharge ports. Changes in firing rate of furnaces are not compensated for in fuel air ratio by conventional burners. Figure 7 shows the characteristics of the rotary type burner, where due to the reaction of the fuel discharging from the rotating arms providing the driving power for the forced draft fan, fuel and air are automatically proportioned with any change in firing rate, without operator attention or without expensive control louvers, dampers, or other control equipment. The reaction force shown in figure 4 is what causes this unique relation of fuel and air with this design burner.

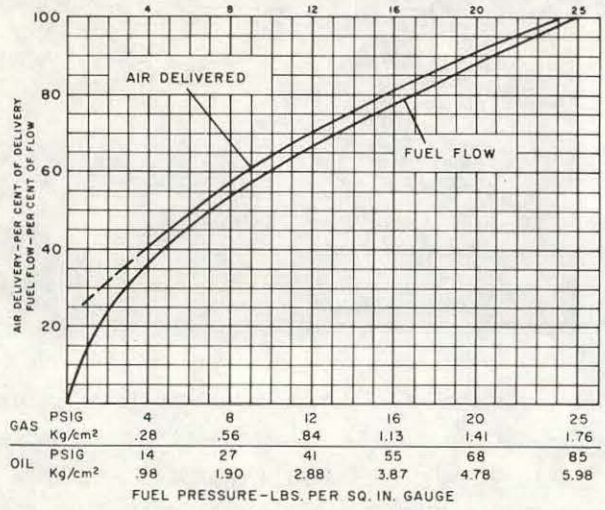


FIG. 7

Control of fuel and air with superior mechanical mixing of fuel and air results in the possibility of operating at extremely low excess air. The high intensity flame pattern assures that the position of the flame in the furnace (refer to figure 5) is such that all of the tubes in the furnace get a chance at the radiant heat of the flame as opposed to longer disorganized flames (refer to figure 6), all of this resulting in lower stack temperature and lower fuel consumption.

Figure 8 shows 2 gas flow charts. These are actual operating charts taken from fuel gas meters on a fired heater at a plant of one the major producers of natural gas. The chart on the left

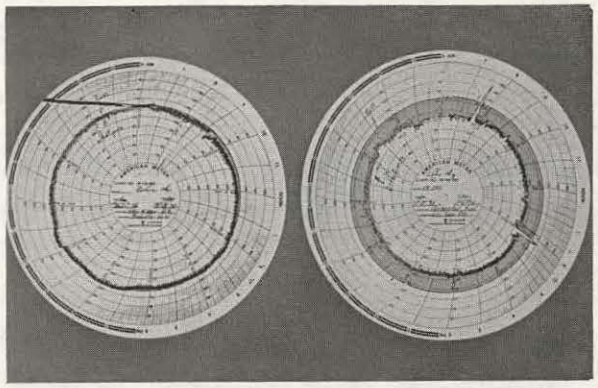


FIG. 8

shows the differential and pressure curves of the heater being fired with conventional burners prior to conversion to the high intensity type burner under discussion, and the chart on the right shows the relation of the differential and pressure curves. This particular heater is reflecting a 15% fuel savings.

In attempting to fire heaters with conventional burners at elevated ratings, normal to the industry where ratings almost always exceed original design, figure 9 shows the draft loss condition depending upon draft to pull air through them, as a clenched fist on the airflow. (Refer to figure 6 for typical flame patterns resulting from this condition). On the right we show the clenched fist opened, showing no draft loss across the high intensity forced draft burner under discussion, which eliminates the flame patterns typical of figure 6 and insures flame patterns typical of figure 5. At the same time, heaters can be fired at elevated ratings without flame impingement problems, and with high efficiency due to low excess air and proper placement of flame in the furnace for proper heat distribution in the furnace.

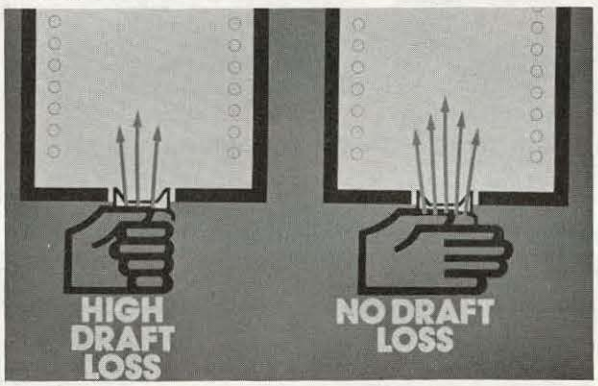


FIG. 9

Additional efficiency is assured by greater enhancement of downflow of combustion products behind tubes, between them and the walls as shown in figure 10. The high velocity discharge of the high intensity forced draft type burner creates the recirculation pattern in the furnace as shown with the result that more of the tube surface is used by heat absorption on the backside as well as absorption by exposure to the radiant flame on the flame side of the tubes.

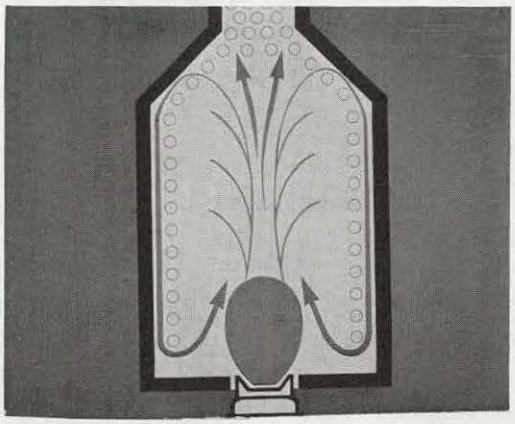


FIG. 10

Expected increase in efficiency by retrofit is shown in figure 11. As discussed previously, proper flame placement in furnaces result in lower exit gas temperatures and lower stack temperatures, while at the same time reduction of excess air, also results in reduction in fuel consumption. Normally, reduction in stack temperature of 100°F is commonplace and many times more than this, and reduction of excess air is commonplace from 30% with conventional burners down to 10% or less with the more efficient type burner. Figures can be taken from existing furnaces, operating data, and applied to this curve and fuel savings shown.

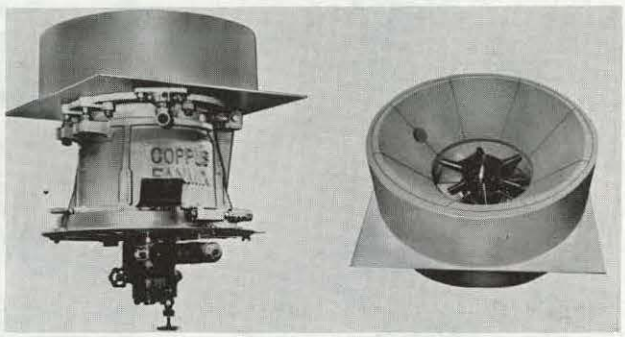


FIG. 12

Retrofit or conversion of existing fired heaters from conventional design burners to the high intensity forced draft type burner is a relatively easy matter. Figure 12 shows an "installation package" that can be made up of the burner with burner tile, pilot burner, and other accessories.

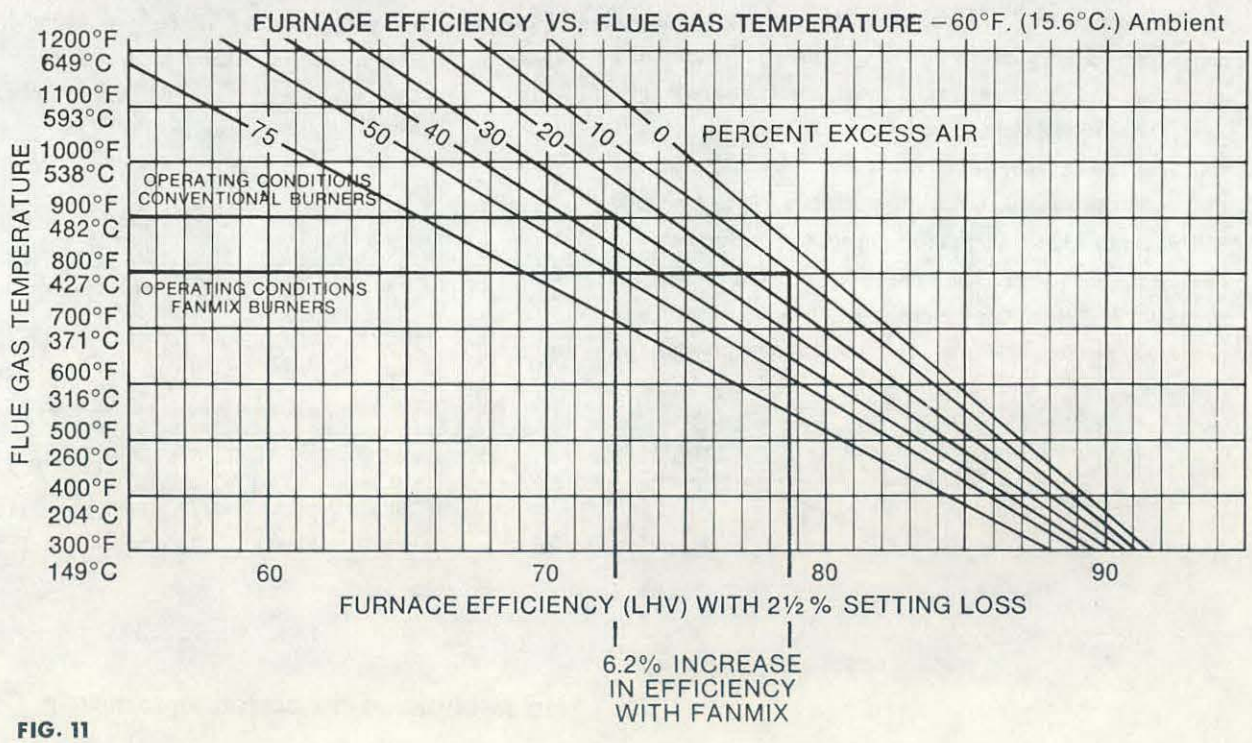


FIG. 11

Figure 13 shows a converted fired heater where the installation packages were inserted into openings left after removing existing conventional burners. Note the blocked-off, circular openings formerly occupied by the conventional burners and the installation of the high intensity forced draft type burners in alternate openings. This further illustrates the possible economies of these retrofits by the fact that the flame pattern of the high intensity type burner allows for using fewer burners at higher individual burner heat releases still without impingement problems.

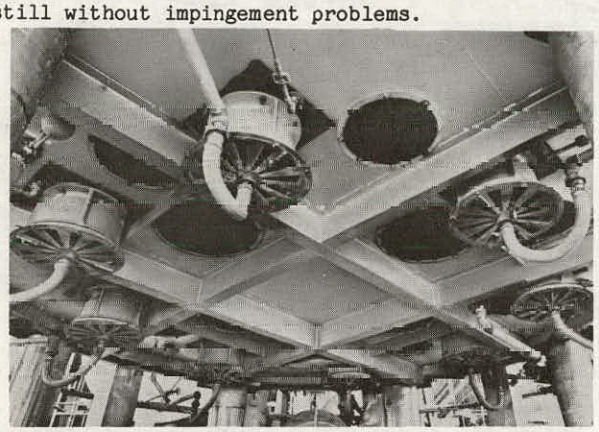


FIG. 13

Figure 14 shows one of the amazing characteristics of this reaction-driven forced draft type burner. Even with variable BTU value fuel gas, many times typical to petroleum refinery operation, the relation of fuel to air is maintained nearly constant. Even though operating fuel pressure will vary as BTU value of fuel gas changes, and with a fixed heat release requirement, thus requiring a constant air supply, nevertheless the higher BTU value of fuel gas, as in the case of going from 800 BTU/cu./ft. to 1200 BTU/cu./ft. has a higher specific gravity, is heavier, and thus the reaction force principle even at a lower fuel pressure with a denser gas provides remarkably near the same drive power.

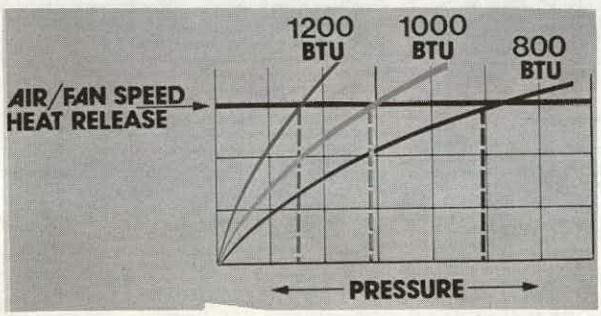


FIG. 14

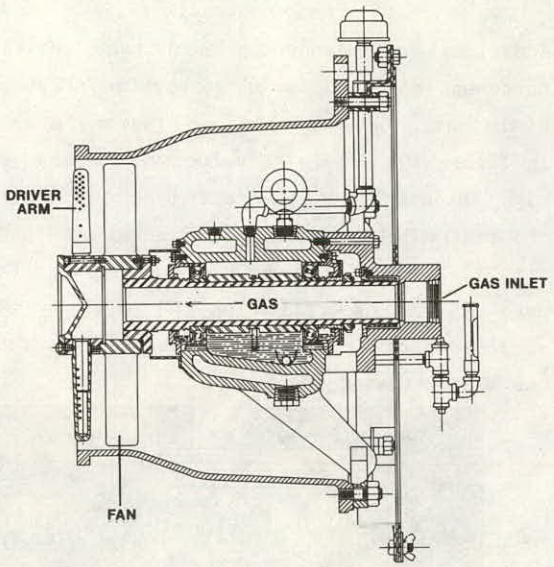


FIG. 15 GAS FIRED BURNER

The mechanical construction of the burner is shown in the straight gas configuration of figure 15. Gas goes through the center shaft and out through the driver arms driving the burner fan to provide the fuel air relation of figure 7.

Figure 16 shows the combination gas and oil burner configuration where there are concentric shafts, oil going through the center most shaft, steam around this shaft to be used for steam atomization and for driving the burner fan with the mixture of atomized steam and oil, and then an outer shaft through which gas passes. There are separate gas arms and oil arms, thus making this a burner capable of firing any percentage of the 2 fuels in true combination simultaneously.

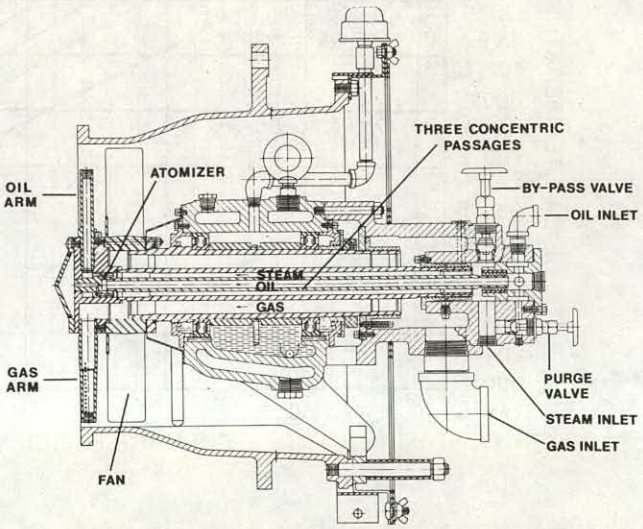
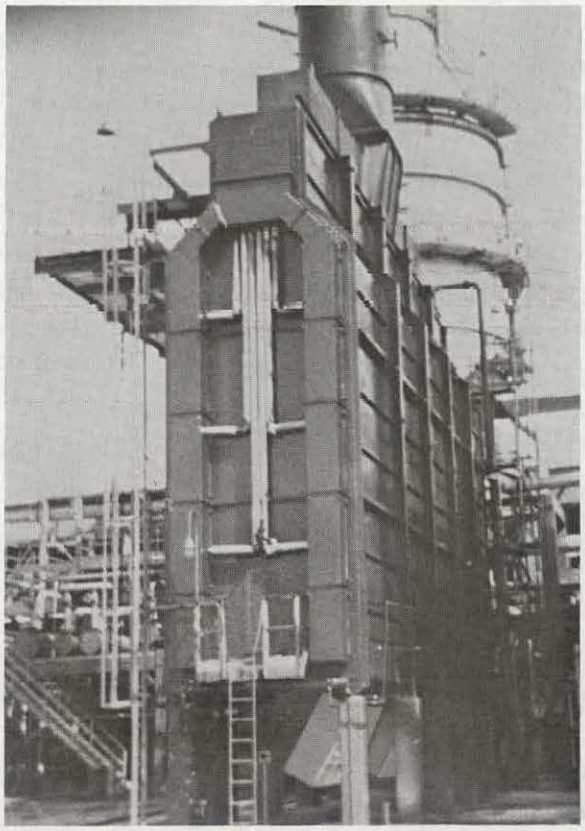


FIG. 16 COMBINATION GAS/OIL FIRED BURNER

Another typical heater conversion is shown in figure 17. This is a petroleum refinery crude vacuum heater in one of the major refineries that was plagued with poor flame patterns firing liquid fuel as shown in figure 18. This resulted in frequent tube failures and unnecessary downtime.



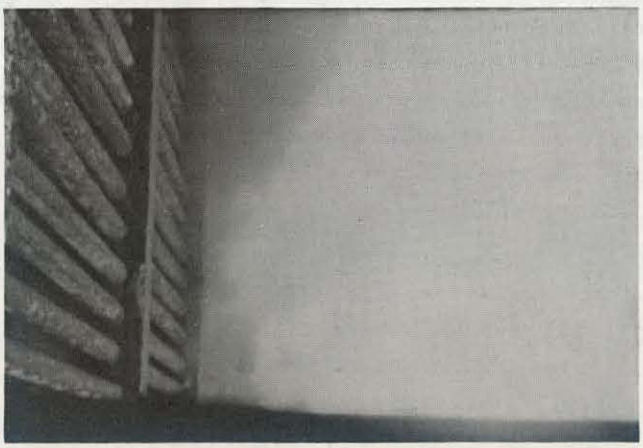


FIG. 18

The conventional type burners providing the flame of figure 18 were replaced with forced draft high intensity type burners under discussion and the flame provided was as per figure 19. Here the short, compact high intensity type flame is clearly shown eliminating flame impingement problems and providing proper heat release location in the furnace to give all of the tubes a chance at the radiant heat rather than having long extended flames with too much heat release toward the top of the furnace resulting in high stack temperatures. The burners shown are operating at 10% excess air firing 100% fuel oil.



FIG. 19

Conversion to the forced draft type high intensity burner affords the availability of greatly increasing furnace efficiencies without the great expenditure for providing furnaces with air preheaters for preheating combustion air. Admittedly, the application of costly air preheaters may provide greater efficiency than that achieved with the "forced draft" type burner. However, the difference is usually small, many times only 3 to 5 percentage points, that the added expenses of preheaters and the extended pay-out is not justified.

Of interest will be that in many cases conversions are actually made "on the fly" without shutting down heaters, and thus no production time is lost. (The installation of figure 13 was made with the heater on-stream.)

OPERATING EXPERIENCE OF A COAL-FIRED FLUIDIZED BED AT GEORGETOWN UNIVERSITY

Ian G. Lutes
Robert L. Gamble
Foster Wheeler Boiler Corporation

Livingston, New Jersey

ABSTRACT

Operation of the 100,000 lb/hr capacity, coal fired fluidized bed steam generator at Georgetown University began in July 1979. This project, which was co-funded by Georgetown University and the U. S. Department of Energy, involved expansion of the heating and cooling plant with this new coal fired facility. Previously existing units at the University heating and cooling plant normally fire natural gas.

The fluidized bed steam generating facility at Georgetown University is the only new coal fired facility to be built in the Washington D. C. area in many years. The purpose of this program is to demonstrate industrial and institutional application of fluidized bed combustion using high sulfur coal in an environmentally acceptable manner in a populated area. The unit has been successfully operated for over 1400 hours and in compliance with the strict emission regulations of Washington, D.C. Operation on automatic control has been achieved and only minor operating difficulties have been experienced.

PLANT SITE INFORMATION

The 116 acre campus of Georgetown University contains approximately 2.2 million square feet of buildings which are served by a central heating and cooling plant. Figure 1 shows a portion of the campus and indicates the heating and cooling plant located adjacent to the sports facilities.

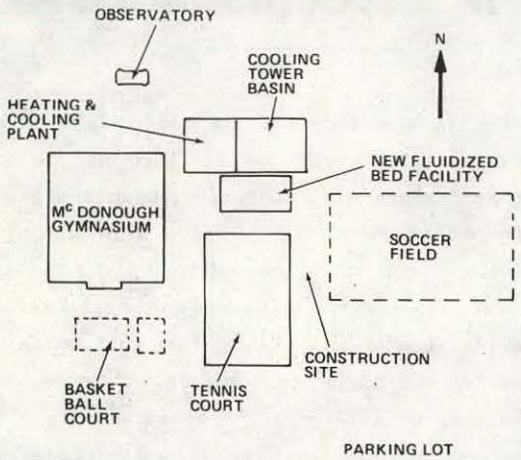


FIGURE 1: FLUIDIZED BED FACILITY SITE PLAN

Strict building codes required the fluidized bed facility to conform with the University architectural standards. The fluidized bed facility building is shown adjacent to the tennis courts in Figure 2.

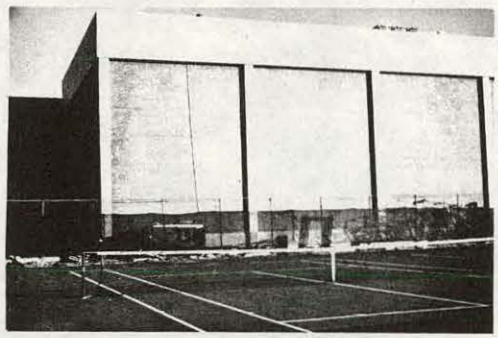


FIGURE 2: FLUIDIZED BED FACILITY BUILDING

STEAM GENERATOR DESIGN

The fluidized bed steam generator, shown in Figure 3, is designed for natural circulation to generate 100,000 lb/hr of saturated steam at pressures from 275 to 625 lb/sq.in. The unit normally operates at 275 lb/sq.in. in accordance with the steam system requirement. The capability for the higher pressure operation was requested by DOE for future co-generation. Design parameters for the steam generator are listed in Table 1.

The natural circulation design includes four external downcomers to supply lower headers, partition walls and inclined tubes within the fluidized bed. Flue gases are cooled by a conventional boiler bank in which the cold end tubes act as downcomers and the remaining tubes are steam generating risers. All heat transfer surface in the steam generator is fabricated from carbon steel.

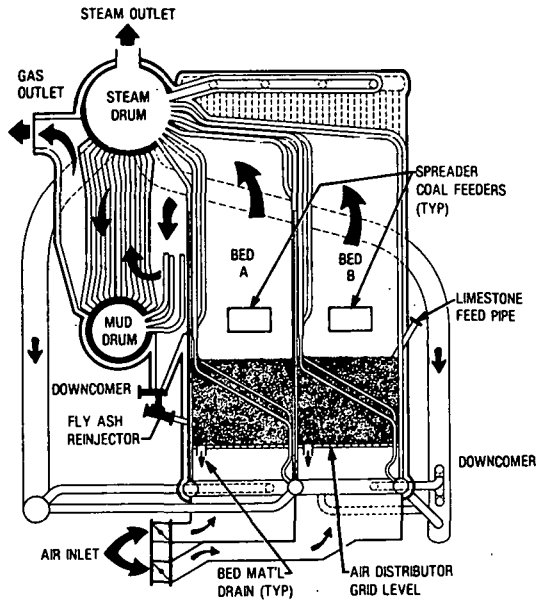


FIGURE 3: STEAM GENERATOR ARRANGEMENT

TABLE 1 - STEAM GENERATOR DESIGN PARAMETERS

Steam Flow	100,000 lb/hr
Steam Condition	275-625 psig, saturated
Feedwater	228F
Bed Dimensions	5ft. 6in. x 19ft. 4in.
Bed Height	4ft. 6in.
Bed Temperature	1600F
Fluidizing Velocity	8ft/sec
Freeboard Height	8ft.
Calcium/Sulfur	3/1 (Molar Ratio)
Coal Flow	9565 lb/hr
Limestone Flow	3133 lb/hr
Bed Removal Flow	1000 lb/hr
Flyash Flow	1308 lb/hr
Design Coal	Bituminous
Heating Value	12,750 Btu/lb
Ash	7.97%
Moisture	5.0%
Sulfur	3.29%
Volatile Matter	38.93%
Fan Power	475 HP
Efficiency	83.51%

The unit is designed for a four to one load turndown using two independently fired fluidized beds, each capable of two to one turndown. Each bed has a plan area of 106 square feet and operates at 1600F with an 8 ft/sec fluidizing velocity. The excellent heat transfer characteristic of the fluidized bed permits approximately 50% of the total unit heat transfer to occur within its 4½ foot height.

Coal, sized to less than 1¼ inch, is injected to each bed with overbed spreader feeders of the same type used on spreader stoker steam generators. These feeders do not require coal drying. Limestone is fed by gravity at a single point in each bed and is sized to less than 1/8 inch. Due to the long residence time of the limestone in the fluidized bed and the rapid burning rate of the coal less than five percent of the bed consists of fuel.

Since the fluidized bed temperature of 1600F is below the fuel ash softening temperature, no slag formation occurs and there is no need for soot blowers required on other types of coal fired steam generators. The absence of slagging provides the owner with considerable freedom in fuel procurement practices.

Unit light-off is achieved by preheating a zone in each bed using 4,000,000 Btu/hr oil fired ignitors located between the air distributor and inclined tubes in the fluidized bed. The zone at the end of the fluidized bed near the ignitor, designated the start-up zone, can be independently fluidized with separate air dampers. To initiate coal firing, approximately 600 pounds of coal is fed into the bed with the overbed feeder and mixed by fluidizing the bed. The bed is then defluidized and approximately 70 pounds of coal is added to the start-up zone resulting in a surface fire near the ignitor. The start-up zone is then mixed by periodically fluidizing and allowing the surface fire to re-establish to raise the start-up zone temperature to 1200F. Upon reaching 1200F in the start-up zone, the main air damper for the rest of the bed is slowly opened and combustion propogates through the rest of the bed. Once the bed achieves a temperature of 1200 - 1400F, the spreader feeder is put into service and bed temperature is stabilized at 1600F.

The second fluidized bed, bed B, may be ignited through the same procedure or by means of a slide gate which allows hot bed material from bed A to pass through an opening in the partition wall. Both methods have satisfactorily been used to ignite bed B and a faster light-off time is achieved in bed B by using the slide gate method. Light-off of bed B with the slide gate method takes approximately ten minutes.

To maximize coal combustion efficiency, flyash reinjection from an internal cinder trap in the boiler and an external mechanical dust collector is used. This is similar to flyash reinjection in a stoker type unit. The flyash reinjection occurs in bed A and for this reason, bed A is always the first to start-up and the last to shutdown in the operating sequence. Reinjected particles are fed to bed A near the air distributor so they will pass through the fluidized bed to maximize opportunity for combustion.

AIR-GAS SYSTEM

The general arrangement of the Georgetown facility is indicated on Figure 4. The steam generator is designed for balanced draft operation with air flow from the forced draft (FD) fan controlled by dampers for each bed (Figure 3). The FD fan provides sufficient pressure to force the combustion air through the air distributors and fluidized bed.

The unit draft is balanced at the surface of the fluidized beds and the induced draft (ID) fan provides the necessary suction to draw the flue gases through the boiler bank, mechanical dust collector, economizer and baghouse prior to discharging to the stack.

FUEL SYSTEM

To satisfy environmental and aesthetic considerations, coal is delivered in covered trucks and unloaded inside the building shown in Figure 2. The coal receiving, storage and feeding system is indicated in Figure 5. The coal bunkers are designed for mass flow to minimize particle size segregation and have nine days storage capacity at full load operation. The coal is screened and particles greater than 1¼ inch are properly sized with a crusher. The coal screening before crushing minimizes generation of fine particles which are detrimental to steam generator performance. A coal surge bin is provided above the spreader feeders and a low level indication in the surge bin automatically initiates operation of the bin fill system.

LIMESTONE SYSTEM

Limestone is received, presized to -1/8 inch, in pneumatic discharge type trucks. Truck discharge blowers convey the limestone to the limestone bunker as shown in Figure 6. The limestone bunker is designed for mass flow similar to the coal bunkers and holds ten days supply at full load operation. Limestone from the bunker is pneumatically transported to limestone bins above each fluidized bed. Discharge from each bin is measured by weighbelt scales before falling by gravity to the fluidized bed. Limestone flow is regulated as a ratio of the coal flow and this ratio is adjusted by the automatic control system to control SO_2 emissions at the stack.

BED MATERIAL REMOVAL SYSTEM

Bed material leaves the fluidized bed by gravity through a pipe that vertically penetrates the air plenum and air distributor. Bed material flow rate from each bed is controlled and cooled by a variable speed water cooled screw device. The arrangement of this system is indicated in Figure 7.

At DOE's request, the Georgetown University facility is equippped with a crusher to break up the bed material rejects to expose the particle core which contains unreacted calcium oxide. This will increase the particle reactivity for possible by-product sales.

Bed material discharged from the screw coolers is pneumatically conveyed to the crusher, then to a storage silo within the building. Spent material is discharged to trucks in the coal receiving bay for removal.

FLYASH SYSTEM

As shown in Figure 8 flyash from the fluidized bed is first passed through a cinder trap before the boiler bank to separate the coarse particles and collect them in five hoppers across the boiler width. These particles are reinjected to bed A using eductors to draw them from the hoppers and blow them pneumatically into the fluidized bed.

The cyclone dust collector ahead of the extended surface economizer collects the smaller particles and five eductors pneumatically injects them to bed A. Particles not collected in the cyclone dust collector pass over the economizer to the high efficiency (99.75%) baghouse dust collector. Particles collected in the baghouse are pneumatically conveyed to the ash silo within the building and are periodically discharged to trucks in the coal receiving bay for removal.

CONTROL SYSTEM

The fluidized bed facility includes a combustion control and safety interlock system that is typical for industrial coal fired facilities. The control system provides for automatic control between 25% and 100% load with operator action required only at approximately 50% load to light-off or shutdown bed B.

The safety interlock system will automatically shut the system down in the event of loss of any critical operation component or in the event of inability to control bed temperature or furnace pressure.

The control system is in service and automatically controls the entire system to follow the University load demand signal. Some adjustments to the control system are still in progress to improve load-following during rapid load changes. On automatic control, all aspects of the system are controlled as required to maintain the proper steam flow while maintaining stack emissions with the Washington D.C. limits.

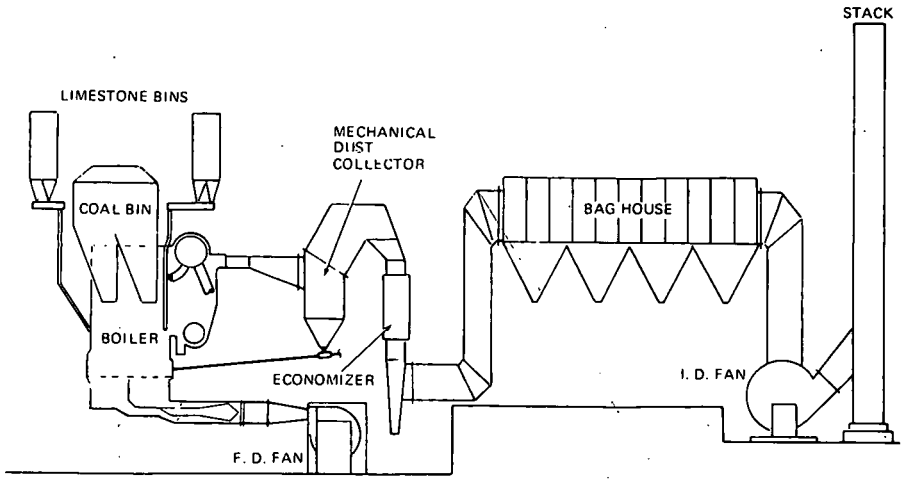


FIGURE 4: GENERAL ARRANGEMENT

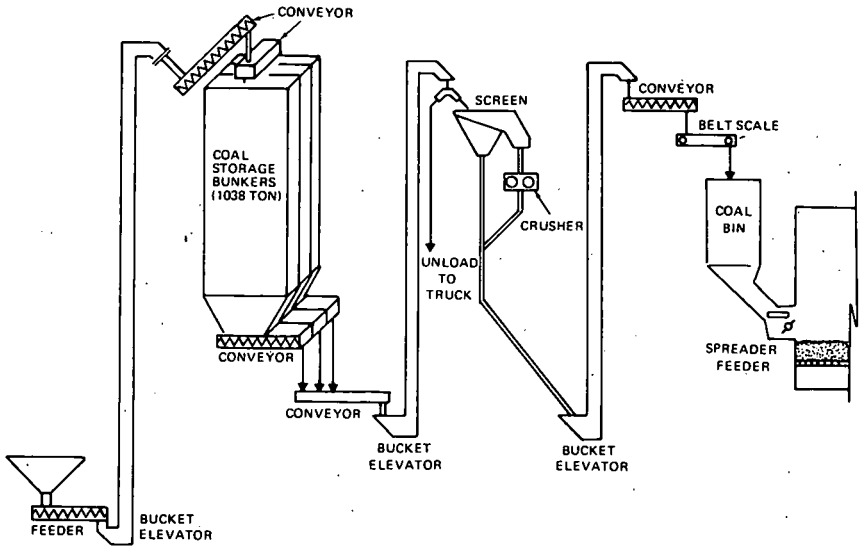


FIGURE 5: COAL SYSTEM

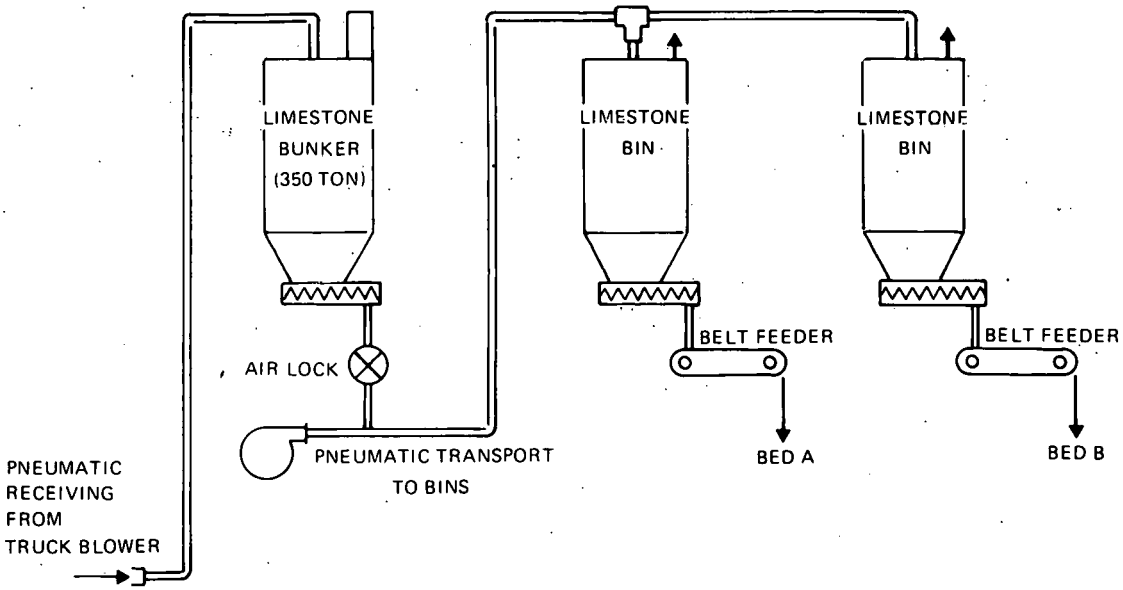


FIGURE 6: LIMESTONE HANDLING SYSTEM

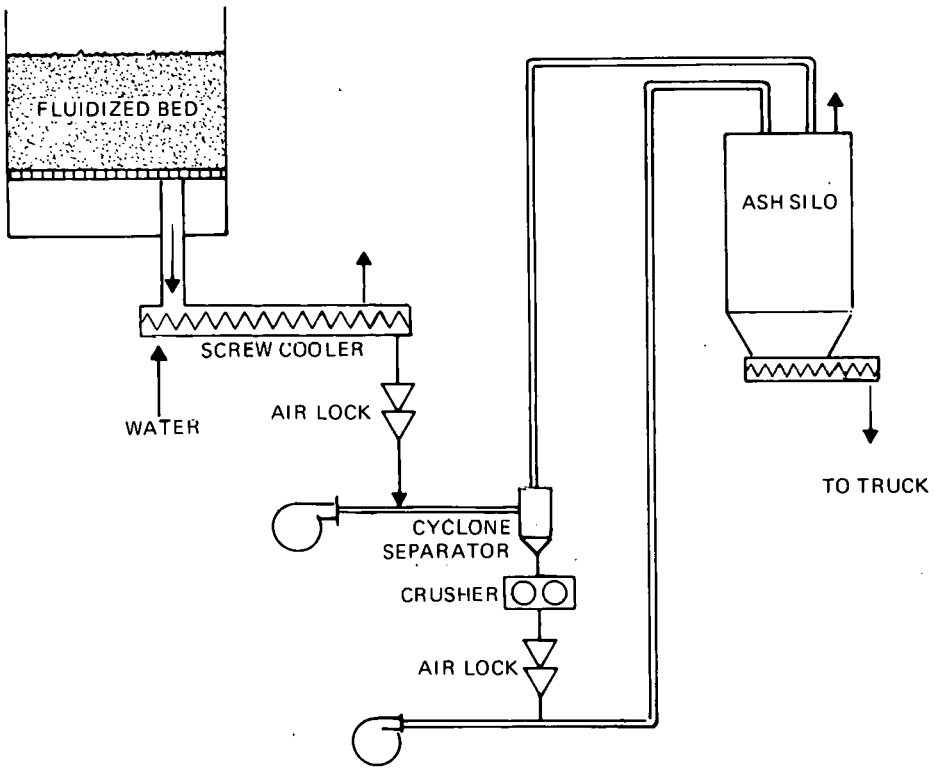


FIGURE 7: BED REMOVAL SYSTEM

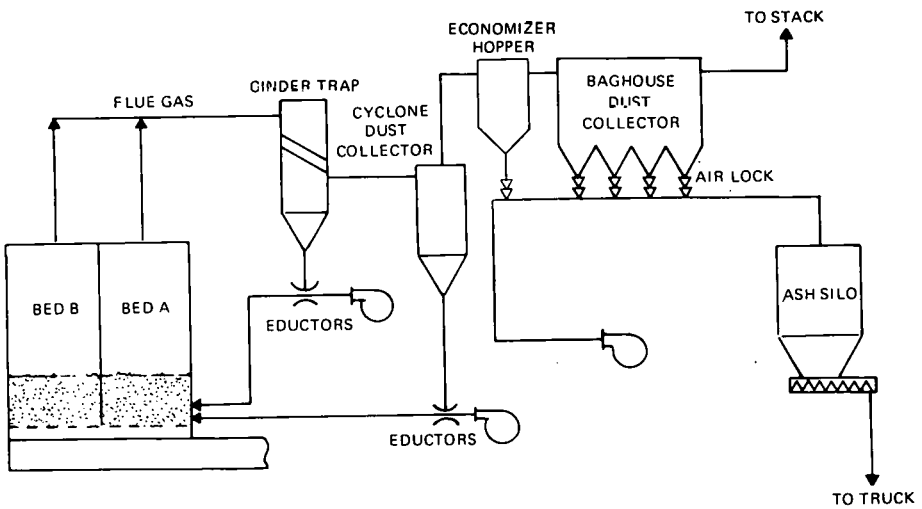


FIGURE 8: FLYASH SYSTEM

EMISSIONS CONTROL

Combustion of coal in a fluidized bed of limestone can result in control of SO_2, NO_x and particulate emissions within the federal and most state and local emissions limits. During operation at Georgetown University these emissions are controlled within the strict Washington D.C. limits without difficulty.

SO_2 emissions control is achieved by maintaining the fluidized bed temperature at 1500F to 1600F and operating with limestone bed material. The raw limestone ($CaCO_3$) calcines to lime at the bed operating temperature. The lime (CaO) reacts with O_2 and SO_2 released during coal combustion and forms gypsum ($CaSO_4$) on the surface of the particles. Affinity for sulfur capture is maintained by continuously feeding limestone and maintaining proper bed inventory with the bed material removal system. NO_x emissions are low due to the low temperature of the fluidized beds. Particulate emissions are maintained low by using a baghouse dust collector designed for 99.75% removal efficiency. Operation of the baghouse has shown excellent particulate removal resulting in very low stack opacity and no visible plume.

Figure 9 indicates the overall SO_2 reduction projected for various bed temperatures. The point indicated on Figure 9 shows the SO_2 reduction measured in a preliminary test on December 5, 1979.

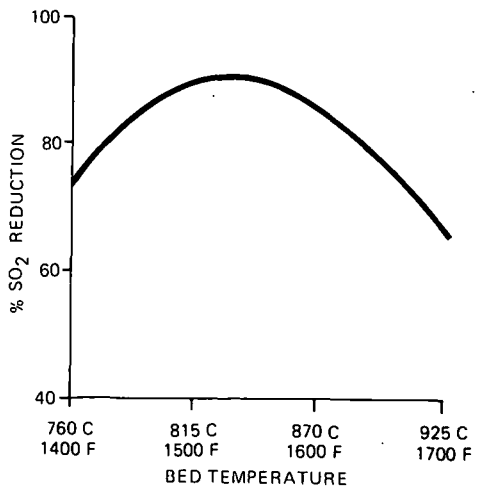


FIGURE 9: SO_2 CAPTURE VS. BED TEMPERATURE

The emissions limits established by Washington, D.C. and the U.S. EPA are indicated on Table II. The Washington D.C. regulations require continuous monitoring of SO_2, NO_x and stack opacity. Operation at Georgetown University has been within these limits at all times except occasional momentary periods during operating upsets.

TABLE II - STACK EMISSIONS

Emission	EPA Limit	Wash. DC Limit	Measured 12/5/79
SO_2 (lb/10^6 Btu)	1.20	0.78	0.48
NO_x (lb/10^6 Btu)	0.70	0.70	0.30
Particulates (lb/10^6 Btu)	0.10	0.056	-
Stack Opacity (%)	20	20	17*

*High reading, opacity range is 4-17% with an average of approximately 10%

Emissions data from December 5, 1979 are indicated on Table II adjacent to the existing limits. These emission levels were obtained while firing coal containing 2.3% sulfur.

OPERATING EXPERIENCE

Unit operation began in July 1979 and 1370 hours of operation were accumulated through February 1980. This operation has been with 1 and 2 beds in service and included a maximum capacity of 80,000 lb/hr. During several operating periods the fluidized bed unit was the only boiler in service and supplied the total University steam flow while following the system demand. The unit was initially started with low sulfur coal and quickly switched over to the higher sulfur coal for which it was designed. The actual coal burned differed slightly from the design basis since the sulfur content was lower and the ash content higher than the design fuel. Examples of the as delivered coal are shown in Table III. The size analysis indicated on Table III represents the coal at the truck receiving hopper and does not reflect particle size degradation within the plant. Examples of the as delivered limestone size analysis are shown on Table IV. The typical limestone contained approximately 97% calcium carbonate with the remaining portions as ash and moisture.

The following gives a brief description of the operating experience with each of the major systems:

Steam Generator

No significant difficulties have been experienced in operation of the steam generator. Some initial leaks around the perimeter of the air distributor were readily sealed and the air distributor has performed close to design expectations. Although there are no soot blowers in the system, ash build-up on the tubes has not occurred and cleaning has not been necessary. The flyash from the fluidized beds has not adhered to the heat transfer tubes because of its dry friable nature.

TABLE III - AS DELIVERED COAL ANALYSIS

	Oct. 16-19	Oct. 24-31	Nov. 6-10	Nov. 15-17	Nov. 19-21
Heating Value (HHV, BTU/LB)	12,283	12,170	12,661	12,964	12,710
Ash	15.98	15.27	13.78	13.57	14.86
Moisture	3.35	4.08	2.74	2.15	2.16
Sulfur	2.03	2.03	2.14	2.20	1.79
Volatile	24.14	24.39	26.85	25.49	24.84
Fixed Carbon	56.53	56.26	56.63	58.79	53.18
Size Analysis (% Retained on Screen)	10/17	10/29	11/28	12/11	12/12
+ 1 in.	1.5	1.2	0.0	0.0	0.0
- 1 in. x + ¼ in.	64.5	69.2	60.6	50.6	59.2
- ¼ in. x + 12 U.S.S.	22.4	18.8	18.3	25.4	17.8
- 12 X + 20 U.S.S.	6.2	5.8	6.5	7.7	6.8
- 20 x + 30 U.S.S.	1.3	1.3	2.7	3.2	3.0
- 30 x + 40 U.S.S.	0.8	0.8	2.2	2.8	2.6
- 40 U.S.S.	3.3	2.9	9.3	10.3	10.6

TABLE IV - AS DELIVERED LIMESTONE SIZE ANALYSIS

Date	U.S.S. Sieve (% Passing)							Average Size Microns
	1/4"	6	8	10	16	20	30	
Nov. 9	100	99.3	71.0	58.2	16.4	2.3	0.3	1673
14	100	99.8	84.6	74.1	30.5	9.7	3.6	1275
20	100	99.8	83.6	71.2	22.5	5.0	1.9	1432
Dec. 17	100	99.9	91.9	81.3	29.8	4.3	1.2	1366
20	100	99.8	87.4	74.9	23.7	4.7	1.8	1409

Although full load operation of the steam generator has not been possible yet due to low load demand and auxiliary equipment constraints, full load design capacity of a single bed has been exceeded. With only bed A in service, load has ranged from 25,000 to 60,000 lb/hr. Although performance tests have not yet been carried out, it is apparent that the measured bed depth required to make full load is less than expected. This can be due to higher than anticipated fluidized bed heat transfer rates or a significant input of heat in the splash zone above the fluidized bed.

Prior to start-up, many concerns were expressed regarding possible fuel combustion in the freeboard above the fluidized bed. This problem has not occurred as evidenced by freeboard temperatures slightly lower than the operating bed temperature. On a few occasions when coal with a considerable percentage of fine particles has been used the freeboard temperatures have risen to approximately 1800F. These temperatures were quickly reduced by activation of the water spray system installed in the spreader feeders. With the addition of approximately 5% water by weight to the coal, the freeboard temperatures were reduced to below the operating bed temperatures during these excursions.

Air-Gas System

The forced draft and induced draft fan have performed as required, and with the exception of two ID fan bearing failures, have not caused any operating difficulties. The baghouse dust collector has done an excellent job of removing particulate from the flue gas resulting in a clear stack with very low opacity measurements. The stack opacity has generally ranged at approximately 10% which is well within the emissions requirement of 20% opacity. High pressure differential across the baghouse limited system capacity because of problems associated with the bag cleaning system. This problem was recently corrected by the baghouse supplier and no further problems are expected. Analysis of the bags in the baghouse has indicated that no acid attack has taken place. Acid attack of the bag materials is one of the primary factors that can limit the life of the bags. Because of the low SO_2 concentrations and high calcium content of the ash, limiting acid attack, extended bag life should be achieved.

Fuel System

The fuel receiving and handling system has functioned well. Only minor difficulties were experienced with the coal bin level detectors which were initially the paddle wheel type. They were replaced with

vibrating type level detectors which have worked satisfactorily.

The application of the spreader feeder for injecting fuel to the fluidized bed has been successful. This system has eliminated fuel feeding difficulties experienced on previous fluidized bed units which used pneumatic fuel feed systems. The spreader feeder application has resulted in more than a ten-fold reduction in the number of fuel feed points and has operated with high reliability.

Limestone System

No difficulties have been experienced with the limestone receiving, handling and feeding system.

Bed Material Removal System

As initially installed, the bed material removal system could not be turned down to a low enough removal rate to enable continuous operation. This was resolved by batch operation of the bed material coolers prior to modifying this equipment with a 4 to 1 gear reduction. Since the modification, this system has functioned well. The bed material coolers satisfactorily cool the 1600F material down to 100F before discharge to the pneumatic transport system.

Flyash System

The flyash reinjection system from the cinder trap and cyclone dust collector has been included to improve combustion efficiency. The cinder trap flyash reinjection system is designed for low collection efficiency to capture larger particles prior to their entering the boiler bank. This system is working satisfactorily and has maintained empty hoppers. Problems have been encountered with flyash reinjection from the cyclone dust collector. This system has been unable to maintain empty hoppers without excessive transport air in the eductor system. Due to the failure of this system to function as required, the combustion efficiency in the steam generator has been less than predicted. Steam generator tube erosion has been experienced on the rear wall of bed A through which the reinjection pipes penetrate. This has been attributed to a bed circulation pattern resulting from the high velocity in the flyash reinjection system and the orientation of the flyash reinjection discharge within the bed. Modification of this system is planned to improve operation.

The ash and bed material transport and storage system has worked satisfactorily with the exception of the air lock devices below the hoppers and bed material coolers. Difficulties with the drive linkages on these devices has resulted in back flow of transport air into the coolers and hoppers occasionally resulting in a forced shutdown. These linkage problems are being corrected by the equipment supplier.

Control System

Following some difficulties in the initial adjustment of the control system, the fluidized bed facility has operated on full automatic control. The control system is being optimized to maximize the rate of response to load changes. The control system receives input from an SO_2 and O_2 gas analysis system, which has had a low record of availability and has delayed the optimization of the automatic control system.

SYSTEM PERFORMANCE

Performance tests on the Georgetown University fluidized bed system have not been carried out to date. A system performance test at full capacity on the steam generator will be performed at the first opportunity. The system demand at Georgetown University only exceeds the 100,000 lb/hr capacity of the steam generator during the peak demand periods of winter and summer. Due to this year's warm winter season the peak demand exceeded boiler capacity for only a very short time which coincided with a scheduled outage. The next opportunity for full load operation is expected to be during August 1980. During the interim period, performance tests will be carried out at various part load operating points.

On December 5, 1979, test data was gathered at a load of 63,000 lb/hr with both beds in service. Since the fines reinjection system from the cyclone dust collector was not functioning properly during this operating period, the performance results calculated from this data indicate the lower expected combustion efficiency indicative of not using the flyash reinjection system. The operating data and performance conditions calculated from the December 5, 1979 operation are indicated on Table V. The boiler efficiency of 76.82% is considerably below the design efficiency of 83.51% since the fines reinjection system was not functioning properly and the unit was operating with high excess air. Stack emissions determined during the December 5, 1979 operation are indicated on Table II.

TABLE V - OPERATING CONDITIONS 12/5/79

	BED A	BED B	OVERALL
Steam Pressure (PSIA)	-	-	415
Steam Flow (LB/HR)	-	-	62,970
Blowdown Flow (LB/HR)	-	-	1,030
Air Flow (LB/HR)	51,670	43,170	94,840
Coal Flow (LB/HR)	3,434	2,861	6,295
Limestone Flow (LB/HR)	646	904	1,550
Feedwater Temperature (F)	-	-	240
Bed Temperature (F)	1,489	1,520	1,505
Freeboard Exit Temperature (F)	1,011	1,065	1,038
Stack Gas Temperature (F)	-	-	370
Bed Depth (IN)	20	20	20
Fluidizing Velocity (FT/SEC)	6.8	5.8	6.3
Excess Air (%)	67	69	68
Boiler Efficiency (%)	-	-	76.83
SO_2 Reduction (%)	-	-	86.56

SUMMARY

Operation of the Georgetown University fluidized bed facility has shown that fluidized bed combustion of high sulfur coal can be carried out in a highly populated urban area while meeting strict pollution emissions regulations. Although some operating difficulties have been experienced, these difficulties are typical start-up problems encountered during initial operation of a new facility and are not considered serious. Upon correction of difficulties with the fines reinjection system, we believe long-term reliable operation at good boiler efficiency will result.

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WOOD-COAL FIRED "SMALL" BOILER CASE STUDY

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Galaxy Carpet Corporation installed a coal and wood waste fired boiler approximately twelve months ago. Its first year net savings were $195,000.00 Total capital investment was paid off in 1.9 years. 20% investment tax credits were granted by the Federal Government. Galaxy Carpet Corporation has been sufficiently impressed with performance, both economically and technically, to place a follow-up order of $1,500,000.00 for a second solid fuel fired boiler system at its Dalton, Georgia Dye House operation.

The use of wood as a boiler fuel has increased dramatically in recent months due to the following:

1. Dollars per million BTUs delivered from wood are extremely attractive as opposed to the skyrocketing cost of oil and natural gas.

2. The SO_2 generated from wood is negligible, meaning reduced EPA problems and lack of corrosion in the boiler stack and breeching.

3. A much reduced ash content as compared to bituminous coal.

4. Reduced abrasion on material handling systems and lighter gauge material handling systems being possible, meaning reduced material handling costs as compared to coal.

5. The chemistry of wood is more uniform as opposed to the chemistry of coal or municipal waste and other waste-type fuels.

6. The combustion of wood is eligible for Federal Investment Tax Credits which make the return-on investment and payback periods extremely attractive to today's capital investment market.

7. Several states, including North Carolina, have enacted 15% State Tax Credits to further the use of wood fuel boilers.

Specific examples of the utilization of wood as a boiler fuel include Galaxy Carpet Mills, South Pittsburg, TN. Galaxy, at this particular location, spins yarn for later use in its carpet production facilities. A boiler with 300 HP output equaling 10,350 pounds per hour is installed at Galaxy. Management at Galaxy made the decision to proceed with the wood-coal fired boiler for the following reasons:

A. Gas may not be available at South Pittsburg for Galaxy. As a result, had a Scotch-Marine boiler been chosen, only fuel oil would have been available as a potential fuel.

B. The estimated payback period on the "turn-key" totally installed project was calculated to be 2.2 years with fuel oil, at that time, costing 42¢ per gallon. (#2 oil).

C. The return-on-investment was 30% plus, again based on 42¢ per gallon, #2 fuel oil.

D. Delivery of the "turn-key" boiler system, with all auxiliaries making commercial grade steam, was available in 25 weeks from purchase order.

E. All indications point to much higher boiler fuels and natural gas costs.

F. Although Galaxy is not a wood related industry, and does not have its own wood waste for boiler fuel, they are within 50 miles of major waste wood sources. Availability of wood on long term contract at a stable price was investigated and determined to be feasible. In addition, this particular boiler is certified and capable of firing on local bituminous coal, as well as natural gas and fuel oil.

G. EPA details were investigated and permits to construct and operate were determined to be no problem, based on the past testing of this particular equipment with similar fuels.

H. Galaxy management also determined that "turn-key", sole-source responsibility was the way they wanted to pursue this project, based on the fact that they had formerly had a bad experience with problem resolution after construction and start-up between equipment suppliers and installing contractors. For this reason, a sole-source engineering, equipment erection, material handling systems, installation, system start-up, EPA applications and permits issuance, owner and operator instruction and spare parts inventory team was ideal for their needs.

I. Efficiencies above 75% on a guaranteed basis were determined to be necessary by Galaxy management, based on the fact that Galaxy would be purchasing all of its waste wood fuel, as well as supplemental coal if needed. Efficiency guarantees of 80% on wood waste with less than 10% moisture content were given, as well as 78.5% on coal. These efficiencies were based on overall fuel to steam conversion and not simply combustion efficiency, which can be misleading.

This boiler is capable of firing on wood, coal, fuel oil, or gas. While firing on wood or coal, the boiler output is 250 HP or 8,625 lbs. per hour. The unit can fire on dry wood with a BTU content of 8,000 BTUs per pound, and it can also fire on green wood sized to 1" or less in any dimension. The stoker, which fires green or dry wood, can be fired simultaneously with the oil burner. This accomplishes two important features:

1. Quick savings in steam demand can be accommodated by the oil or gas power burner as the steam header pressure begins to drop. As you may be aware, solid fuels such as wood and coal do not track swinging steam loads well.

2. Should a conveyor jam up or other problems render the stoker temporarily inoperative, the oil or gas burner can immediately supply plant steam demands.

Relative to EPA permits to construct and operate, these have been issued with no problem. An EPA method 1 through 5 particulate emission test was not required due to substantial particulate emission test data available at the time of permit application. This project took approximately 25 weeks from initial purchase order and print approval to commercial start-up of steam. This particular job included all boiler equipment, freight, crane, rigging, necessary auxiliaries, fuel pumps, fuel oil tank, etc., totally "turn-key", exclusive of the boiler room, which was constructed of concrete block. The job was essentially "turn-key", in that Energy Systems, Inc. functioned as the "turn-key" boiler room contractor and the installed "turn-key" cost was $27.50 per lb. of steam capacity in early 1978 dollars. (We are currently seeing between 1 to 1.5% per month cost increases on equipment and materials).

The payback period for this particular job was 0.6 years with a return-on-investment in the low 85.0% category. Galaxy management felt this was an extremely attractive option due to the questionable availability of natural gas and the rapidly rising cost and potential availability problems of oil. Fuel is being purchased for this job from a local furniture factory on kiln-dried and delivered basis at $17 per ton. A ton contains approximately 16 million BTUs, resulting in a cost per million BTUs delivered, ready to burn of approximately $1.06. This compares very favorably to fuel oil at 80¢ per gallon with approximately 7.1 gallons being required to generate 1 MMBTUs equaling $5.71 per MMBTUs. This would assume an oil BTU content of approximately 140,000 BTUs per gallon.

($5.68 MMBTU gas/oil - $1.06 MMBTU coal/wood) = $4.62
(46.20 X 6,000 hr/yr = $277,200 gross savings/yr.)
$277,200 - $45,000 = $232,200 net saved/yr
$45,000 deduct for added electricity, labor, etc.
Therefore payback was:

$$\frac{\$275{,}000 \times 80\% \text{ (20\% tax credit)} - \$75{,}000 \text{ (gas/oil boiler)}}{\$232{,}200 \text{ (net saved)}}$$

Thus: .6 yr payback period.

The material handling details are extremely simple and direct, basically involving one 14" U-trough screw for delivery of the waste wood products from the bunker area to the boiler hopper. This screw is actuated automatically from the hopper by a bin level switch. The wood bunker is designed for self unloading trucks such as the BoCat or Peerless type live bottom trucks. This type truck simply backs into the fuel storage area, which has a covered roof for prevention of direct rain onto the piles. After unloading by the live bottom truck, the material is moved as required on the fuel bunker floor to a secondary screw which moves material on demand to the primary 14" U trough screw leading to the boiler hopper. An infinite variety of configurations can, of course, be utilized depending on the particular unloading, storage volume, and fuel size requirements. If desired, a complete wood processing yard can be installed, which would allow the customer to buy slab end cuts, and other large size waste wood pieces 8 to 10 feet long. This would then be hogged, sized, screened, and suitably processed for delivery to the boiler. Obviously this increases the capital investment and labor input substantially. Our recommendation on small boilers (under 50,000 lbs/hr) is to buy purchased, hogged fuel, delivered by self unloading trucks. We have many waste wood brokers calling us to offer this service and would be happy to share this information with you. Ultimately, it appears to us that waste wood and brokering will become as organized and active as coal brokering is currently.

Assistance on the availability of wood waste was offered by the local states (Tennessee, Georgia and Alabama) Department of Forestry. These people have wood utilization divisions which specialize in such uses as boiler fuel for waste wood. In addition,

the Tennessee Valley Authority at Norris, Tennessee has a substantial data bank of wood availability as well as technical information from the foresters. TVA is also researching pyrolysis and gasification units for utilization of wood waste. One very interesting research development during our survey for wood was the recent enactment by the North Carolina State authorities of a 15% investment tax credit on the state level above and beyond the Federal tax credits available for the utilization of wood in that state. Some help in the form of technical information on wood availability may be offered by various State Departments of Energy. However, we found these sources to be limited, and in some cases, very politically oriented.

An interesting fact which makes wood a good fuel is that its chemistry is more uniform than that of coal. Coal typically varies from the very hard anthracite coals to the very soft, very moist lignite fuels of the Southwest. As a result, critical chemical and physical properties of coal, such as the ash fusion temperatures, swelling tendencies and percent sulphur vary from one location to the next and from one truckload to the next. Wood appears to be a predictable fuel from the standpoint of its ash fusion point, percent sulphur, swelling characteristics during initial combustion, and the lack of clinkering (or fusion of large blocks of ash) characteristic of Southeastern coals. This should encourage the use of wood.

Relative to preventative maintenance and general maintenance, on this type boiler, obviously conveyors will have standard maintenance requirements such as V belt replacement, oiling, periodic replacement of wear plates, etc. However, this is very similar to the type of maintenance that would be observed in an agricultural silo operation utilizing U trough screws, due, again, to the low abrasive characteristics and general lack of tramp iron, rocks and dirt in the supplied wood as opposed to coal which usually does have all of these foreign objects in them. Relative to the boiler, three additional motors for underfire air, overfire air, and hydraulic pressurization of the stoker ram are involved. These are industry standard motors and components with industry type, standard maintenance requirements. All spare components are "off the shelf" industry standard. We have not observed maintenance requirements at Galaxy to date.

We have three years operational experience at Kimball International, the large piano and organ manufacturing operation, with three of these boilers continuously burning dry furniture wood waste. These units require very low preventative maintenance requirements, and the total budget allocated to this amounts to approximately $5,000 per year for all three units. A complete spare parts inventory is recommended at the start-up phase of the job for several reasons:

1. Management seems more willing at that stage of the project to recognize spare parts requirements and their associated cost, and they allocate funds as part of the overall project cost.

2. Spare parts may be needed at any time. Boiler operations are normally critical to plant output. As a result, spare parts and their ability to minimize down-time are very important.

A second case study relative to wood/coal utilization and steam boilers, involves several recent jobs in which old boilers were retrofitted with modern underfed ram stokers to fire various plant wastes, including sander dust, sawdust, and polisher dust, with a back-up fuel of coal. This situation involved some interesting challenges for the following reasons:

1. The existing boilers with their original grate burning system were in violation of EPA particulate emissions and opacity requirements.

2. The burning of superfines (or finely ground polisher dust) can be a potential explosion hazard as this material gets in suspension in the combustion chamber and suddenly ignites.

3. The existing boilers were in a deteriorated condition with respect to their refractory and existing brick. In this case, the problem became one of retrofitting modern underfed stokers that would capture the superfine material and burn it before it had the opportunity to go into suspension where detonation potentials exist.

4. The existing draft at the project initiation was very low due to leaking rear doors, holes between the drum and refractory, breeching losses through holes, as well as the front firing doors and ash doors. Without sufficient draft, the underfire and overfire air fans pressurized the combustion chamber resulting in smoke exiting the front doors of the boiler, filling the boiler room with products of combustion. In addition, a special log chain

bridge breaker was installed in the hopper to eliminate the packing of the superfines and the subsequent bridging at the screw conveyor inlet which stops all fuel flow to the boiler.

Retrofit of old boilers which were originally designed to fire coal is a practical consideration. The major points to keep in mind include:

1. The present condition of the equipment may not warrant the investment in stokers. This might include deterioration of the drum and tubes by oxygen pitting, structural steel deterioration on the HRT type boilers, inadequacy of the boiler size--that is, the boiler once retrofitted may not meet your near-term steam demands if your company is adding additional steam-using equipment.

2. Efficiencies on the older boilers will never be as high as the more modern, recently installed equipment designed specifically for high efficiencies.

3. EPA impact must be investigated on each individual boiler installation. Forecasting the particulate loading in the stack gas is an exacting science requiring substantial expertise. However, retrofitting existing boilers which are in good condition can save over 50% of the costs associated with installation of new solid fuel boilers.

Final comments concerning the utilization of wood for steam energy include:

A. The importance of obtaining a long term contract as soon as possible in the project life to secure wood waste or processed wood fuel on a negotiated cost per ton or cost per BTU basis, plus a cost of living escalator which will assure that your costs do not rise uncontrollably. TVA and the large fuel purchasers of the nation generally buy their fuel on a dollar per MMBTU basis. This assures against delivery of excess real estate, water and other contaminants in the fuel. However, it also requires a sampling program by an independent laboratory to protect both the supplier and the customer's interest. This may not be feasible on small boiler operations. However, at this point in time, contracts can be negotiated for waste at substantially under $1.50 per million BTUs on a delivered basis. We feel that the cost of wood for energy will rise at least as quickly as the cost of living--probably several points per year higher. However, since substantial capital investment by corporations does have considerable lag time, we see no massive demand for the residue wood already available on the market coming sooner than the next 18 to 24 months. So an opportunity still exists in the next year to negotiate some very attractive fuel contracts.

B. To a non-wood industry, a boiler which can also burn coal becomes very important since captive fuel from your own operation may not be available or may not be adequate to supply your fueling needs. Here again, the concept of fueling flexibility and high efficiency will be paramount in the coming years.

Wood has every indication of becoming an important contributor to the energy supply of this nation, particularly in the 10,000 to 100,000 pound boiler market, because of its inherent cleanliness, drastically reduced ash with respect to coal, lack of any substantial sulfur, and its renewable capacities. Recent data from universities indicate that under optimum conditions, wood energy plantations could produce as much as 20 tons per acre per year of energy wood. This, essentially, is a concentrated form of solar energy which has an outstanding future. Ten years from today, wood waste and wood processed fuel will be serving a large part of the 10,000 to 100,000 pound per hour processed boiler fuel market. Even today, the economics of wood utilization for energy are extremely attractive for any boiler operation running more than 4,000 hours per year. In the near future, people will not refer to abandoned sawdust piles and other wood scrap areas as waste, but as energy stockpile.

THE ANALYSIS AND DEVELOPMENT OF LARGE INDUSTRIAL STEAM SYSTEMS

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ABSTRACT

Chemicals, petroleum, pulp and paper, and many other industries depend heavily on extensive complex steam systems for thermal and mechanical energy delivery. Steam's versatility and desirable characteristics as both a heat transfer medium and a working fluid has fostered and perpetuated this dependency throughout industrial history. Many large process operations, however, have not developed their steam systems to keep pace with rapidly changing energy economics. As a result, the use of steam on industrial plants seldom approaches the optimum levels of first or second law efficiency. At each of many industrial complexes today, tens of millions of energy dollars per year are literally wasted.

This paper describes some case histories comparing actual and optimum steam system configurations, and operational concepts. Highly effective steam system analytical techniques developed and used by the author are discussed. These include "energy level" mass balancing; the "three-branch" thermodynamic system; and powerful sophisticated ditigal computer steam system models. These latter are really "working models" on which development options can be tried and actively evaluated for economic and technical feasibility.

The principal of steam as a plant-wide integrating energy system is explained and demonstrated with examples. These show how a properly structured and effectively operated steam system can increase operational flexibility and facilitate the practical implementation of many energy conservation opportunities in process and plant service areas.

On nearly all industrial plants, and particularly the hydrocarbon and process industries, steam is the single most dominant energy system. For these industries, steam constitutes the delivery means for well over half of the total energy input. Why is this? -- It is because of steam's nearly ideal thermodynamic properties, its versatility, its safety, and the universality and low cost of the basic fluid.

Other more subjective reasons for the prevalence of steam on industrial plants are the fact that it has been around a long time; we are familiar with it and know a lot about it. The history of our highly industrialized economy parallels the history of steam power.

In the process industries, steam is used as a heat transfer medium to convey heat from burning fuel in a boiler furnace to steam heated process equipment such as reboilers, reactors, dryers, evaporators, and many others. Steam's second important function on industrial plants is as a working fluid. It is expanded from a high pressure to a lower pressure through steam turbines or steam engines to produce shaft work, sometimes referred to as prime energy. Prime energy is the most costly as well as the most valuable form of energy. Further, steam finds use in the petroleum and petrochemical industries as an actual ingredient in some important process operations. In still other cases it is used directly in the process as a diluent or moderator to control reaction rates or limit process temperatures.

Another very important use of steam is the collection and distribution of waste heat. Steam is a true integrating energy system. By this we mean that, on a diversified chemical complex, steam generated by any operation can be used conveniently by virtually any other operation. The use of waste heat steam boilers permits the recovery of maximum

prime energy potential as well as heat. For example, a waste heat boiler recovering heat from the exhaust of a combustion gas turbine can produce steam that is then expanded through a steam turbine adding to the production of prime energy. The exhaust steam from the steam turbine can then be used for necessary process heat requirements.

A lot of good things can be said about the use of steam on process industrial plants. Unfortunately, there are a lot of bad things, as well. The petroleum processing and petrochemical technology that we are using today was, unfortunately, developed during an era of almost unbelievably low energy costs. The steam systems supporting these process operations still, to a large extent, reflect thinking that was right 10 or 15 years ago but is now disastrously wrong.

Today, with remarkably few exceptions, industrial steam systems are literally wasting vast amounts of energy. The consultants in our firm have worked with many process plants. Invariably, steam system savings ranging from 10 percent to 40 percent of total plant energy expenditures can be found. For some plants it has even been possible to reduce energy expenditures to as little as one-third of the previous level through optimum development of the steam system.

Steam economy depends on the steam system design and the understanding by plant personnel of how the system should be most effectively operated and maintained.

There are two basic design concepts that have been applied to process energy steam systems. I will call these the "Power Base" and the "Thermal Base." Before the electric utilities were as highly developed as they are today, it was common for oil refineries and large chemical operations to generate their own electricity using steam turbines. In addition, steam drives were applied directly to machinery items requiring large blocks of horsepower. Smaller pumps and other items of mechanical equipment were also frequently driven by mechanical drive steam turbines or steam engines because of the higher reliability that then was assumed to result from avoiding dependence on the utility electric power supply.

With the power base system design, (Slide 1) exhaust steam or extraction steam would be used, if convenient, for process heat requirements. If there were not sufficient convenient thermal needs, the larger turbo generators and major compressor drives would be subatmospheric condensing machines. The surplus exhaust from smaller machines would simply be vented to atmosphere. I am familiar with one very large chemical complex that, until very recently, was venting as much as 400,000 pounds per hour of steam to the atmosphere continuously. Many other plants vent lesser but still substantial quantities of steam. Even today, a surplus of low pressure steam is a chronic malady of a large portion of the process industries. (1)

The thermal base steam system design is characterized by the process plant that produces saturated steam with fuel-fired boilers in the 100 to 175 psig range and produces only enough steam to meet process heat requirements. The boiler feed pumps and possibly the boiler fans might be steam turbine driven but this is the extent of steam use as a working fluid.

The thermal based design (Slide 2) does not exploit the full potential for producing low cost shaft work (co-generation potential) but the overall dollar energy losses are usually much less severe than for the power based design. (2)

The best approach is a judicious combination of the two concepts. This would be relatively easy for a process industrial plant being designed now but for existing plants, a very thorough and structured analysis must be performed leading to a comprehensive coordinated development plan. The end result is no steam produced using fuel-fired boilers beyond the valid heat requirements of the process; all steam used at the lowest practical pressure level; all steam produced at the highest practical pressure and temperature level; and all steam needed by the process expanded through efficient

work-producing devices.

What is wrong with our industrial steam systems? Why are they so inefficient? Why is there so much potential for improvement? Certainly, our industrial expertise must include a knowledge of basic steam thermodynamics. The problem is many fold, I have already mentioned the disastrous affect of unrealistically low energy costs for the petroleum and petrochemical industries during the past two decades. Add to this, the topsy-turvy growth of process industry plant sites with little or no broad-range steam system planning. The objective was to get there with the capacity to make products at the lowest possible capital investment. On a single industrial complex, some process units would be "Thermal Based" (with respect to steam) and another adjacent unit, "Power Based."

I participated in a comprehensive energy study at a large multiproduct chemical complex on the Gulf Coast not too many years ago. One unit required 30,000 horsepower for two large compressors, and was providing this power by steam turbines receiving steam at 600 psig and exhausting the steam at 40 psig. The exhaust level process heat requirements required approximately one-third of the exhaust steam and the balance was vented through an expensive vent-silencer device directly to atmosphere. A distillation process producing a completely unrelated product, right next door, was pressure reducing steam through a let-down valve and desuperheater station from the 600 psig level to 30 psig for reboilers and process heaters. Now remember, this was the same company but two different product divisions (two different profit centers) who didn't talk to each other about energy and as a result, cost their company several million dollars a year. Now that was a few years ago. This sort of thing now would probably cost three times as much.

Large complex steam systems serving a variety of product operations must be considered as integrated systems; analyzed as a single entity; and developed to secure the maximum economic benefit for the entire complex.

Joint venture co-generation projects have been considered for groups of plants in one area. This offers excellent real energy saving potential. We promote and encourage this as much as possible. Superimposing a co-generation steam source, however, on an existing uneconomical steam system does not solve problems -- it intensifies them. The first step should be a steam system analysis leading to a practical development plan to be implemented prior to start-up of the co-generation facility.

Let's talk a bit about analytical techniques. I think we have defined the systems concept: when we mentioned industrial steam, don't think about the boiler plant. Think also about the site distribution system, steam turbines, process thermal steam requirements, and the condensate return system. The steam balance is one of the most important analytical techniques used in the successful analysis and development of existing steam systems. The first step is usually the mass balance. The best presentation is the "energy level" mass balance. This slide (Slide 3) is a typical schematic energy level (3) mass balance. Note that the various pressure levels used in the plant are shown as headers represented by horizontal lines with the highest pressure headers at the top and progressively lower pressures toward the bottom of the sheet. Energy flow toward lower levels is depicted by vertical lines serving the various process users or steam turbines. A very extensive and complex system can be represented by a continuous strip defining all of the steam uses and steam expansions.

The energy level mass balance can also be portrayed in tabular form as shown in this table (Slide 4). (4) Note that for both the schematic and the tabular mass balance that the steam flows entering and leaving each pressure level form an accounting balance.

The simple mass balance is extremely useful and forms a basis for virtually all steam system analysis work. A pound of steam, however, does not always represent the same amount of energy. High pressure superheated steam might have an enthalpy of more than 1400 Btu per pound. Wet exhaust steam, on the otherhand,

may contain as little as 800 or 900 Btu per pound. This is where the mass and energy balance comes in. For the smaller and less complex systems, mass and energy balances might be required only at the boiler area. In any case, we should learn to think of steam as a means of conveying energy -- that is conveying Btu's -- to process heat requirements. Pounds per hour of steam is meaningless without a full appreciation of the heat content of each pound and the various things that cause this heat content to change.

Here is a mass and energy balance technique that is very useful for analyzing specific steam system components (Slide 5). The "three-branch thermo dynamic system" covers such steam system components as the deaerating (or contact) feedwater heater; the flash recovery tank; and the desuperheater. The routine shown is for one of the popular programmable hand-held calculators and is easily adapted to similar equipment. Essentially, it solves two simultaneous equations in two unknowns.

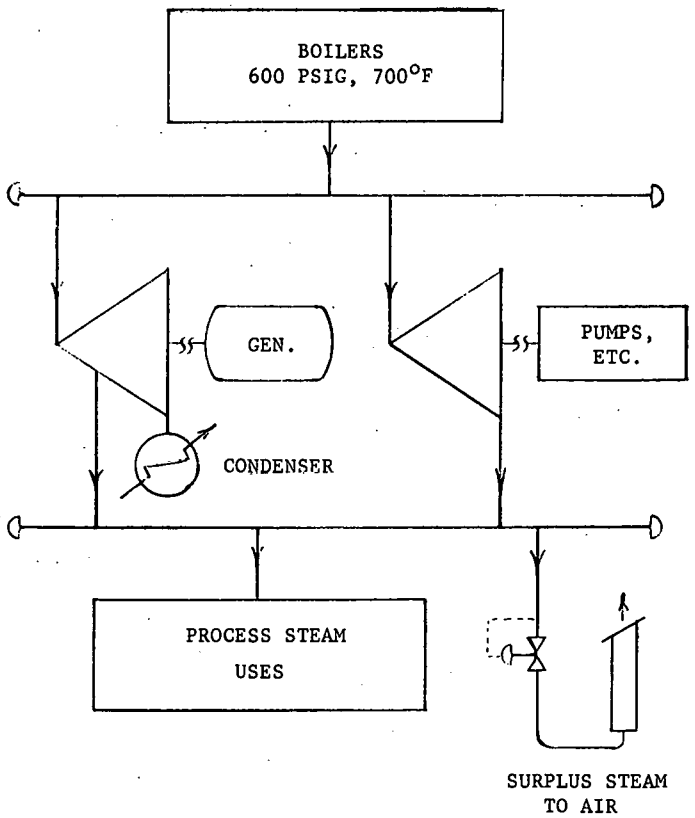
The next diagram (Slide 6) is part of the flow diagram used in a very sophisticated mass and energy balancing technique applicable to very complex and extensive industrial steam systems. This is a digital computer modeling technique developed by the Syntha Corporation and known as Syntha III. The technique is an integral part of a comprehensive steam system analysis program developed by our firm. It becomes a reliable working model of the steam system with which developmental options can be pretested for both economic and technical feasibility.

The basic objective of all steam system development work is to minimize overall cost while still achieving all of the necessary results. What boiler pressures should be used? What intermediate pressures are needed? What is the lowest steam pressure that can be used?

I recently participated in the study of a textile operation. The plant had two turbo generators exhausting to subatmospheric condensers. Now we know, as many of you also know, that subatmospheric condensing turbo generators are not economically feasible on most industrial plants. If you do have them, however, you should operate at the best vacuum that can practically be achieved so as to maximize the power developed from each pound of steam going to the condenser. The machines in question, however, were operating at about 11" Hg. vacuum. Now here was a double energy inditement. First of all, they were using subatmospheric condensing equipment and, to make matters worse, the vacuum was lousy. But wait a minute, this operation required a large quantity of wash water at approximately 160°F. The wash water was heated by using fresh water as the cooling medium for the turbo generator condensers. The turbo generators were not really subatmospheric (5)
condensing machines. They were back-pressure units and all the heat in the turbine exhaust was being used to meet a valid process thermal requirement at the lowest practical level.

This illustrates the basic second law concepts that must always be applied in the analysis and development of industrial steam systems. First of all, steam should always be produced at the highest (6)
practical temperature and pressure level. The steam should then be expanded through efficient work producing devices to the lowest practical process use level. This is the ultimate objective of effective industrial steam system analysis and development.

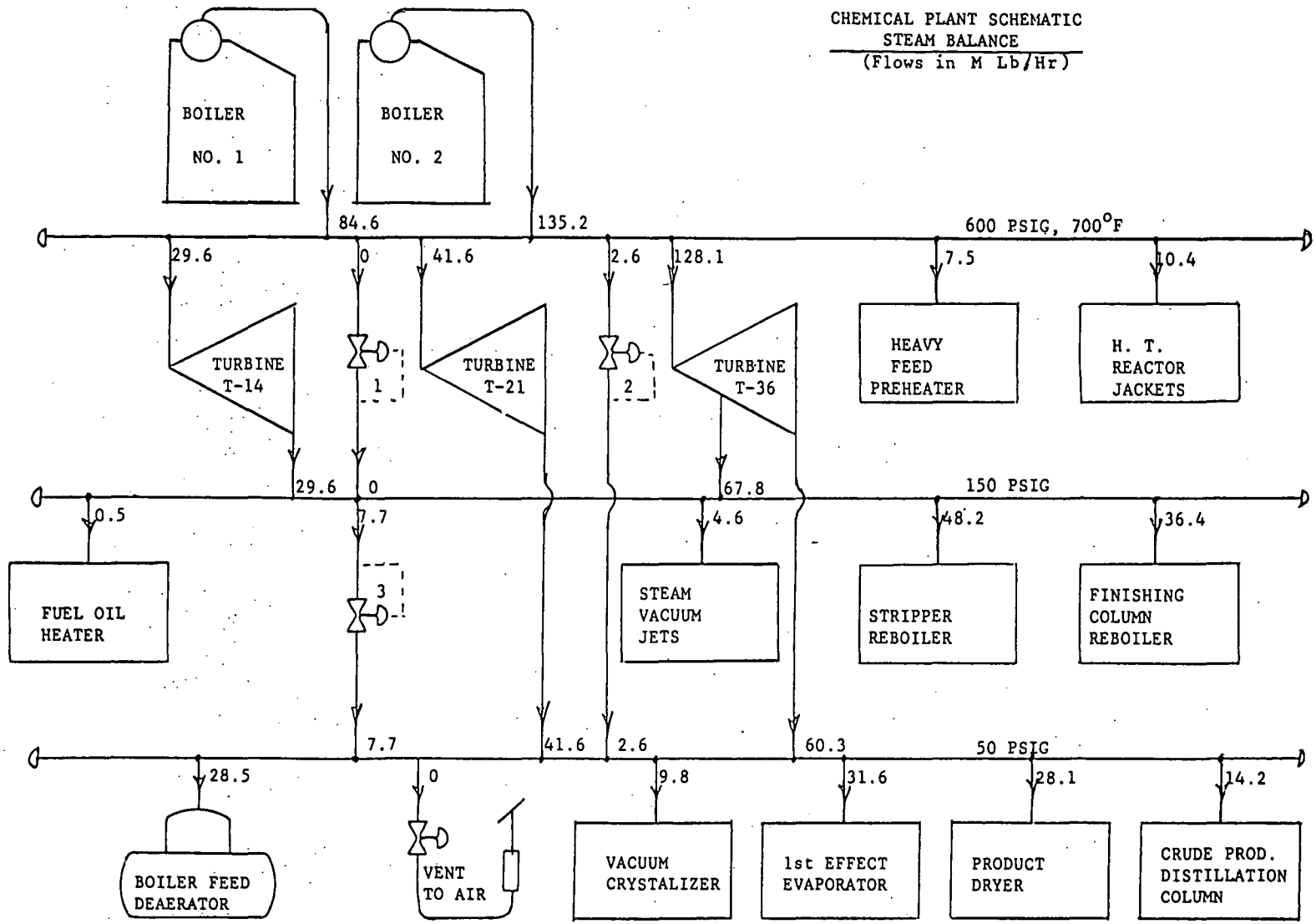
SLIDE NO. 1



POWER BASED

SLIDE NO. 3

CHEMICAL PLANT SCHEMATIC
STEAM BALANCE
(Flows in M Lb/Hr)



CHEMICAL PLANT TABULAR STEAM BALANCE
(Flows in M Lb/Hr

	600 PSIG, 700°		150 PSIG		50 PSIG	
	Supply	Use	Supply	Use	Supply	Use
Boiler No. 1	84.6					
Boiler No. 2	135.2					
Turbine T-14		29.6	29.6			
Turbine T-21		41.6			41.6	
Turbine T-36		128.1	67.8		60.3	
Pressure Reducing Valve No. 1		0	0			
Pressure Reducing Valve No. 2		2.6			2.6	
Pressure Reducing Valve No. 3				7.7	7.7	
Heavy Feed Preheater		7.5				
H.T. Reactor Jackets		10.4				
Fuel Oil Heater				0.5		
Steam Vacuum Jets				4.6		
Stripper Reboiler				48.2		
Finishing Column Reboiler				36.4		
Boiler Feed Deaerator						28.5
Vent to Air						0
Vacuum Crystalizer						9.8
1st Effect Evaporator						31.6
Product Dryer						28.1
Crude Product Distillation Column						14.2
Totals	219.8	219.8	97.4	97.4	112.2	112.2

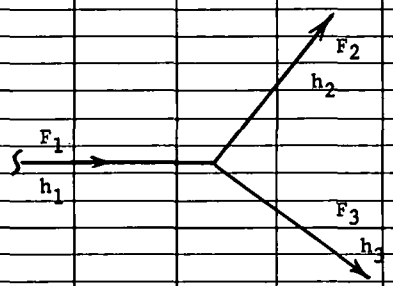
SLIDE NO. 5

HP55 Program Form

Title 3-BRANCH THERMODYNAMIC SYSTEM Page 1 of 1

Press BST in RUN mode, switch to PRGM mode. Then key in the program.

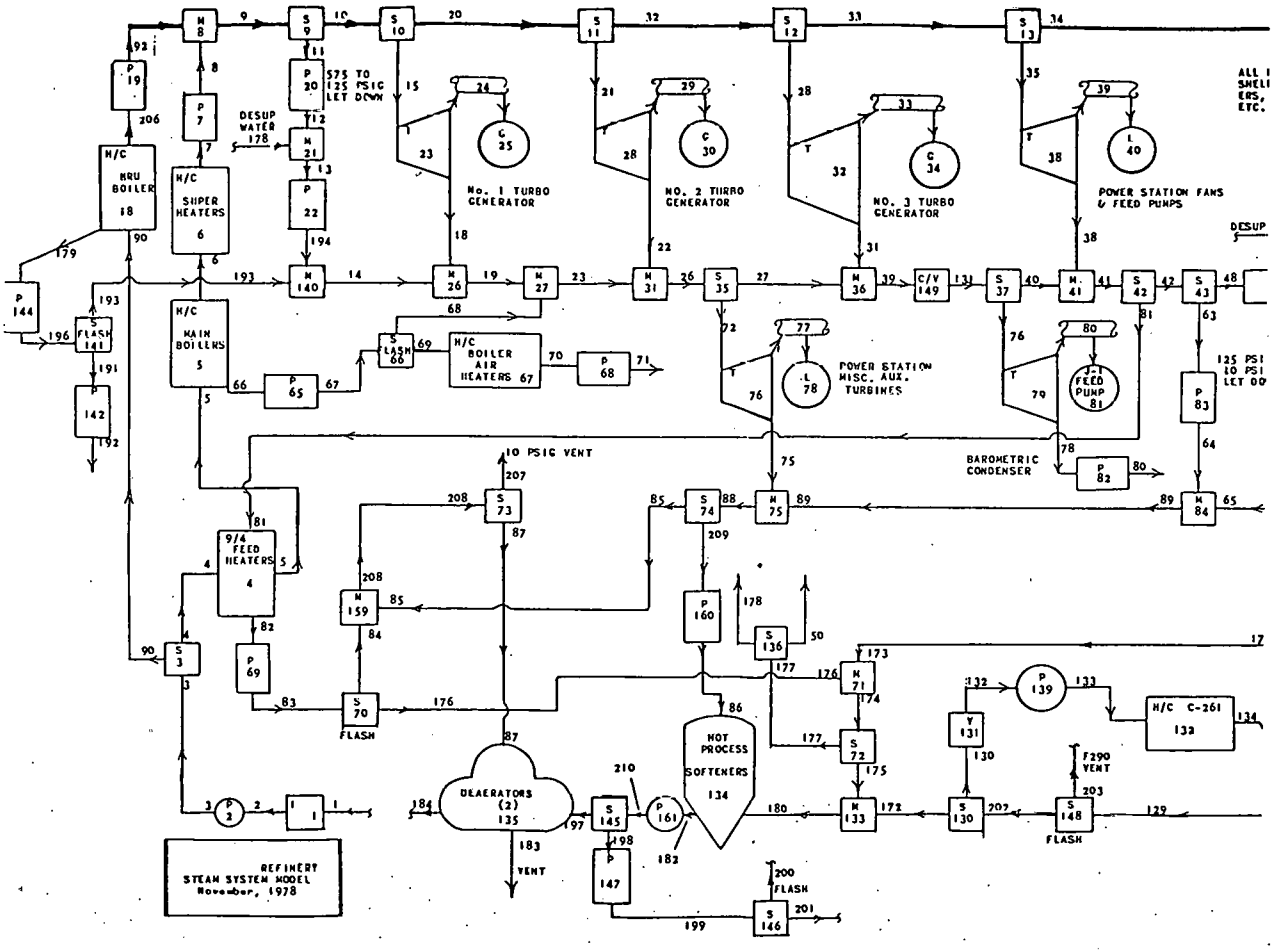
DISPLAY LINE	DISPLAY CODE	KEY ENTRY	X	Y	Z	T	COMMENTS
00.				KEY IN F, THEN	HIT R/S		
01.		STO					
02.		0					
03.		RCL					
04.		3					
05.		RCL					
06.		1					
07.		-					
08.		X					
09.		RCL					
10.		3					
11.		RCL					
12.		2					
13.		-					
14.		÷					
15.		R/S	DISPLAYS VALUE OF F_2,		THEN HIT	R/S	
16.		CHS					
17.		RCL					
18.		0					
19.		+					
20.		GTO-00	DISPLAYS VALUE OF F_3				
21.							
22.							
23.							
24.							
25.							
26.							
27.							
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33.							
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35.							
36.							
37.							
38.		MUST KNOW ALL THREE ENTHALPIES AND ANY ONE FLUW.					
39.		FLOWS IN DIRECTION OF ABOVE ARROWS ARE +, IN OPPOSITE					
40.		DIRECTION -. TO ENTER NEGATIVE FLOW KEY FLOW THEN CHS					
41.		BEFORE HITTING R/S.					
42.							
43.		DIAGRAM REPRESENTS FLASH RECOVERY TANK. PROGRAM					
44.		ALSO USED FOR: DEAERATING HEATER OR ANY OPEN HEATER					
45.		STEAM DESUPERHEATER.					
46.							
47.		ANY FLOW UNITS MAY BE USED AND RESULTS WILL BE IN					
48.		SAME UNITS.					
49.							



REGISTERS	
R 0	
R 1	h_1 BTU/LB
R 2	h_2 BTU/LB
R 3	h_3 BTU/LB
R 4	
R 5	
R 6	
R 7	
R 8	
R 9	
R.0	
R.1	
R.2	
R.3	
R.4	
R.5	
R.6	
R.7	
R.8	
R.9	

HEWLETT PACKARD

9320-2940


HRU BOILER 18
SUPER HEATERS 6
MAIN BOILERS 5
9/4 FEED HEATERS 4
BOILER AIR HEATERS 67
No. 1 TURBO GENERATOR
NO. 2 TURBO GENERATOR
NO. 3 TURBO GENERATOR
POWER STATION FANS & FEED PUMPS
POWER STATION MISC. AUX. TURBINES
BAROMETRIC CONDENSER
DESUP WATER 178
DESUP
125 PSI TO 10 PSI LET DOWN
10 PSIG VENT
DEAERATORS (2) 135
HOT PROCESS SOFTENERS 134
FLASH
VENT
F290 VENT
REFINERY STEAM SYSTEM MODEL November, 1978

CO-GENERATION AT A PRACTICAL PLANT LEVEL

John Feuell

Coppus Engineering Corporation
Worcester, Massachusetts

The Steam Turbine

A basic description of how a steam turbine converts available heat into mechanical energy to define the formulae used for the cost comparisons in the subsequent examples.

Co-Generation

Comparison between condensing cycle and back pressure turbine exhausting to useful process, identifies potential energy savings.

Process Power Recovery

Replacing pressure reducing valve with steam turbine produces mechanical or electrical energy in conjunction with process heat.

Steam vs. Electric Motor

Comparison of electric motor operating cost with steam turbines to show that cost-savings depend on application.

Waste Heat Recovery

The addition of a steam turbine can justify waste heat projects that were previously not feasible on an economic basis.

INTRODUCTION

The relevance of steam turbines to energy conservation is not because of any major technical advances in design or construction but because of the need to review their application in the face of rising fuel costs and rising electricity costs.

The electricity cost is the most dramatic factor because prior to the early 1970's the cost of electricity had traditionally decreased as a result of advances in size and technology of large utility power plants.

This meant that in the past a potential "in-house" power plant could be faced with a diminishing return if fuel cost increased, while purchased electricity cost decreased.

This no longer holds true, in fact, the utilities are faced with massive investment for new plants and the indication is that electricity charges will increase at a rate at least equal to fuel cost.

THE STEAM TURBINE

The steam turbine is a machine which extracts heat from steam and converts it into mechanical work by expanding steam from high pressure to low pressure.

This is achieved by accelerating steam through a set of fixed nozzles and directing the high velocity jet through moving blades mounted on a rotor. The change in momentum of the steam through the blades produces torque at the rotor shaft.



COPPUS BACK PRESSURE TURBINE

Horsepower is a function of torque, which is a function of the steam velocity, which is a function of the available heat drop.

The available heat drop is shown on a mollier diagram, fig (1). Available energy which can be converted into work is shown by the isentropic expansion line $h_1 - h_2$.

The actual power which can be produced by a steam turbine from this heat drop is given by the following equation:

$$HP = \frac{M \times E_t \times (h_1 - h_2)}{2545} \qquad - - (1)$$

The steam turbine in common with any heat engine requires a source of heat and a heat sink, which is represented by the line $h_1 - h_2$. The turbine cannot produce more work than this available heat drop and in practice the turbine can only produce an amount of work less than this, equivalent to a heat drop of $h_1 - h_3$. This is due to various physical losses, which grouped together are defined as the efficiency of the turbine E_t, where:

$$E_t = \frac{h_1 - h_3}{h_1 - h_2} \qquad - - (2)$$

This function, h_3, the heat remaining in the turbine exhaust steam, is one of the keys to identifying energy saving potential using steam turbines.

From equation (2):

$$h_3 = h_1 - E_t \times (h_1 - h_2) \qquad - - (3)$$

Whether or not this heat h_3 is subsequently used can dramatically affect the overall operating cost of the plant.

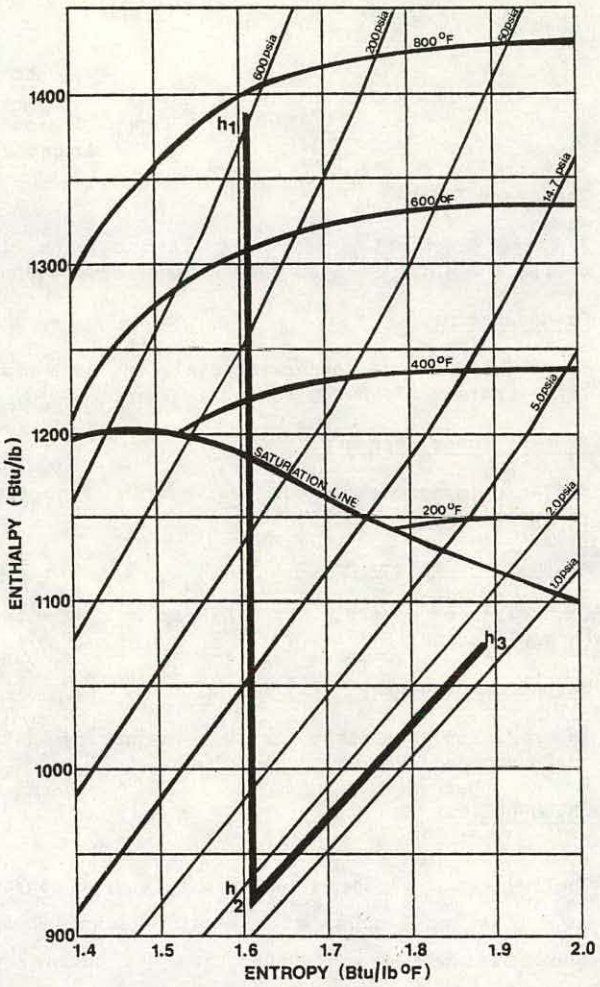


FIG.1 MOLLIER CHART

There are two basic modes of operation of a steam turbine which affect this:

The condensing steam turbine, which is primarily used in power plants to produce electricity.

The back pressure steam turbine which is commonly used as a mechanical drive in refinery, petrochemical, and powerhouse applications because of its reliability, independence from electric power, and as a cheap source of mechanical energy.

This application of the back pressure turbine exhausting to a useful process or heating load is a simple form of co-generation.

CO-GENERATION

Co-generation is the complementary production of electricity or mechanical energy in conjunction with the production of heat for use in a process (topping cycle) or from the waste heat produced from a process (bottoming cycle).

The potential for energy saving using this concept can be shown by comparing the heat balance of a simple condensing cycle with that of a back pressure turbine.

1. Simple condensing cycle

In the condensing cycle shown in fig 2, 25,000 lbs./hr. of steam is produced at 600 psig, 750°F, and expanded through a steam turbine exhausting to a condenser with a vacuum of 3 inches HgA.

A. The HP which can be produced by a small multi-stage turbine with overall efficiency of 65% is given by equation (1):

$$HP = \frac{25{,}000 \times .65 \times (1379 - 918)}{2545}$$

$$= 2944$$

B. The turbine exhaust enthalpy is given by equation (3):

$$h_3 = 1379 - .65 \times (1379 - 918)$$

$$= 1079.4$$

C. Throughout this paper the fuel cost $/mm BTU will be based on using No. 6 fuel oil with heating value of 149,000 BTU/gal. and costing $0.50/gal., which gives:

$$\text{Fuel Cost} = \frac{.5 \times 10^6}{149{,}000}$$

$$= \$3.356/\text{mm BTU}$$

D. In this example with boiler efficiency of 85% and 90% condensate return, the cost of producing steam is given by:

$$\$/\text{mlb.} = \frac{(h_1 - h_6) \times \$/\text{mm BTU}}{E_b \times 1000} \qquad - - (4)$$

$$= \frac{(1379 - 76.5) \times 3.356}{.85 \times 1000}$$

$$= \$5.14/\text{mlb.}$$

E. The cost per HP is given by:

$$\$/HP = \frac{M \times \$/\text{mlb.}}{HP \times 1{,}000} \qquad - - (5)$$

$$= \frac{25{,}000 \times 5.14}{2944 \times 1{,}000}$$

$$= \$.044/HP$$

F. The heat supplied to the boiler is given by:

$$Q_B = \frac{M \times (h_1 - H_6)}{E_b} \qquad - - (6)$$

The heat removed from the condenser and lost to the atmosphere, Q_A, is given by:

$$Q_A = M \times (h_3 - h_4) \qquad - - (7)$$

Note the percentage of energy lost to the atmosphere.

$$= \frac{Q_A \times 100}{Q_B}$$

$$= \frac{M \times (h_3 - h_4) \times E_b \times 100}{M \times (h_1 - h_2)}$$

$$= \frac{(1.079.4 - 83) \times .85 \times 100}{(1379 - 76.5)}$$

$$= 65\%$$

It is this massive loss of energy which the co-generation cycle attempts to recover.

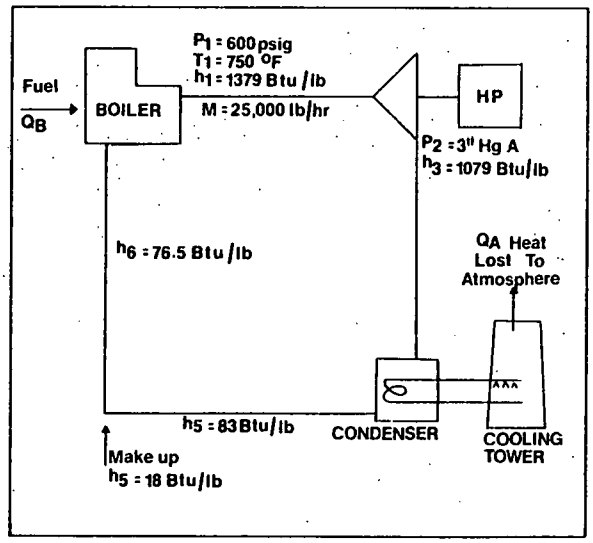


FIG. 2 SIMPLE CONDENSING CYCLE

2. Process Steam with Back Pressure Turbine

In this cycle, shown in fig 3, 25,000 lbs./hr. of steam is produced at 600 psig, 750°F, and then expanded through a back pressure turbine exhausting steam at 80 psig to a useful process to provide heat Q_p.

A. The HP which can be produced by a single-stage back pressure turbine with overall efficiency of 50% is given by equation (1):

$$HP = \frac{25{,}000 \times .5 \times (1379 - 1187)}{2545}$$

$$= 943$$

B. Turbine exhaust enthalpy from equation (3):

$$h_3 = 1379 - .5 \times (1379 - 1187)$$

$$= 1283$$

C. With boiler efficiency of 85% and 80% condensate return, the cost of producing steam is given by equation (4):

$$\text{Steam Cost} = \frac{(1379 - 148) \times 3.356}{.85 \times 1000}$$

$$= \$4.86/\text{mlb.}$$

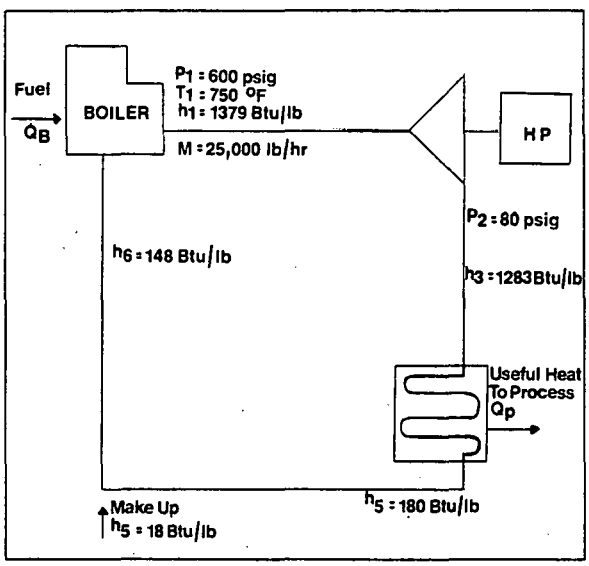


FIG.3 Process steam with back pressure turbine

D. When the steam cycle has been designed to include a back pressure turbine, the cost of producing shaft HP is equal to the cost of the heat which is converted to HP:

$$Q_{hp} = M \times (h_1 - h_3) \qquad - - (8)$$

The cost per HP is given by:

$$\text{Cost/HP} = \frac{M \times (h_1 - h_3) \times \$/\text{mm BTU}}{HP \times E_b \times 10^6}$$

$$= \frac{2545 \times \$/\text{mm BTU}}{E_b \times 10^6} \qquad - - (9)$$

Relating equation (9) to steam cost in $/mlb:

$$\text{Cost/HP} = \frac{2545 \times \$/\text{mlb.}}{(h_1 - h_6) \times 1000} \qquad - - (10)$$

In this example:

$$\text{Cost/HP} = \frac{2545 \times 4.86}{(1379 - 148) \times 1000}$$

$$= \$.01/\text{HP}$$

This clearly compares very favorably with the simple condensing cycle rate of $.044/HP.

The main drawback is that less power is produced from the same quantity of steam.

This means that the condensing cycle can be designed around a specific horsepower demand, whereas the co-generation cycle should be designed around the process steam demand and shaft horsepower produced complementary to it.

The intention in the above example is not to represent one system as being superior to another, but to indicate the relative operating cost of one compared to the other. The optimum system for any specific application can only be assessed on a site-by-site basis.

PROCESS POWER RECOVERY

With the exception of steam produced to generate electricity in power stations, the primary demand for steam is to provide useful heat to a process. Boilers usually produce steam at a higher pressure than is used by the process equipment, and a pressure reducing station as shown in fig 4 is used to reduce the steam pressure. The pressure reducing valve does not waste energy in terms of heat. The pressure reduction is isenthalpic, i.e., steam leaving the valve has the same enthalpy as before the valve. However, the pressure reduction has wasted the potential energy in the steam to perform work.

In fig 5, the pressure-reducing valve has been replaced by a single stage turbine which converts the potential energy in the steam into useful shaft horsepower. The turbine shaft horsepower can be directly used to drive a pump, fan, or compressor replacing electric motors, or where this is not feasible, a turbine can drive a generator to reduce power purchased from the utility.

Comparing the annual operating cost of the pressure reducing valve in fig 4 versus the back pressure turbine in fig 5, presents an example of the energy savings which are possible.

1. Pressure Reducing Valve

In the process steam cycle shown in fig 4, 25,000 lb./hr. of steam is produced at 150 psig and reduced to process pressure of 15 psig.

A. Cost of producing steam from equation (4) using #6 fuel oil:

$$\text{Steam Cost} = \frac{(1195.6 - 148) \times 3.356}{.85 \times 1000}$$

$$= \$4.14/\text{mlb.}$$

For annual operating period of 8,000 hours, total steam cost:

$$\text{Annual Steam Cost} = \frac{4.14 \times 25{,}000 \times 8{,}000}{1{,}000}$$

$$= \$828{,}000$$

2. Back Pressure Turbine

In this cycle shown in fig 5, 26,700 lb./hr. of steam is produced at 150 psig and expanded through a back pressure turbine to process pressure of 15 psig.

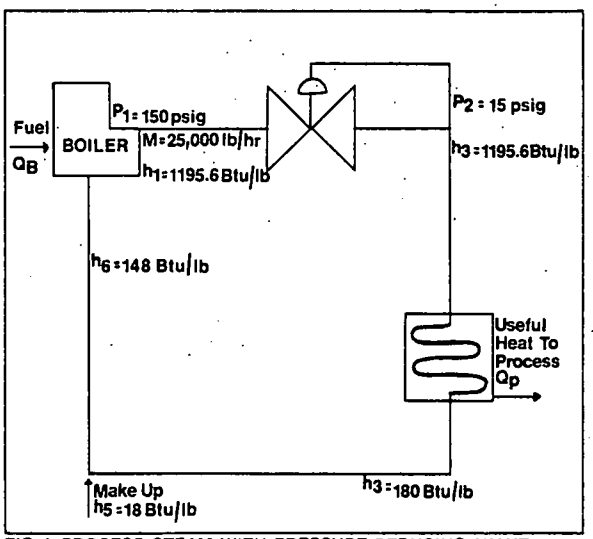


FIG.4 PROCESS STEAM WITH PRESSURE REDUCING VALVE.

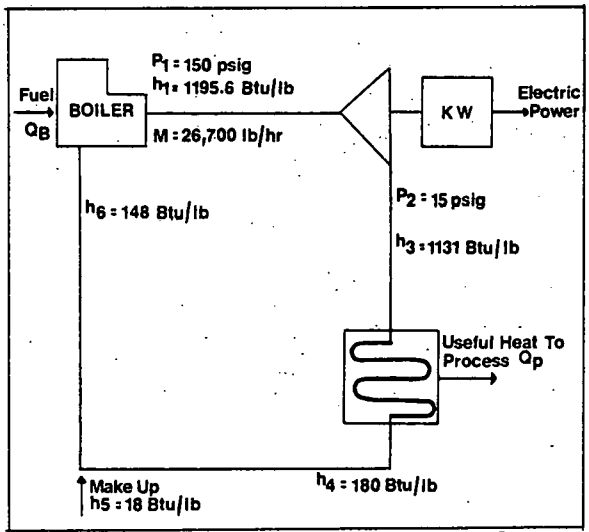


FIG.5 BACK PRESSURE TURBINE GENERATOR REPLACES PRESSURE REDUCING VALVE.

A. From equation (1), HP produced by a single-stage turbine with 50% efficiency is given by:

$$HP = \frac{26,700 \times .5 \times (1195.6 - 1066)}{2545}$$

$$= 680$$

B. Heat remaining in the exhaust steam is given by equation (3).

$$h_3 = 1195.6 - .5 \times (1195.6 - 1066)$$

$$= 1131 \text{ BTU/lb.}$$

C. Heat supplied to the process is given by:

$$Q_p = M \times (h_3 - h_4) \qquad - - (11)$$

The steam flow must be increased to maintain the same process heat at the reduced enthalpy of the turbine exhaust:

$$M = \frac{25,000 \times (1195.6 - 180)}{(1131 - 180)}$$

$$= 26,700 \text{ lb/hr.}$$

D. Annual cost of producing steam:

$$\text{Annual Steam Cost} = \frac{4.14 \times 26,700 \times 8,000}{1,000}$$

$$= \$884,300$$

E. If the HP produced is converted into KW by means of a generator, the electricity produced is given by:

$$kWh = HP \times .746 \times E_g \times \text{hrs.} \qquad - - (12)$$

F. The reduction in purchased electricity cost at \$0.04/kWh for annual operation of 8,000 hours with 90% generator efficiency is given by:

$$= 680 \times .746 \times .9 \times 8,000 \times .04$$

$$= \$146,100$$

G. Total annual operating cost is given by:

$884,300 - 146,100 = \$738,200$

H. Annual savings compared with pressure reducing valve paragraph (A):

$828,000 - 738,200 = \$89,800$

STEAM TURBINES VS. ELECTRIC MOTORS

In general terms, a steam turbine can drive anything an electric motor can drive and has certain very definite advantages:

Turbine speed can be matched to optimum speed of driven equipment.
Variable speed can be achieved over a wide range (up to 5-1).
High starting torque.
Non-overloading.
Suitable for automatic startup.
Suitable for hazardous areas.

The question here is, does the turbine provide lower cost HP than the electric motor and, as we have seen in the previous examples, this will depend on the specific installation.

The cost of operating an electric motor is given by:

$$\text{Cost/HP} = \frac{.746 \times \$/\text{kWh}}{E_m} \qquad -- (13)$$

which based on electricity cost of $0.04/kWh and electric motor efficiency of 85%:

$$= \frac{.746 \times .04}{.85}$$

$$= \$.035/\text{HP}$$

This compares with the condensing turbine from fig. 2 at $.044/HP and the back pressure turbine from fig. 3 at $0.01/HP based on oil fired boilers at $0.50/gal.

Because of the number of variables, this is best compared graphically and fig. 6 is included to show an approximate comparison of annual operating cost per HP based on:

The condensing turbine, from equation (5)

$$\$/\text{HP-YR} = \frac{M \times \$/\text{mlb} \times 8000}{\text{HP} \times 1000}$$

The back pressure turbine, from equation (10)

$$\$/\text{HP-YR} = \frac{2545 \times \$/\text{mlb} \times 8000}{(h_1 - h_6) \times 1000}$$

The electric motor, from equation (13)

$$\$/\text{HP-YR} = \frac{.746 \times \$/\text{kWh} \times 8000}{E_m}$$

Referring to fig. 6, the cost of operating back pressure turbines exhausting to useful process is shown by the area (A) (B) which for most plants presents a large operating cost advantage over the electric motor.

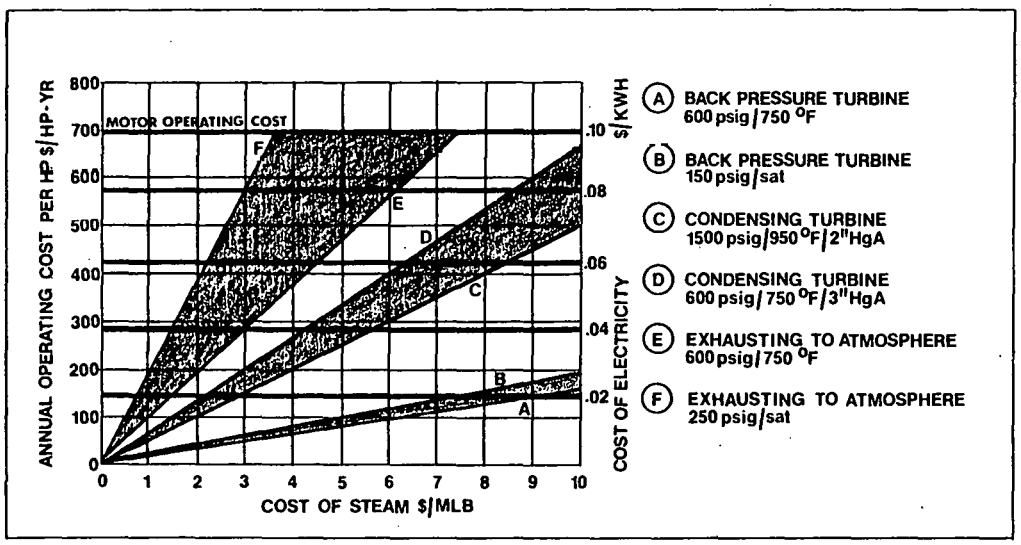


FIG. 6 COMPARISON OF STEAM TURBINE VS. ELECTRIC MOTOR OPERATING COST.

The area enclosed by (C) (D) represents typical operating cost for small multistage condensing turbines and selection on the basis of fuel cost has to be analyzed very carefully site by site. There is very close correlation between the condensing turbine and electric motor operating cost using typical fuel and electricity charges. In addition to the fuel cost, supervisory, maintenance and auxiliary power costs have to be considered.

The turbines exhausting to atmosphere shown by the area (E) (F) will, in almost all cases, have operating costs far in excess of the electric motor operating cost.

This wide difference in operating cost between exhausting to useful back pressure and exhausting to atmosphere clearly demonstrates the importance of matching the rating of mechanical drive turbines which are required for continuous service against the continuous process steam demand.

Where the steam demand to the process is subject to fluctuation, steam turbines can still produce cost effective horsepower by:

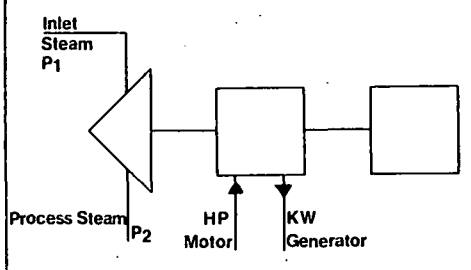
Using mechanical drive turbines with motor standby for operation during low process steam demand.

Using mechanical drive turbine in tandem with an induction motor as shown in fig 7. This provides an extremely flexible arrangement where the turbine always produces power to meet the exact steam requirements of the process. If this is higher than the driven equipment, then the induction motor becomes a generator. As process steam demand falls, it reverts to being a motor to maintain continuous output from the driven equipment.

Using turbine generator sets, which again can match KW output to process steam demand without compromising mechanical drives, which are required for continuous operation.

Using an extraction condensing turbine in which steam is extracted at the process pressure and as process steam demand fluctuates any additional steam required to meet the driven equipment HP is exhausted to a condenser.

This arrangement has the flexibility of always maintaining both continuous shaft HP demand and process steam demand. The main drawback is that any portion of the HP which is provided by the condensing mode is at the higher cost associated with a condensing turbine and has to be compared carefully with electric motor operating cost.



Process Steam Demand %	Turbine HP %	Motor HP %	Generator KW %	Driven Equip. Load %
100	100	0	100	0
100	100	0	0	100
65	50	0	50	0
65	50	50	0	100
0-30	0	0	0	0
0-30	0	100	0	100

FIG.7 TANDEM DRIVE BACK PRESSURE TURBINE WITH INDUCTION MOTOR/GENERATOR.

WASTE HEAT RECOVERY

Wherever waste heat can be converted into steam by means of a waste heat recovery boiler, the addition of a steam turbine to the waste heat recovery system can improve the payback; in some cases this can make the difference between a feasible and a nonfeasible energy-saving project.

For a plant where there is no requirement for low pressure steam, the turbine can provide the means of converting waste heat into a usable form of energy, either in terms of mechanical horsepower or electricity from a turbine generator set.

The following example indicates the improved payback which can be obtained by including a turbine with a waste heat recovery boiler:

1. Waste heat recovery boiler producing low pressure process steam.

   In fig 8 the waste heat boiler extracts heat from the exhaust gases of a fired heater at the rate of 20mm Btu/hr. and produces 19,750 lb./hr. of steam at 25 psig.

   A. This replaces steam previously supplied by an oil fired boiler, with 85% efficiency, the cost of producing steam from equation (4) was:

$$\$/\text{mlb.} = \frac{(1170 - 148) \times 3.356}{.85 \times 1000}$$

$$= \$4.035/\text{mlb.}$$

   B. The reduction in fuel cost resulting from the introduction of the waste heat boiler for annual operation of 8000 hours, is given by:

$$= \frac{4.035 \times 19{,}570 \times 8000}{1000}$$

$$= \$631{,}720/\text{yr.}$$

2. Waste heat recovery boiler producing process steam in conjunction with a back pressure turbine.

   In fig 9 the waste heat boiler again extracts heat from the exhaust gases of the fired heater at the rate of 20 mm BTU/hr., but in this example produces 18,980 lb./hr. of steam at 250 psig which is expanded through a back pressure turbine to the process pressure of 25 psig.

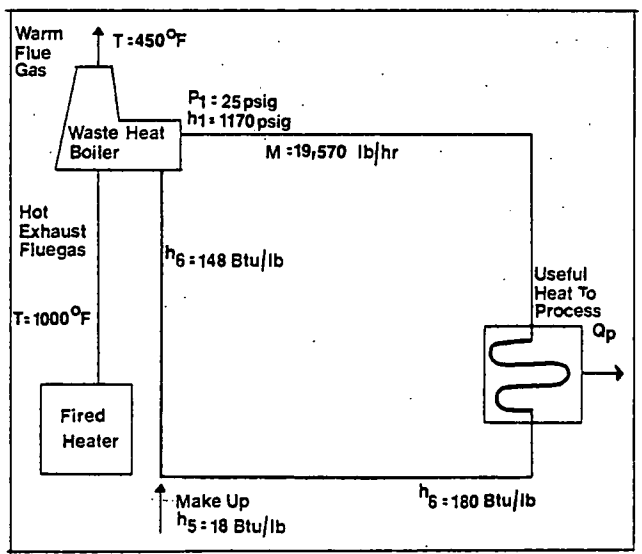


FIG.8 WASTE HEAT RECOVERY BOILER PROVIDING PROCESS STEAM.

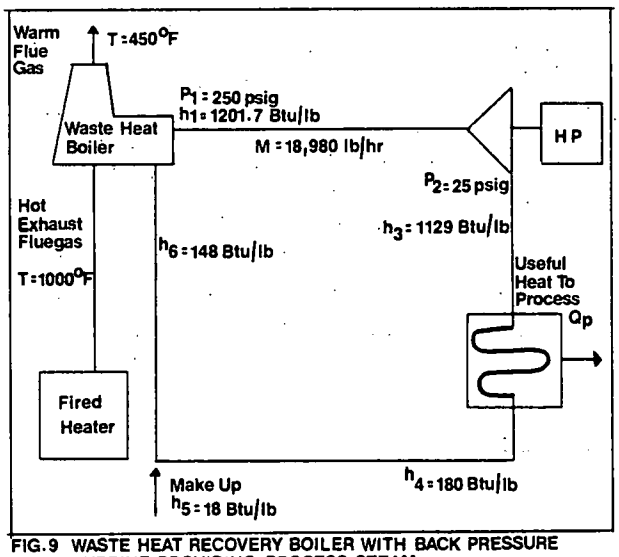


FIG.9 WASTE HEAT RECOVERY BOILER WITH BACK PRESSURE TURBINE PROVIDING PROCESS STEAM.

A. The HP which is produced by a single stage turbine with 50% efficiency is given by equation (1):

$$HP = \frac{18,980 \times .5 \times (1201.7 - 1056.3)}{2545}$$

$$= 542$$

B. The heat remaining in the turbine exhaust, from equation (3):

$$h_3 = 1201.7 - .5 \times (1201.7 - 1056.3)$$

$$= 1129$$

C. The exhaust steam provides process heat, Q_p, which is given by equation (9):

$$Q_p = 18,980 \times (1129 - 180)$$

$$= 18,012,020 \text{ Btu/hr.}$$

D. The process heat was previously supplied by the oil fired boiler, with 85% efficiency, at 25 psig and the equivalent steam flow was:

$$M = \frac{18,012,020}{(1170 - 180)}$$

$$= 18,194 \text{ lb./hr.}$$

E. The reduction in fuel cost for annual operation of 8000 hours:

$$= \frac{4.035 \times 18,194 \times 8000}{1000}$$

$$= \$587,300/yr.$$

F. The reduction in purchased electricity if the turbine replaces an electric motor with 85% efficiency from equation (13):

$$= \frac{542 \times .746 \times .04 \times 8000}{.85}$$

$$= \$152,219$$

G. Total annual reduction in fuel and electricity cost:

$$587,300 + 152,219 = \$739,519$$

which is an additional $107,800 more than the waste heat boiler without the steam turbine.

SUMMARY

The steam turbine represents an excellent means for energy savings with the correct application.

The back pressure turbine has the greatest potential to save energy, but turbine horsepower must be matched to the low pressure steam demand.

A condensing turbine provides a means of converting wasted energy into useful horsepower or kilowatts when low pressure steam cannot be utilized.

In general terms with typical fuel costs, the potential to conserve energy using steam turbines should be considered in the following order of preference:

Waste fuel
- Back pressure turbine
- Condensing turbine
- Exhausting to atmosphere

Conventional fuel
- Back pressure turbine
- Back pressure turbine with induction motor/generator
- Extraction/condensing turbine
- Condensing turbine, only if steam cost is less than electricity cost

Direct mechanical drive is preferable to the turbine generator when comparing similar sizes because motor and generator efficiencies are eliminated. However, the turbine generator has the flexibility to match power output with the process steam demand.

In the end analysis, the potential to save energy has to be established on a site-by-site basis. The number of variables which can affect the above examples is endless. All we can hope to do is provide some basic ground rules and identify specific areas which are worth further investigation.

NOMENCLATURE

HP	=	Mechanical Output
1 HP	=	2545 Btu/hr.
KW	=	Electrical Output
1KW	=	3413 Btu/hr.
kWh	=	Unit of electricity
M	=	Steam flow (lbs./hr.)
E_t	=	Turbine efficiency
E_b	=	Boiler efficiency
E_g	=	Generator efficiency
E_m	=	Electric motor efficiency
h_1	=	Inlet enthalpy (Btu/lb.)
h_2	=	Isentropic enthalpy at exhaust pressure (Btu/lb.)
h_3	=	Actual exhaust enthalpy (Btu/lb.)
h_4	=	Condensate enthalpy after process (Btu/lb.)
h_5	=	Make up feed water enthalpy (Btu/lb.)
h_6	=	Boiler feed water enthalpy (Btu/lb.)
$/mmBtu	=	Fuel cost in dollars per 10^6 Btu heating value
$/mlb	=	Steam cost in dollars per 1,000 lb.
$/kWh	=	Electricity cost in dollars per kWh
$/HP-YR	=	Annual operating cost per HP
Q_A	=	Heat lost to atmosphere (Btu/hr.)
Q_B	=	Heat supplied to boiler (Btu/hr.)
Q_{HP}	=	Heat converted to HP (Btu/hr.)
Q_P	=	Heat supplied to process (Btu/hr.)

LARGE FIELD-ERECTED AND PACKAGED HIGH-TEMPERATURE-WATER (HTW) GENERATORS FOR COAL FIRING

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ABSTRACT

The purpose of the paper is to disseminate information on the energy savings possible with High Temperature Water (HTW) for heating and industrial process application and to provide information on coal fired HTW generator design and availability.

LARGE FIELD ERECTED AND PACKAGED HIGH TEMPERATURE WATER (HTW) GENERATORS FOR COAL FIRING

In keeping with the purpose of these conferences, being the exchange of technical information for the benefit of all, I shall endeavor to present the advantages of high temperature water (HTW) applications and some basic design considerations for high temperature water generators both from the water flow side and furnace side exposed to the products of combustion.

HIGH TEMPERATURE WATER:

Before we discuss high temperature water generator design, some introductory remarks would be in order since its advantages, system design and operation is not as well known as steam. In all cases high temperature water can be used any place where steam is used for heating and process applications. High temperature water, widely used in Europe, was not used in the United States in any applications of note until mid to late 1930 and then on a limited scale. High temperature water did not make any significant gains in the United States until the early 1950's when generators of the LaMont type (see Fig. No. 1-5) became commercially available.

THE ADVANTAGES OF HIGH TEMPERATURE WATER:

Substantial savings in fuel cost - as much as 20% or more over steam systems are possible. The savings can be calculated from the steam tables. For example, heat loss in percent of total heat input with a steam pressure of 150 PSIG, based on a perfect return temperature of 212° F, the theoretical flash loss is 17-1/2% of the heat input. The heat loss is higher in actual operation as the condensate returns at a temperature of less than 212° F. Heat loss calculations for this condition and other pressures are shown in Table No. I below.

TABLE NO. 1 - HEAT LOSSES DUE TO FLASH-OFF FROM CONDENSATE

Gage Pressure (psig)		50	100	150	200	250	300
Saturated steam temperature (F)		297	338	366	388	405	422
Total Heat above 32° F.(btu/lb)	A	1179	1190	1196	1199	1202	1203
Heat of liquid (btu/lb)	B	267	309	339	362	382	399
Latent heat (btu/lb)	C	912	881	857	837	820	804
Hot well temp.(°F @ atmos pres)	D	212	212	212	212	212	212
Heat of condensate (btu/lb. @ atmos. pres)	E	180	180	180	180	180	180
Heat loss in flash-off (btu)B-E	F	87	129	159	182	202	219
Weight loss in flash-off(lb)F/970	G	0.0897	0.133	0.163	0.188	0.208	0.226
Weight of condensate recovered (LB) 1.0 - G	H	0.910	0.867	0.837	0.812	0.792	0.774
Heat added to condensate (btu) (A-E) X H	J	909	875	850	828	809	791
Heat added to make-up (btu 70°F. Feed) (A-38) x G	K	102.3	153	188	218	242	263
Heat added (total btu/lb) J+K	L	1011	1028	1038	1046	1051	1054
Heat not absorbed in user (btu) L-C	M	99	147	181	209	231	250
Heat loss due to flash-off (% of total heat input) M/L	N	9.8	14.3	17.5	19.9	21.9	23.7
Heat loss due to flash-off (% of useful heat output) M/C	O	10.9	16.7	21.2	24.9	28.1	31.1

NOTE: The above losses per pound of steam are for flash-off only. Entire absorption of latent heat is assumed in users as is a perfect hot well temperature of 212°F at atmospheric pressure. (E.G. Hansen)
Conversion factors for SI units are given later.

Other advantages inherent in the high temperature water system are superior heat storage capacity and closer temperature control. The heat storage capacity of water per cubic foot is considerably greater than steam at equivalent saturation pressures, as shown in Table No. II (below). This inherent reserve or "fly wheel" effect permits closer temperature control and more rapid response to changing load demands.

SAVINGS IN CAPITAL INVESTMENT WITH HIGH TEMPERATURE WATER ARE:

For reasons documented above, it is apparent that smaller generator capacity can be used than required for equivalent steam plant. No allowance need be made for flash losses, pick-up or blow down losses required for HTW Generator sizing.

Water treatment equipment is minimal.
No deaerating equipment is required.

Smaller distribution pipe sizes than equivalent steam system possible.

Elimination of steam traps.

Elimination of condensate tanks and pumps.

No need to pitch, grade, and drip mains. Mains can follow natural contours.

OPERATION AND MAINTENANCE:

Additional savings in life cycle costs on the following items:

Elimination of flash losses. (1)
No loss of energy due to blow down.

Minimum feed water make-up requirements.

Flooded system under pressure inhibits against oxygen entry and corrosion of distribution system and components.

Elimination of steam traps, steam trap maintenance and loss of energy through faulty traps.

Elimination of condensate return system and system maintenance.

In a recent cost anaylsis of a coal fired system system vs a high temperature water system it was estimated that the economic advantage was in favor of the high temperature water system; in the central heating plant cost by 6.3%, and in the distribution piping cost 18.5%. A comparison of the annual operating costs including fuel cost, wages and administration cost, maintenance and material costs and amortization indicated a yearly saving of approximately 20% in favor of high temperature water. Savings in fuel cost on a life cycle of 25 and 40 years is given later.

GENERATOR CAPACITY

Technically, there is no limit to the capacity of field erected coal fired HTW Generators. For practical purposes, coal fired HTW generator capacity is limited by the capacity of the coal burning equipment currently available. The output limit of coal fired HTW Generators fired with underfeed stokers (Fig. No. 1) is 25 to 30 million btu per hour, 150 million btu per hour when fired with a water cooled vibrating grate stoker (Fig. No. 2) and 400 million btu per hour when fired with a travelling grate spreader stoker (Fig. No. 3). HTW Generators can also be fired with pulverized coal burners (Fig. No. 4) in the capacity range of 125 to 500 million btu and larger. Hot water generator capacity limits with stoker types not illustrated are 100 million btu per hour with a vibrating conveyor or oscillating grate spreader stoker and 150 million btu per hour with a travelling grate stoker.

TABLE II. COMPARISON OF RELATIVE HEAT CONTENT OF WATER

ABSOLUTE PRESSURE LBS/SQ.IN.	SATURATED TEMP. °F	RETURN TEMP. °F	DENSITY LBS/CU. FT. WATER	DENSITY LBS/CU. FT. STEAM	BTU/CU. FT. WATER	BTU/CU.FT. STEAM	HEAT CONTENT RATIO WATER TO STEAM
14.7	212	180	59.8	0.0373	1923	37.4	51.5/1
29.8	250	200	58.9	0.0724	2972	72.1	41.2/1
67.0	300	200	57.3	0.1547	5820	156.7	37.2/1
134.6	350	200	55.6	0.299	8550	306.5	27.9/1
247.3	400	200	53.5	0.537	11090	555	20.0/1
343.7	430	200	52.4	0.741	12570	768	16.4/1
566.1	480	200	50	1.222	14820	1268	11.7/1

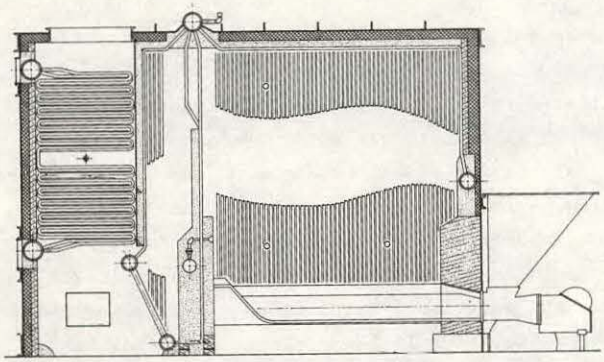


Fig. No. 1 Underfeed Stoker

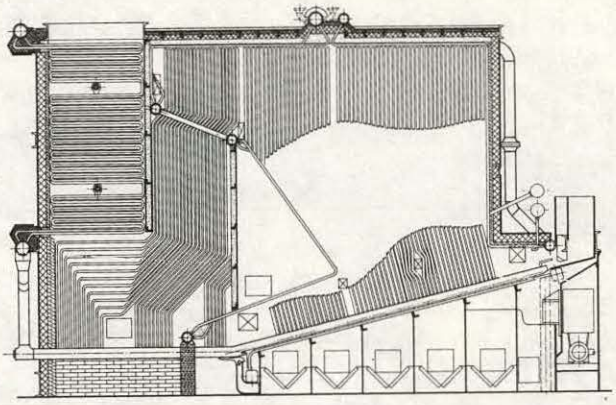


Fig. No. 2 Vibrating Grate Stoker, Water Cooled

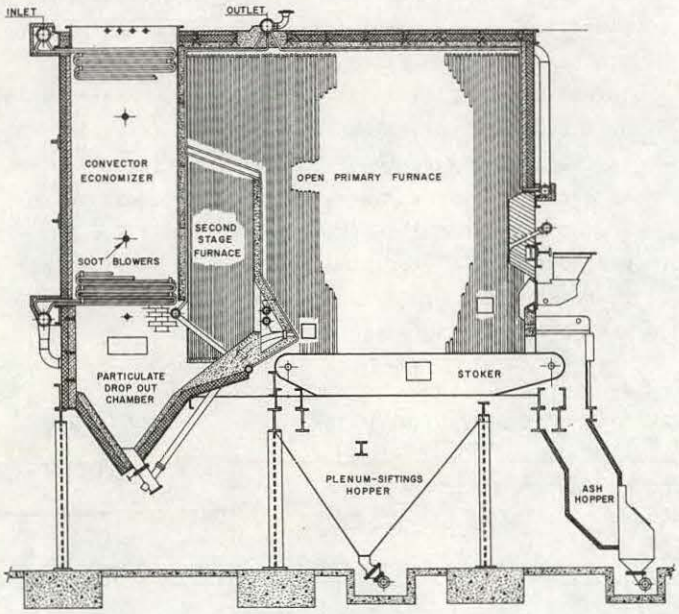


Fig. No. 3 Travelling Grate Spreader Stoker

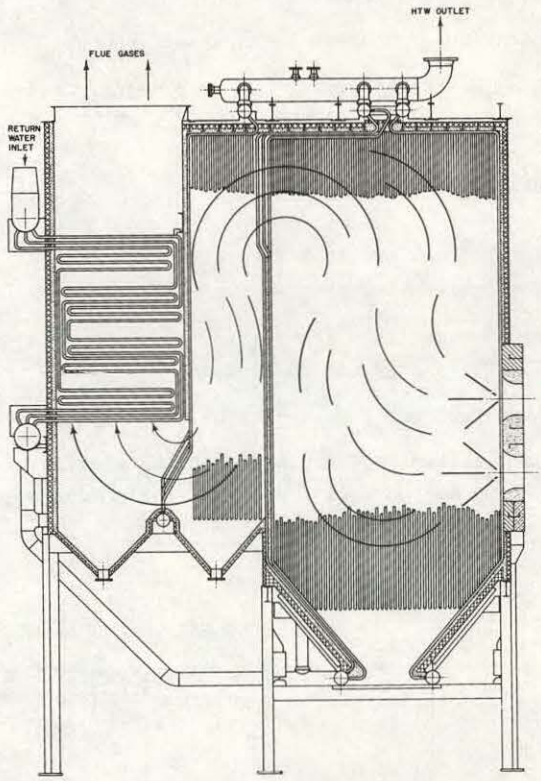


Fig. No. 4 Pulverized Coal Fired

The ideal design for a high temperature water generator is an arrangement utilizing header and tube construction with header and tube diameters limited to accommodate the required water flow and flow distribution with a reasonable pressure drop. The use of generators with excessive header sizes or drums is not recommended. Typical HTW generator header and tube arrangement is illustrated in Figure No. 3. Natural circulation steam generators are dependent on steam formation as the driving force for their circulation. The large quantities of system water circulated through the generators can be disruptive of the natural circulation patterns and can result in serious damage to the generator tubes.

The ideal high temperature water generator design would have the convection section arranged for counter flow of gas to water, gas up -- water down. This provides the greatest possible log mean temperature differential and subsequently the highest rate of heat transfer and efficiency.

The inherent benefits of high temperature water application will be fully utilized from a design, operating and economic standpoint when the systems are designed for high temperature differential. Usual temperature differentials range from 100° to 200° F. It would be well to note that where coal fired hot water generators are utilized the water temperature returning from the system to the generators should be at a sufficient temperature to keep the tube metal temperature above the dew point of the combustion gases in relation to the sulphur content of the fuel. (3)

FURNACE DESIGN

Furnace design for coal fired high temperature water generators is not significantly different than for steam generators.

The key parameter for furnace design is the coal analysis. The proximate analysis, ultimate analysis, mineral analysis, ash fusion temperatures, free swelling index, percentage of fines and ash analysis are all necessary for determining the sizing of generator furnace and convection section.

Coal ash fouling characteristics will have a bearing on the convection section tube spacing. Low grade coals should be reviewed for their slagging and fouling characteristics. For example, lignite and low grade coals high in sodium content (over 4%) will have high slagging characteristics at given temperature ranges and will present serious operational problems if the generator design does not adequately provide for this condition.

Heat release rates and exit temperatures in general can be selected from the guide line parameters listed in Table No. III. With good grades of coal or if the slagging and fouling characteristics are known, it is possible for release rates to be increased over the guide lines listed in Table III allowing for a less conservative, less costly generator design; however, the stoker release rates will remain essentially the same.

TABLE III BASIC FURNACE DESIGN PARAMETERS
FOR HIGH TEMPERATURE WATER GENERATORS
FIRED WITH TRAVELLING GRATE SPREADER STOKERS

AT MAXIMUM CONTINUOUS RATING	MID-WEST COAL	SUB-BITUMINOUS	LIGNITE
Furnace volume release rate K BTU/CU.FT./HR.	20 - 35	20 - 30	15 - 20
Furnace projected surface[1] release rate K BTU/SQ.FT./HR.	60 - 80	65 - 75	Max. 65
Furnace exit temperature °F	1950	1850	1700
Convector exit temperature ° F	350 min.	352 min.	325 min.
Grate surface release rate BTU/SQ.FT./HR.			
Maximum Continuous	750,000	750,000	750,000
Minimum Continuous	625,000	625,000	625,000
Minimum Release	250,000	250,000	250,000
Max. @ 2 Hr. Peak	825,000	825,000	825,000

[1] ABMA/ASME Standard Practice

Conversion factors for S.I. units for Table No. III are given later.

PACKAGED GENERATOR CAPACITY

Coal fired packaged hot water generators currently are limited to a maximum capacity of 50 million btu per hour when fired with a good grade of coal and are derated proportionately for low rank coals. Particulate emission standards also have placed constraints on size of packaged coal fired high temperature water generator designs.

BASIC HIGH TEMPERATURE WATER GENERATOR DESIGN

WATER FLOW

High temperature water generators should be of the controlled forced circulation type. (1) (2) (4) water flow should be regulated to the heat absorbing surfaces in proportion to their heat absorption rate. This can be accomplished by limiting the number of paths in parallel or the use of metering orifices designed to provide for equalization of water flow through the tube circuits or a combination of both methods. (2)

Convective and radiant heat absorbing surfaces in the generator tube circuits should be arranged in series for better control of water flow, uniform temperature rise and ease of balancing the tube circuits. Down flow of water in the radiant heat absorbing tube circuits in the primary furnace should be avoided. Schematic water flow of typical HTW Generator is illustrated in Fig. No. 5 below:

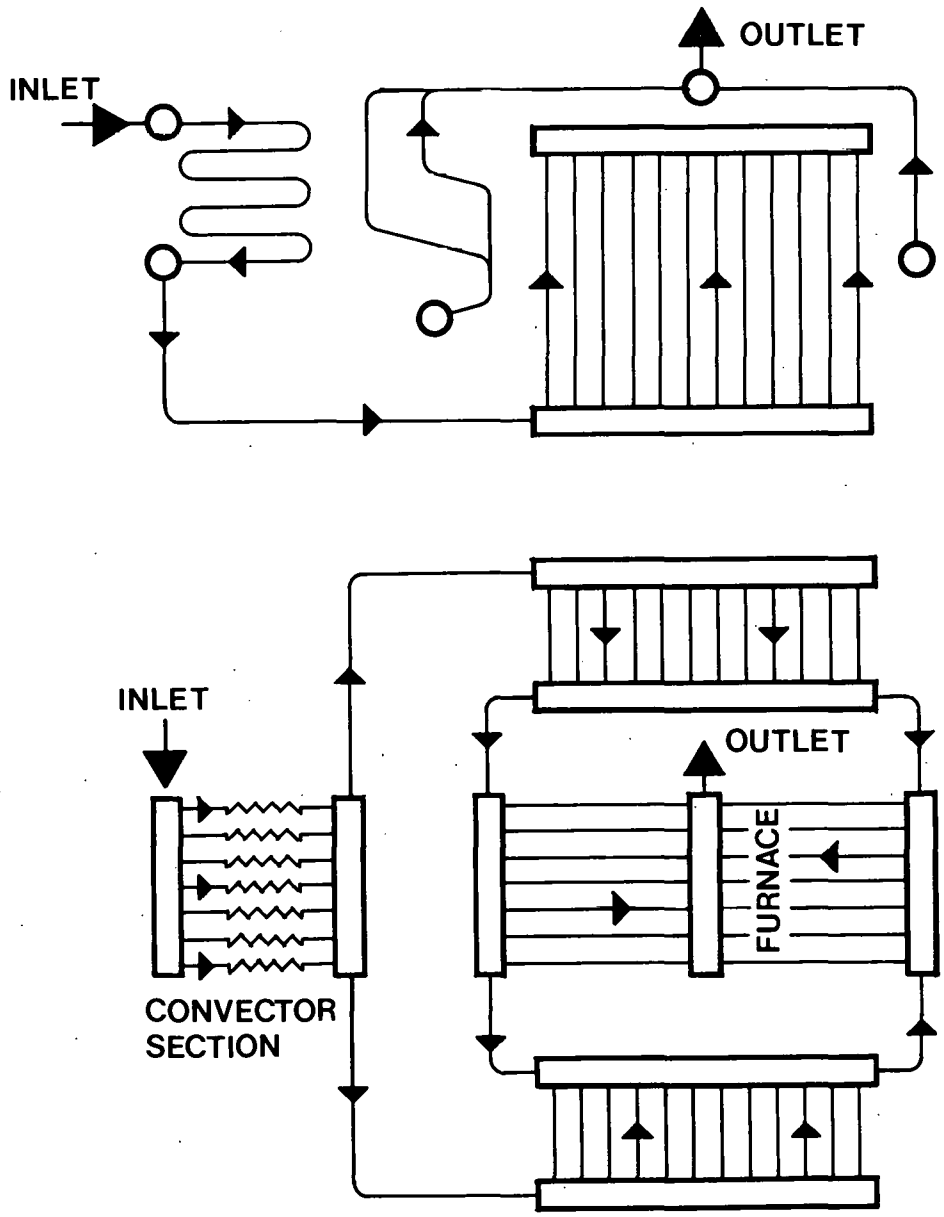


FIG. NO. 5 SCHEMATIC WATER FLOW TYPICAL HIGH TEMPERATURE WATER GENERATOR

In summation, the use of HTW for heating and process can provide substantial savings in capital and fuel costs and savings in maintenance and other operating costs over the life of the plant.

High temperature water is ideal for large district heating systems and for industrial, commercial and institutional heating and process applications and co-generation. (5)

HTW Generators should be of the controlled forced circulation type with tube and header construction. HTW Generators should have the convective and radiant circuits arranged in series for uniform temperature and to facilitate balancing of the tubular circuits.

The design of a coal fired HTW Generator or direct fired steam boiler should not be attempted without an accurate fuel analysis; otherwise, the designer is likely to over design adding unnecessarily to the cost of the generator and its fuel burning and ancillary equipment and, alternately, a less conservative design could result in a plant with unacceptable operating conditions.

A life cycle fuel cost HTW VS STEAM is illustrated below:

DATA

CAPACITY OF PLANT: 200,000,000 BTU/HR.
TEMPERATURE: 400° F/240 PSIG OPERATING PRESSURE
STANDBY AND OPERATING FACTOR: 66.67%
HOURLY OPERATION: 50% OF YEAR - 4,380 HRS/YEAR©
STEAM SYSTEM EFFICIENCY: 61.6%
HOT WATER SYSTEM EFFICIENCY: 81.8%
COAL HEATING VALUE: 11,000 BTU/LB.
COAL COST: $35/TON
LIFE CYCLE: 25 YEARS/40 YEARS

EVALUATION

FUEL INPUT

STEAM

$$\frac{\text{200,000,000 BTU/HR. X 0.667 (STANDBY)}}{\text{0.616 (EFF.)X11,000 BTU/LB.X2000\#/TON}} = 9.82 \text{ TONS/HR}$$

HOT WATER

$$\frac{\text{200,000,000 BTU/HR. X 0.667 (STANDBY)}}{\text{.818(EFF.)X11,000 BTU/LB.X2,000\#/TON}} = 7.40 \text{ TONS/HR.}$$

FUEL SAVINGS TO HTW---------- = 2.42 TONS/HR.

4380 HRS. x 2.42 TONS/HR. x $35 TON =

$370,986. FIRST YEAR SAVING HTW

THEREFORE SAVINGS ARE:

25 YEARS - 25 X $370,986 = $9,274,986.00

40 YEARS - 40 X $370,986 = $14,839,440.00

ANNUITY EVALUATION FOR HTW SAVINGS

WORTH OF SAVINGS (S) FROM FUEL SAVINGS IN PERIOD FOR (N) NUMBER OF YEARS (25-40 YEAR LIFE CYCLE) WITH FUEL COST ESCALATING AT RATE (R) (5% PER YEAR).

$S = Y \times V$

WHERE Y IS FIRST YEAR SAVING

$V = (1 + R/100)^{N} - 1) \div R/100$

25 YEARS V = 47.72 40 YEARS V = 120.80

THERFORE, SAVINGS ARE: 25 YRS. - 47.72 x $370,986 = $17,703.450.00

40 YRS. - 120.80 x $370,986= $44,815.109

THE FUEL ESCALATION WAS ESTIMATED AT 5%, AND IF IT EXCEEDS 5%, THE SAVINGS WILL BE EVEN GREATER.

CONVERSION FACTORS FOLLOW FOR TABLES I - II - III

TABLE NO. I - TO SI UNITS

Tabular Units Factor = SI Units
Gage Pressure PSI x .0703 = KGS./SQ.CM.
° F. ° C. = 5/9 (F-32) = ° C.
Btu/Lb. x 0.0556 - CAL/GRAM
Lb. x 453.59 = GRAMS

TABLE NO. II - TO SI UNITS

Tabular Units Factor = SI Units
Absolute Pressure/lbs/sq.in. x 0.0703 = KGS./SQ.CM.
° F. °C. = 5/9 (F-32) = ° C.
Lbs/Cu.Ft. x 0.01602 = GRAMS/CU. CM.
CU. FT. X 28,320 = CU. CM.

TABLE NO. III - TO SI UNITS

BTU/CU.FT./HR. x 0.0089 = CAL./CU.M/HR.

$BTU/HR/FT.^2 \times 0.271 = CAL./HR/CM^2$

0° C. = 5/9 (F-32) = °C

B I B L I O G R A P H Y

(1) Hansen, E. G. "HTW Systems --- Layout and Utilization" Actual Specifying Engineer - January, 1959.

(2) Federal Construction Council Technical Report No. 37 - 1959 "High-Temperature Water for Heating and Light Process Loads" BRAB Division of Engineering and Industrial Research - National Academy of Sciences.

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(4) Sulthorpe, William L. Design of High Pressure Steam and High Temperature Water Plants. Industrial Press 1972.

(5) Strauss, Sheldon D. "District Heating Links with Cogeneration" Power, August 1979.

CHOOSING POWER CABLES ON THE BASIS OF ENERGY ECONOMICS

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ABSTRACT

Feeder circuit and branch circuit cable sizes are determined primarily on the basis of ampacity and voltage drop considerations. Rising costs of energy suggest a reassessment of currently used voltage drop criteria. Some degree of cable oversizing reduces cable resistance and cable operating temperature resulting in lower cable losses. A simplified method of analysis is presented which incorporates the effects of cable operating temperature. The analysis permits determination of cable loss savings for various choices of cable sizes. The method is extended to include cost of cable and expected future costs of energy so that an economical choice of cable size may be determined. An example is presented to illustrate the method. It is shown that a relatively simple modification of currently used ampacity tables permits determination of cable sizes taking into account today's energy economics.

INTRODUCTION

Rapid increases in the cost of energy have stimulated renewed interest in measures to reduce losses whereever possible. A recent study estimates that of the total energy consumed in industrial processes, that amount consumed in losses due to electrical system components may be as high as 20% [1]. This same study sets forth ranges of losses typical for various electrical system components. Cable losses are seen to be significant. They range from roughly 1 to 4 percent of the total energy transmitted [1]. Anticipated increases in the demand and cost of electrical energy suggest the importance of measures to minimize these losses. For example, electrical energy sales in the U.S. exceeded two trillion kilowatt hours in 1978 and are expected to exceed four trillion kilowatt hours in the year 1995 [2]. The cost of electrical energy is expected to triple over the same time frame which could bring the cost to over 15 cents per kilowatt hour in 1995 [3]. Cable loss reductions will represent increasingly significant savings in the very near future.

Typically, cables are sized for a particular requirement on the basis of ampacity and voltage regulation while other factors such as the short circuit rating of the cable and allowable cable tension in pulling must also be checked [4]. Ampacity limits are essentially thermal limits which define for a particular installation the amount of current a cable can carry without damage to or significant shortening of insulation life. Voltage regulation limits are generally dictated by load voltage requirements. In general, the longer a cable is the lower the voltage will be at the receiving end for a particular load current requirement. Ampacity tends to dictate the cable choice on relatively short cables and voltage regulation comes into play on longer cable runs. Over the years code-dictated limits on voltage regulation have evolved. It has been suggested that tighter limits on voltage regulation than those actually required by a given code may be justified on the basis of economics [1]. Similarly, it may be economically justifiable to limit cable current to values somewhat lower than those permissible on the basis of ampacity [4]. For a given load requirement we are essentially dealing with the question of increasing cable size over that which would be minimally required to satisfy either ampacity or voltage regulation requirements. The added cable cost will be offset by reduced cable losses and corresponding savings in energy costs. Essentially, as cable size is increased cable resistance (and hence I^2r loss) goes down. The reduction in resistance is due to larger cable cross section and reduced cable operating temperature.

This paper sets forth a procedure for determining economical cable sizes which takes into account expected future costs of energy, interest rate, life of the cable, initial cable cost and cable operating temperature. Sensitivity of the choice to changes in these variables is also considered. The procedure is illustrated for a particular cable type and voltage

class.

CABLE LOSSES AND OPERATING TEMPERATURE

If copper losses predominate total losses per unit length are given by

$$q = 3I^2r \quad (1)$$

for a three conductor cable where q is cable loss in watts per unit length, r is resistance in ohms per unit length and I is rms current in amperes. Conductor resistance varies linearly with temperature and the dependence is generally expressed in the following way [5]:

$$\frac{r_2}{r_1} = \frac{T + t_2}{T + t_1} \quad (2)$$

The parameters r_1 and r_2 are resistances per unit length at temperatures t_1 and t_2 respectively. T is a constant determined by the conductor material. Assuming we know r_1 at temperature t_1 equation (2) can be rewritten as

$$r = mt + b \quad (3)$$

where r is the resistance per unit length of the cable at operating temperature t. The constants m and b can be calculated to take into account the effects of stranding and skin effect. Steady state heat flux in watts per unit length is assumed to be linearly related to total cable conductor temperature rise above some ambient temperature t_o:

$$q = k(t - t_o) \quad (4)$$

Equation (4) expresses an "Ohm's Law" type relationship between heat flux q and temperature difference $t - t_o$. Essentially, q is analogous to electrical current, $t - t_o$ to a potential difference and the constant k to electrical conductance. Cable ampacity can be determined by combining (1) and (4) if r is taken at temperature t and t is set equal to some allowable temperature based on the cable insulation. The problem is not an easy one since the constant k is difficult to determine and very much dependent on the actual installation. Typically, the reciprocal of the thermal conductance k is taken as the sum of a number of thermal resistances. For example, we might consider thermal resistance between cable conductors and cable sheath, between cable sheath and the duct bank and between the duct bank and earth assumed to be at the ambient temperature t_o [6]. Assuming we have ampacity tables at hand for the cable class of interest, the reverse problem is considerably simpler. We can assume the set of conditions on which the ampacity tables are based to determine the constant k. Once k is known simultaneous solution of (1), (3) and (4) for any current I yields cable operating temperature t, resistance r and losses q. Specifically, we can calculate losses per unit length for a particular cable recognizing the benefits of reduced operating temperature.

COMPUTATION OF TOTAL CABLE COST

For a particular value of cable current we can calculate cable losses in watts per unit length as described above. By making assumptions about the cable loading cycle we can compute annual losses and express them in kilowatt hours per unit length. The cost of these losses over the life of the cable has a certain present worth which depends on the cost of energy over the life of the cable. If this present worth of losses is added to the purchase price of the cable, we arrive at a total cable cost which includes initial cable cost and cost of losses over the life of the cable. This cost can be used to determine the most economical cable size for a particular load current requirement.

If the cost of energy per kilowatt hour is assumed to be constant over the life of the cable, the annual cost of losses per unit length will be constant over the life of the cable. Annual cost of losses per unit length is determined by simply multiplying the annual losses per unit length by the assumed constant cost of energy. If we denote this annual cost of losses per unit length as acl, the present worth, pw, of these losses is given by:

$$pw = acl \ \frac{(1 + i)^n - 1}{i(1+i)^n} \quad (5)$$

In the above expression, i is the assumed interest rate and n is the assumed life of the cable in years. The term in brackets is the uniform series present worth factor.

In reality, we anticipate that the cost of energy will increase over the life of the cable. Therefore, the annual cost of losses per unit length will increase over the life of the cable. If we assume that cost of energy increases linearly we can calculate a present worth of losses as

$$pw = acl' \ \frac{(1 + i)^n - 1}{i(1+i)^n} \quad (6$$

In the above expression acl' is an equivalent uniform

annual cost of losses per unit length given by

$$acl' = cl + g\left[\frac{1}{i} - \frac{n}{(1+i)^n - 1}\right] \qquad (7)$$

In (7) cl is the annual cost of losses per unit length for the first year and g is the annual increase in cost of losses. Fig. 1 below illustrates the concept.

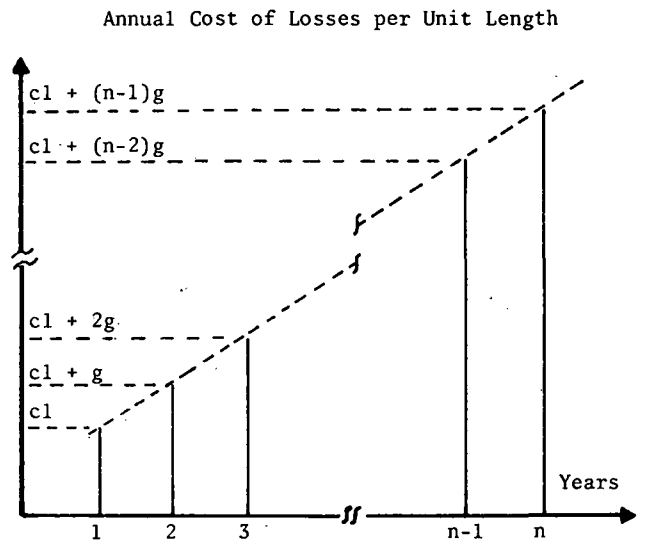


Fig. 1 Illustration of Terms in Equation 7.

In essence (5) gives present worth of losses by the uniform series present worth method and (6) gives present worth of losses by the uniform gradient series present worth method [7].

AN ILLUSTRATIVE EXAMPLE

Use of the foregoing concepts in choosing cable sizes is perhaps best illustrated by an example. Suppose we consider selection of cable sizes for 5 KV class three conductor belted paper insulated cable. Characteristics are shown in table 1 below.

TABLE 1
Cable Data for Three Conductor Belted Paper Insulated Cable

Cable #	Cable Size Circular Mils or (AWG)	Ampacity (amperes)	Resistance at 65°C Ω/ 1000 ft	Cable Cost $/ 1000 ft
1	26,250 (6)	75	0.473	705
2	41,740 (4)	98	0.299	1,068
3	66,370 (2)	128	0.187	1,641
4	83,690 (1)	146	0.149	2,232
5	105,500 (1/0)	168	0.118	2,745
6	133,100 (2/0)	192	0.094	3,360
7	167,800 (3/0)	219	0.074	4,182
8	211,600 (4/0)	249	0.059	5,220
9	250,000	273	0.050	6,210
10	300,000	304	0.042	7,485
11	350,000	334	0.036	8,520
12	400,000	359	0.031	10,050
13	500,000	408	0.025	12,120
14	600,000	450	0.021	16,410
15	750,000	505	0.017	20,310

In table 1 except for cable cost all data is taken from [8]. Ampacity in amperes is taken for an assumed load factor (ratio of average to peak current) of 100% assuming one three conductor cable in a duct bank. Ambient earth temperature is assumed to be 20°C. Rated cable temperature is 85°C. Cable costs are assumed values for the sake of the example. Typically, they would come from a vendor quote. The following additional assumptions are made:

1. 5-day per week, 16-hour per day operation is assumed.
2. Operation during the 16-hour period is at 100% load factor. The time to reach steady state cable operating temperature is assumed to be small compared to the 16-hour time period of operation.
3. Operation at the ampacity levels shown in table 1 results in a conductor temperature of 85°C.
4. Choice of cable sizes is restricted to the 15 cable sizes shown in table 1.
5. Cable life is assumed to be 30 years.
6. Interest rate is assumed to be 12%.
7. Energy cost is assumed to start at $.05 per kilowatt hour and to increase by $.00625 per kilowatt hour each year.

The assumptions listed above may appear restrictive but they are easily modified in the procedure which is described below. The effects of varying some of these assumptions will be presented later in the paper.

Using (1), (3), (4), (6) and (7), we can calculate the total cable cost per unit length. This is the sum of cable cost per unit length as shown in table 1 and the present worth of the cost of losses per unit length taken over the life of the cable.

We start by doing this for cable #15 (750,000 circular mil) for each of the currents shown in table 1. Table 2 shows results for this first step.

TABLE 2

Total Cable Cost per 1000 ft for Cable #15 (750,000 Circular Mil)

Current	Annual Losses Kilowatt Hours/ 1000 ft	Total Cable Cost Thousands of Dollars/1000 ft	Cable Temperature Degrees C
505	58,500	65.3	85.0
450	44,100	54.3	69.0
408	35,100	47.3	59.0
359	26,200	40.5	49.2
334	22,400	37.5	44.9
304	18,200	34.3	40.2
273	14,500	31.5	36.1
249	11,900	29.5	33.2
219	9,100	27.3	30.1
192	6,900	25.7	27.7
168	5,300	24.4	25.9
146	4,000	23.4	24.4
128	3,000	22.6	23.4
98	1,800	21.7	22.0
75	1,000	21.1	21.2

Note that in table 2, total cable cost goes down as we reduce cable current from 505 to 75 amperes reflecting the decrease in cost of losses. In the extreme case operation at 75 amperes reflects operation near ambient temperature with low losses and total cable cost approximately the same as the initial cable cost shown in table 1.

The next step requires development of results similar to those shown in table 2 for the remaining cable sizes. For example, we compute total cable cost per unit length for cable #14 (600,000 circular mil) starting at 450 amperes and working on down to 75 amperes. Our last table will be for cable #1 and will have only one entry, namely that value of current corresponding to operation at 100% ampacity at an operating temperature of 85°C.

Using tables similar to table 2, we can determine for each current shown in table 1 the total cable cost per unit length for each possible cable size. For our example, results of this step for a current of 98 amperes are shown in Fig. 2 below.

Note that in Fig. 2 we do not show cost for cable #1 since 98 amperes exceeds the ampacity shown in table 1 for cable #1. Fig. 2 shows that cable #8 will produce the lowest total cable cost per unit length for a current of 98 amperes. This implies an increase of six cable sizes over what we would use if we went by the ampacities shown in table 1. The savings realized by doing this are easy to calculate from data tabulated in the manner of table 2. In this case, our savings amount to $20,560/1000 ft over the cable life if we choose cable #8 instead of cable #2. The developed results for all 15 current levels shown in table 1 are shown in table 3 below.

SENSITIVITY OF RESULTS TO CHANGES IN ASSUMPTIONS

In order to determine the effects of changing the assumptions concerning cost of energy, life of the cable, interest rate and the effect of different cable operating temperatures, a computer program was written to analyze a number of cases. Results of 28 cases are presented in detail in [9]. Selected results are presented and discussed briefly in tables 4 through 7 on the following pages.

Results are most sensitive to the cost of energy over the life of the cable. This is illustrated in table 4 which shows choice of cable size based on ampacity versus choice of cable size based on minimum total cost of cable for various assumed costs of energy over the life of the cable. Also shown in table 4 is the calculated total savings realized by making the latter choice. This savings is expressed in thousands of dollars per 1000 feet of cable and represents total savings over the life of the cable. It is clear from table 4 that changes in the anticipated cost of energy significantly affect both cable choice and the amount of the total savings realizable by choosing on the basis of minimum total cable cost. Note that in table 4 as well as in other tables the use of cable number permits an easy determination of the degree of oversizing suggested in that cable #1 is the smallest and cable #15 is the largest cable considered.

Taking into account reduced cable operating temperature affects the choice of cable size very little but significantly affects the total savings. This is illustrated in table 5. In all cases, total saving we calculate by including the effects of reduced ca... operating temperature exceed those we calculate

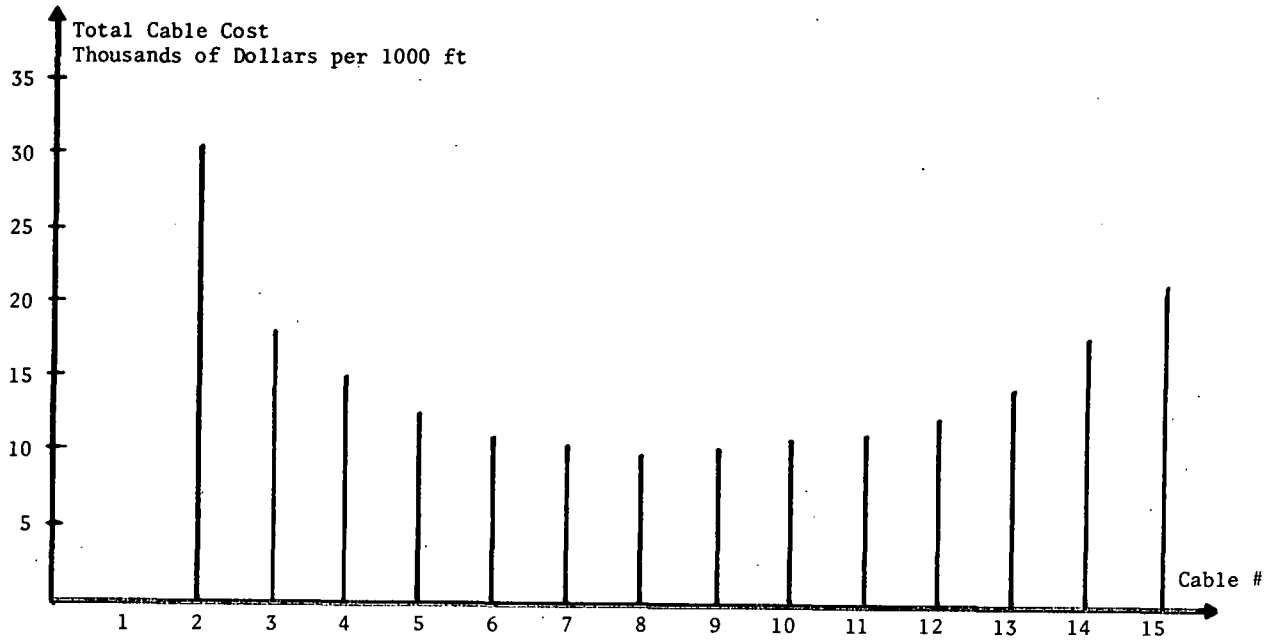


Fig. 2 Total Cable Cost for a Load Current of 98 Amperes vs Cable Size

TABLE 3

Cable Choices on the Basis of Ampacity vs Choices on the Basis of Minimum Total Cable Cost

Current (amperes)	75	98	128	146	168	192	219	249	273	304	334	359	408	450	505
Cable Choices on the Basis of Ampacity:															
Cable Choices (Cable #)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Cable Choices on the Basis of Minimum Total Cable Cost:															
Cable Choices (Cable #)	7	8	9	11	11	12	13	13	13	13	15	15	15	15	15
Total Savings Realized by Oversizing: (Thousands of dollars per 1000 ft)	20.3	20.6	19.9	19.7	19.6	18.7	18.0	16.5	15.2	13.2	12.2	11.1	8.1	6.5	0.0

TABLE 4

Effects of Changes in the Cost of Energy, 30 Year Cable Life, 12% Interest Rate

Current (amperes)	75	98	128	146	168	192	219	249	273	304	334	359	408	450	505
Cable Choices on the Basis of Ampacity:															
Cable Choices (Cable #)	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Cable Choices on the Basis of Minimum Total Cable Cost:															
Cost of Energy Level at $.02/kwhr															
Cable Choices (Cable #)	3	5	6	7	7	8	9	9	11	11	11	12	13	14	15
Total Savings (Thousands of dollars per 1000 ft)	2.8	2.4	2.0	1.9	1.6	1.3	0.9	0.5	0.3	0.4	0.0	0.0	0.0	0.0	0.0
Cost of Energy Starting at $.02/kwhr and Tripling in 16 Years															
Cable Choices (Cable #)	5	6	7	8	8	9	11	11	11	13	13	13	13	15	15
Total Savings (Thousands of dollars per 1000 ft)	6.6	6.4	5.7	5.6	5.2	4.7	4.1	3.4	2.8	2.5	2.2	1.9	0.0	0.3	0.0
Cost of Energy Starting at $.05/kwhr and Tripling in 16 Years															
Cable Choice (Cable #)	7	8	9	11	11	12	13	13	13	13	15	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	20.3	20.6	19.9	19.7	19.6	18.7	18.0	16.5	15.2	13.2	12.2	11.1	8.1	6.5	0.0

TABLE 5

Effects of Reduced Cable Operating Temperature
30 Year Cable Life, 12% Interest Rate
Cost of Energy Starting at $.05/kwhr and Tripling in 16 Years

Current (amperes)	75	98	128	146	168	192	219	249	273	304	334	359	408	450	505
Cable Operating Temperature Calculated:															
Cable Choices (Cable #)	7	8	9	11	11	12	13	13	13	13	15	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	20.3	20.6	19.9	19.7	19.6	18.7	18.0	16.5	15.2	13.2	12.2	11.1	8.1	6.5	0.0
Cable Operating Temperature Assumed Constant at 65°C															
Cable Choices (Cable #)	7	8	10	11	11	13	13	13	13	13	13	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	18.1	18.1	17.0	16.8	16.4	15.5	14.6	13.0	11.6	9.8	7.8	7.3	4.8	4.2	0.0

TABLE 6

Effects of Cable Life
12% Interest Rate
Cost of Energy Starting at $.05/kwhr and Tripling in 16 Years

Current (amperes)	75	98	128	146	168	192	219	249	273	304	334	359	408	450	505
Cable Life of 30 Years:															
Cable Choices (Cable #)	7	8	9	11	11	12	13	13	13	13	15	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	20.3	20.6	19.9	19.7	19.6	18.7	18.0	16.5	15.2	13.2	12.2	11.1	8.1	6.5	0.0
Cable Life of 40 Years:															
Cable Choices (Cable #)	7	8	9	11	11	13	13	13	13	13	15	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	21.9	22.1	21.4	21.4	21.1	20.4	19.7	18.0	16.5	14.3	13.7	12.4	9.2	7.2	0.0

assuming a constant temperature. If total savings are not of interest, a constant temperature assumption simplifies the calculations somewhat and leads to essentially the same choice of cable sizes.

Results are relatively insensitive to the expected cable life as is shown in table 6 above. Table 6 shows that cable choices remain essentially the same but total savings increase by approximately 10% if cable life is taken to be 40 years instead of 30 years.

Results for different assumptions on interest rate are illustrated in table 7. Table 7 shows that for all currents an increase in assumed interest rate will reduce the total savings realizable and will change the choice of cable size for five current levels. The decrease in savings can be explained in a simple way. When we find present worth of that portion of cable costs due to cable losses we are essentially determining the amount of money required at present to pay for future costs associated with losses. We assume that this money would be invested at the prevailing interest rate and used to pay for losses as they occur over the life of the cable. The higher the rate of interest the less we must invest to cover cost of cable losses.

DISCUSSION

The method described above for choosing cable sizes minimizes total cable cost which includes initial cost of cable and cost of cable losses over the life of the cable. Since the method is independent of the length of the cable run, the effects of choosing cables this way on voltage regulation cannot be directly stated. Since in all cases we see an increase in cable size over that which we would have if we chose sizes on the basis of ampacity, voltage regulation will be reduced. It still remains as an item which must be checked. The

TABLE 7

Effects of Assumed Interest Rate
30 Year Cable Life
Cost of Energy Starting at $.05/kwhr and Tripling in 16 Years

Current (amperes)	75	98	128	146	168	192	219	249	273	304	334	359	408	450	505
Interest Rate taken as 12%															
Cable Choice (Cable #)	7	8	9	11	11	12	13	13	13	13	15	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	20.3	20.6	19.9	19.7	19.6	18.7	18.0	16.5	15.2	13.2	12.2	11.1	8.1	6.5	0.0
Interest Rate Taken as 15%															
Cable Choice (Cable #)	6	7	9	9	11	11	13	13	13	13	13	15	15	15	15
Total Savings (Thousands of dollars per 1000 ft)	14.7	14.6	13.9	13.7	13.4	12.9	11.7	10.8	10.0	8.9	7.3	5.9	4.2	4.0	0.0

method presented appears to be a more direct attack on the problem of economical choice of cable sizes than one which would attempt to define voltage regulation limits in some way which was economically optimal.

The example presented does not address such questions as possible higher costs of installation associated with pulling larger cable, costs of maintaining reserves of larger size cable, costs of maintaining or repairing larger size cables, etc. The method does, however, quantify the total savings realizable in any given choice which should assist in including these considerations in a final selection process. The authors believe that the method could be extended to address these considerations at the expense of introducing more input variables in the program.

It is interesting to note that the procedure used to calculate a cable operating temperature is quite simple. Since the effects of cable temperature do not appear to alter significantly the choice of cable size it would appear that more elaborate procedures for calculating temperature would produce only a more accurate assessment of total savings realizable for various choices. This tentative conclusion should be verified by temperature and loss measurements in actual installations since savings cited in the example are significant.

In the example presented changes in cable choices dictated by economy occur predominantly for the smaller sized cables. This is due to the assumption that cable sizes are restricted to the 15 sizes shown in table 1. An obvious extension of the method would consider the possibility of using cables paralleled at the higher current levels. Even if we neglect the added cost of installation, permitting the use of cables paralleled requires evaluation of a significantly larger number of options as we oversize. The magnitude of the savings at the smaller cable sizes suggests that this may be worth pursuing.

CONCLUSIONS

A step by step procedure has been presented for determining cable sizes in an economical manner. The method easily determines total savings realizable for alternative cable choices. The method is sufficiently general that alternative assumptions about expected costs of energy, changes in cable costs, interest rate and expected cable life can be investigated. For the example considered it was shown that results are most sensitive to the anticipated future costs of energy. Changes in expected cable life, interest rate and operating temperature do not significantly affect the choice of cable size but do affect the calculation of total savings which might be realized by oversizing. The example further showed that under certain conditions significant cable oversizing is economically justifiable.

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CONSERVATION THEORY PROCESS CONTROL USING VARIABLE FREQUENCY DRIVES

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ABSTRACT

The purpose of this paper is to outline some of the economic considerations of variable frequency control and to point out possible applications in order to create greater awareness of the options available to the engineer as he develops new facilities and improves old ones.

Recent increases in the cost of energy have caused the management and engineering staffs of most companies to evaluate the energy consumption and efficiency of new and existing facilities. Some of the energy conserving equipment which seemed too costly or complex a few short years ago are now becoming the engineer's strongest tool in control of energy consumption.

The Variable Frequency Controller or Inverter, which has the capability of controlling the speed of a standard induction motor, was considered too costly or too complex for many process control applications where more common methods such as eddy current drives, wound rotor motors, hydraulic couplings, throttle valves, etc., could be utilized. Improved technology and cost reduction of the inverter coupled with the increased cost of energy have dramatically altered the value of the inverter drive as a tool to save energy dollars.

WHAT IS AN INVERTER

There are several types of variable frequency controllers available. The burgeoning market for AC motor controllers has spawned many new products. Some of these products have yet to prove themselves in the industrial environment; others have had developmental problems that are yet unsolved. We shall not attempt to make an evaluation of each type of controller in this paper; however, the need for the engineer to evaluate the performance and history of each controller he considers cannot be overemphasized.

For the purpose of our discussion, I have selected the VARIABLE VOLTAGE INPUT (VVI) SIX STEP INVERTER. The VVI inverter has been used successfully for AC motor control for more than ten years. Several manufacturers have developed this type controller or similar variations into extremely reliable industrial duty controllers. These are not unproven devices, although they are new to many industries.

All variable frequency controllers perform basically the same function, that is, they convert fixed frequency sinusoidal AC power to DC, then invert the DC to variable frequency - variable voltage AC power. The output power is constructed from DC pulses; so it is not sinusoidal. The VVI controller is made up of two basic power sections, the DC or rectifier section and the AC or inverter section.

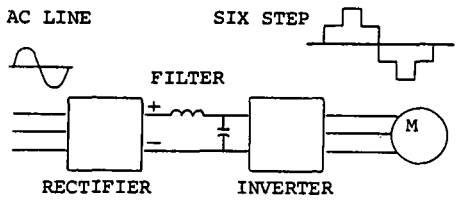


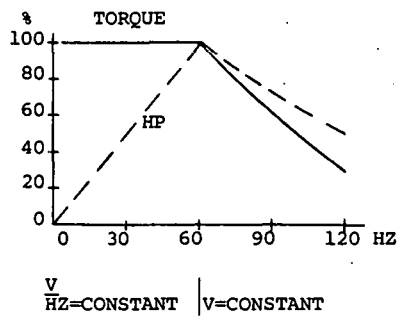
FIG. 1

The VVI inverter gets its name from the variable DC voltage which the rectifier section produces. Variable DC voltage is required in order to produce controlled AC with the volts per hz ratio constant. To operate an AC motor over a speed range from 5-60 hz and still be capable of producing constant torque, the ratio:

$$\frac{\text{Volts}}{\text{hz}} = \text{Constant}$$

must be satisfied. The rectifier and inverter stages work in concert to produce variable voltage, variable frequency AC power. The linear relationship between voltage and frequency is maintained from approximately 5 to 60 hz. Variable frequency controllers can be operated up to 120 hz or higher.

Above 60 hz the voltage is maintained at maximum and the frequency alone is increased. This is referred to as "voltage starved" operation since the volts per hz ratio is not constant. In this mode of operation the available torque and horsepower from the motor fall off as speed increases. A typical speed torque curve for an induction motor operating up to 120 hz is shown below:



MOTOR PERFORMANCE
FIG.2

The DC rectifier section of a VVI inverter is composed of an SCR full wave bridge similar to an SCR controller used for DC motor speed control. After the bridge, the controlled voltage DC passed through a reactor and capacitor network for filtering.

The filtered DC bus is then the power source for the inverter section. Solid state switches, power transistor in lower horsepower controllers and SCR's in larger power units then switch the positive and negative DC bus in the precise sequence to create a step wave AC power source with variable frequency.

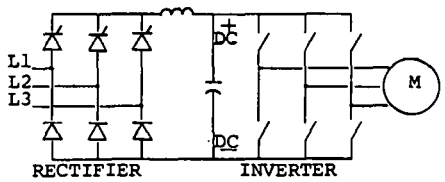


FIG. 3

The inverter switches shown are replaced by SCR's or power transistors in an actual controller.

The regulator required to control the DC section and the firing logic of the inverter section add to the electronic complexity of the controller. On larger horsepower units (typically above 5 HP) the inverter section uses SCR's for switching. Once an SCR is gated "on" it will not turn off until it is reverse biased, or the current drops below a minimum holding current, i.e. the polarity of the applied power is reversed. When an SCR is supplied by AC power the reversing polarity of the AC line automatically reverses the polarity and commutates the SCR off. In the inverter section of variable frequency controllers the SCR's are supplied by a DC bus so the power source does not automatically reverse bias the SCR's. In order to "turn off" or commutate the SCR's, additional circuitry including capacitors and diodes must be added. The capacitors are charged and then discharged across the SCR's at the correct time to cause the SCR's to commutate.

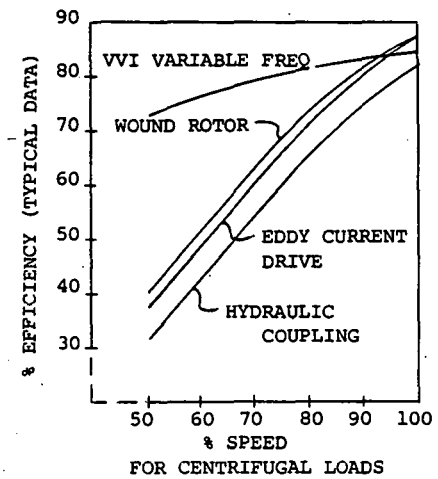
EFFICIENCY

Line to shaft efficiency of a variable frequency AC drive system is dependent upon the losses in the controller and the losses in the motor. Since the efficiency of induction motors changes significantly with load it is necessary to establish the line to shaft efficiency of the system relative to load and speed.

For centrifugal loads like blowers, fans and centrifugal pumps, the torque demand is proportional to the square of the speed. As the speed is reduced, the load drops off quickly. Figure 4 shows a typical line to shaft efficiency curve for a variable frequency controller when applied to a centrifugal load. Figure 5 shows a typical efficiency curve for the controller and motor when applied to a constant torque load; conveyor, positive displacement pump, etc. Figures 4 and 5 include typical efficiency curves for several other types of drives (data is based on commercially available typical performance data) for comparisons.

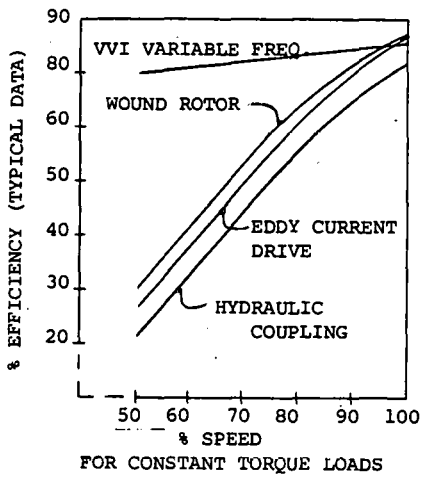
ENERGY COST

In order to determine the energy cost of a variable speed drive system it is necessary to establish both the kilowatt consumption of the drive and the KVA demand costs. Since the system does not operate at fixed speed, these costs must be weighted by the percentage of time that the drive operates at each speed.



FOR CENTRIFUGAL LOADS

FIG. 4



FOR CONSTANT TORQUE LOADS

FIG. 5

A simplified approach to the solution is shown in Table A. The operating costs for several operating speeds are determined on an annual basis, then the total cost is weighted by the percentage of operating time.

The annual power cost at each speed is determined by converting the load horsepower at the desired speed and dividing by the drive efficiency at that speed and load. (see figure 4 and 5)

$$\text{KW LOAD} = \text{HP} \times .746$$

$$\text{KW INPUT} = \frac{\text{KW LOAD}}{\text{EFFICIENCY}}$$

$$\text{ANNUAL KW COST} = \text{KW INPUT} \times 8760 \text{ HRS/YR} \times \$/\text{KWH}$$

The KVA Demand charge also affects the power costs. Power factor data is generally available for most electrical equipment. With the KW input calculated above and the known power factor at the speed and load desired the KVA demand can be calculated.

(A) % OPERATING SPEED	(B) % OPERATING TIME	(C) ANNUAL ENERGY COST AT OPERATING SPEED	(D) WEIGHTED ENERGY COST AT OPERATING SPEED	(E) ANNUAL DEMAND COST AT OPERATING SPEED	(F) WEIGHTED DEMAND COST AT OPERATING SPEED
100	ESTIMATE % OPERATING TIME AT EACH SPEED		BXC = D		EXB = F
90					
80					
70					
60					
50					
OFF		0	0	0	0
			TOTAL D		TOTAL F

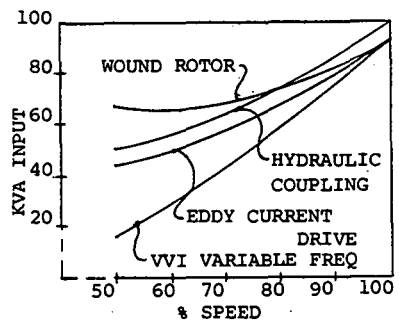
TOTAL ANNUAL ENERGY COST = TOTAL D + TOTAL F

TABLE A

$$\text{KVA DEMAND} = \frac{\text{KW INPUT}}{\text{POWER FACTOR}}$$

DEMAND CHARGE = KVA DEMAND X $/KVA/YR

In order to simplify the calculation Figure 6 shows the demand KVA for several typical 100 HP drive systems operating on a centrifugal load. This chart can be used as a guide for other horsepowers by proportioning the data.



TYPICAL KVA DEMAND FOR 100HP DRIVE ON CENTRIFUGAL LOAD
FIG. 6

With the annual KW and demand charges calculated at several speeds the data can be applied to Table A to determine the total annual operating cost. By making these calculations for each drive or control system under consideration the annual saving can be determined and the payback calculated.

The cost of each system must include the initial investment and the operating cost over its lifetime in order to determine the true cost of the system. Initial cost is no longer the only consideration in specifying control systems.

APPLICATIONS

The applications for variable speed AC drives include installations where variable speed drives have not been used before, as well as replacement of less efficient drive systems. In some cases, maintenance advantage of the AC motor may be sufficient reason for using variable frequency. Consider some of the applications listed.

FLOW CONTROL - Often pumps are run at fixed speeds while flow or pressure is controlled by means of a control valve. The energy lost in the control valve can be eliminated and flow can be controlled by varying motor speed. Depending on flow rates and operating cycles, the cost of the variable frequency controller can often be recovered in a matter of months thereby easily justifying the investment in the variable frequency controller.

FANS & BLOWERS - Flow control is not limited to liquids. A great deal of energy is lost each year in reducing air flow with dampers or by running process changes or ambient conditions would allow slower speeds and less horsepower.

RETROFIT - Replacement of less efficient variable speed control supplies sources of energy saving. Each application requires an operating cost analysis in order to determine if investment in a variable frequency controller is justified, but wherever one of the following drives is in operation close scrutiny of operating cost is warranted:

EDDY CURRENT DRIVE
HYDRAULIC DRIVE
HYDRAULIC COUPLING
WOUND ROTOR MOTOR

ENVIRONMENT & MAINTENANCE - In some drive locations electric variable speed drives have not been used because of environmental or maintenance considerations. Wet or contaminated areas caused severe maintenance problems for DC motors and other electic drives. Volatile atmospheres precluded the use of DC motors or wound rotors motors by requiring extremely expensive enclosures. The AC induction motors are much hardier in these environments and are readily available in explosion proof enclosures at reasonable prices.

CONCLUSION

Variable frequency controllers are valuable energy saving systems. The cost of the controller can often be recovered in a matter of months from energy savings. The initial investment can produce profits at today's energy cost plus increased savings over the life of the system as energy costs rise.

PRACTICAL PROCEDURES FOR AUDITING INDUSTRIAL BOILER PLANTS

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ABSTRACT

Industrial boiler plants are an area of opportunity in virtually every industry to save energy and reduce costs by using relatively simple, inexpensive auditing procedures.

An energy audit consists of inspection, measurement, analysis, and the preparation of recommendations. A complete boiler plant program will consider each individual boiler, boiler room auxiliary equipment, steam distribution and return systems, and steam end use equipment.

This paper summarizes the practical procedures, techniques, and instrumentation which Nabisco uses in its boiler plant energy conservation program.

I am pleased to have the opportunity this morning to share with you some information about an important part of my company's energy conservation program, that part which is concerned with increasing the energy productivity of steam boiler systems.

The Importance of Auditing Boiler Plants

In Nabisco, we focused on boiler fuel because it represents approximately 45% of our total U.S. energy consumption. The significance of this paper, however, is that, as a major energy conservation opportunity, boiler fuel is not of interest only to Nabisco, or even to only the baking industry, but is estimated to be the end use of approximately 20% of the energy consumed by all U.S. industry, excluding electrical power generation.

There are many good reasons for improving the energy efficiency of boiler plants. Here are some of the principal ones: (slide No. 1) First, as already stated, boiler fuel is a significant opportunity to save energy. Second, these are opportunities to also save operating cost dollars, and where capital investment is needed, the benefits usually exceed the minimum corporate hurdle rate of return, particularly if inflation is figured into future years fuel costs. Third, these improvements lend themselves to being implemented quickly, and can be earning a return relatively soon after being identified. Fourth, the availability of scarce fuels is improved by reducing fuel requirements for any given level of production activity. This reason will assume increasing importance for industrial users, most of whom are set up to burn primarily oil or natural gas for boiler fuel, because both of these energy forms are forecast to be in declining natural availability in the year ahead, and government policy increasingly limits industry's access to them. Fifth,

not the least of the advantages is to effect early compliance with probable state conservation regulations dealing specifically with boiler operating efficiency. New Jersey has been something of a bellwether state in this subject, and already has in force regulations requiring combustion efficiency to be kept within tight limits. Percent oxygen must be no more than 1.25 times optimum for the load level; and stack gas temperatures cannot exceed 1.15 times optimum for the load level. Regular readings must be taken, recorded, and retained for five years. This type of regulation, for boilers over approximately 100 HP size, will probably be in effect in all states in the near future. Sixth, and last but not least, most of these improvements are relatively easy for plant and operating personnel to implement.

Audit Procedure

In general, the complete procedure we follow at Nabisco consists of four steps. (slide No. 2). Step one is the audit. I would define audit as meaning performing the necessary inspection, measurement, and evaluation to identify cost effective ways to save energy; documenting them; and presenting written recommendations to operating management which include the appropriate justification to permit prompt decisions. Assuming favorable reception, step two is the implementation of the adjustments, installation of controls, equipment, etc., necessary to achieve the benefits. In some cases, this step will involve third party assistance with the design engineering and with the installation contracting. The third step is operator training, or perhaps retraining, to enable operators to run boiler plants energy efficiently. We believe that this must be a conscious effort, because, in the past, boiler plant operators have usually never had to be overly concerned with energy efficiency and don't understand all the things that they can do to improve it without adversely affecting their traditional responsibilities for safety, reliability, and environmental compliance. Step four is follow-up. Go back after thirty or sixty days to check results, and be available to answer questions and assist with handling exception situations during the period of change.

Briefly, the foregoing outlines the whys and hows of my subject; next I will address the central subject, which is practical procedures for auditing an industrial boiler plant. Purely for purposes of presentation, I have divided the subject under five headings (slide No. 3), but this division and order of mention does not imply any relative importance among the various ideas covered. For any given audit location, relative importance will depend primarily on which conservation opportunities happen to be present. However, there is one exception to this statement, and it is boiler oxygen trim, or minimizing excess air. Experience has taught us that this is most often the largest single opportunity, and so I will discuss it in some detail and, in the interest of time, touch more briefly on the other areas.

Here are the things we audit for each individual boiler (slide No. 4). The purpose of a steam boiler is to make steam by burning in it a fuel, such as oil, natural gas, or coal; and transferring the heat resulting from this combustion process into water, causing it to vaporize into steam. To do this most energy efficiently, we must seek to minimize all of the heat losses associated with boiler's operation, and the audit procedure therefore is concerned principally with the measurement and evaluation of these losses. This slide (slide No. 5) shows schematically where these losses can occur in a representative water tube boiler.

Oxygen Trim, or Minimum Excess Air

As previously mentioned, combustion efficiency is the first, and usually most important, opportunity to audit. The reason is shown on this next slide (Slide No. 6). In the boiler's combustion chamber, a fuel, here methane (the principal constituent of natural gas), which consists of carbon and hydrogen, burns by combining with the oxygen in air, a gas which consists of approximately 21% oxygen and 79% nitrogen. Ideally, we would like to introduce only enough oxygen (air) to combine with the carbon and release all the heat in the fuel. Any more than this theoretical amount is termed excess oxygen (or excess air) and results in energy inefficiency by unnecessarily carrying heat out the boiler stack. However, in practice, it is not possible to operate at zero excess air, in part because of the risk of incomplete combustion which will produce carbon monoxide, a potentially lethal gas; and, when firing oil, will pass through minute unburned carbon particles which will produce a smoke which is too dark to satisfy environmental limitations. For any given boiler, then, the most energy efficient value of excess oxygen, which will also satisfy safety and environmental requirements, can only be determined by testing the boiler in the clean condition over its normal operating load range, usually from one quarter to full load by eighths. At each load point tested, the stack gases are measured for temperature, percent oxygen, percent unburned combustibles, which are assumed to be carbon monoxide. When firing oil, the smoke opacity should also be measured.

Some boiler men prefer to measure carbon dioxide rather than oxygen. The choice has generated a debate which will probably never end. If you run into this in your audit work, the easiest thing to do is measure both and one will serve as a check on the other. Combustion air temperature (boiler room temperature at the combustion air intake) is also recorded.

To tune a boiler to optimum energy efficiency, instruments for measuring these parameters are set up, and the controls are adjusted at each operating point to reduce the amount of air flow relative to the fuel until unburned combustibles, when firing gas, or traces of smoke, when firing oil, are detected. The setting is then relaxed very slightly to provide an operating margin.

To audit a boiler, the same measurements are taken with the boiler adjusted "as found", and the results interpreted by comparison to that boiler's optimum values, if known, or to generally accepted efficient values. When auditing, if unburned combustibles in excess of 0.05% or a trace of smoke are detected, the air should be increased immediately until the limit is not exceeded. Normally, the excess air is too high and this condition is not encountered. When it is not present, the difference of the two temperatures and the percent oxygen (or percent carbon dioxide) are in a fixed relationship to percent excess air and boiler combustion efficiency. These values are best obtained in a field audit by using tables, specific to the fuel being burned, which are illustrated in this slide (Slide No. 7).

Rule of thumb, a well designed boiler, efficiently operated, will approach excess air values of 10% firing natural gas, or 12% or 15% firing #2 or #6 oil respectively. If the audit reveals higher values, an opportunity probably exists to improve efficiency by cleaning and tuning the boiler. In the final analysis, however, optimum efficient values of excess air vary from one boiler to another, due to design, age, condition, etc., and an accurate determination can only be made by testing.

This next slide, (Slide No. 8) shows how these instruments are arranged, and these slides (Slides Nos. 9 and 10) show an actual installation. The instruments shown are accurate, portable, and cost less than

$3,000. They include: a Teledyne model 980 analyzer for oxygen and unburned combustibles; Omega model 2166A digital thermometer with high temperature probe and thermocouple leads; Bacharach model RCC-B smoke tester, and Bacharach monoxor carbon monoxide indicator.

You should be aware that similar equipment is available from several manufacturers, and Nabisco's use of this particular equipment does not imply any judgement of competitive makes and models.

When the actual boiler efficiency has been determined from the measurements and tables, and an optimum efficiency is assumed using the excess air percentages previously mentioned, an idea of the annual dollar savings possible can be calculated quickly by using the percent efficiency improvement as the percent reduction in fuel consumption and cost. In most cases the writer has seen, this can easily justify the control repairs, adjustments, and even upgrade or replacement that are necessary to operate at optimum efficiency.

Blowdown Control

The subject of boiler water treatment is extremely broad and complex, and will be approached in this paper only as it relates to saving energy. It should be mentioned that one of the continuing reasons for boiler water treatment is energy related, and is to prevent scale build up which retards heat transfer and can cause equipment to operate less efficiently. We deal with the total subject by an arrangement with a major water treatment company which permits us to buy from them a complete reverification of a locations program as if the location were a new customer. This is a highly specialized service and not one that should be attempted in-house.

However, there are certain procedures that are inherent in water treatment programs which can and should be audited. The first of these, for each individual boiler, is blowdown. Look for evidence that the blowdown is controlled. Required rates will vary, and variations from as little as 2% to as much as 10% are not uncommon. But, any unnecessary blowdown wastes BTU's and increases the cost of the treatment chemicals.

For boilers under approximately 30,000 lbs. per hour rating, we consider the use of interval timer control on the top blow to control dissolved solids. These units cost about $1,000.00 per boiler installed and consistantly minimize blowdown losses by automatically keeping the dissolved solids' concentration very near the control range upper limit. On systems with moderate to high make up percentages, they should be cost-effective.

More frequently, the bottom or mud drum blow down for settlable solids is uncontrolled. If necessary, piping should be arranged to permit the operator to dip a sample from the blow down at the end of a timed blow, into a cylindrical breaker graduated into one hundred parts. After cooling and settlement, the solids settle-out should not exceed one one-hundredth, or the blow time should be gradually increased until this concentration is reached. Less settlement will permit reducing the blow time. Obviously, this control involves negligible equipment cost and should be standard procedure in all attended boiler plants. Some idea of the savings involved can be had from the rule of thumb that a saving of 3% in blow down is approximately equal to 1% of fuel consumption.

When blowdown has been minimized, the resulting blowdown rates should be reviewed for installation of flash tanks vented into the feed water and for the routing of the liquid flowed to sewer through a heat exchanger with the make up water. Well over 75% of the blowdown energy can be recovered in this manner.

Stack Heat Recovery

If the boiler is clean, the excess air in trim, and the exit flue gas temperature is sufficiently above the sulfurous acid dew point of about 325°F, stack waste heat recovery units should be explored. As a rough rule of thumb, in a combustion air preheater, a 40°F increase in combustion air temperature produces a 1% reduction in fuel consumption. For a feed water heater, raising the water temperature 10°F will create the same benefit. Installation costs vary with local circumstances, but can be as much as $100,000.

It is unusual to be able to justify this recovery in a boiler operating below 100 psig drum pressure. The stack gas temperature leaving the boiler (the "exit flue gas temperature") in a clean, trimmed boiler should normally be in the range of 50 to 150 degrees F higher than the drum steam temperature in a well designed unit. Typically, the New Jersey code permits a rise of 1.15 time optimum from clean to dirty condition, or for a boiler with 100 psig saturated steam in the drum, about 1.15 x (100 + 338)°F = 503°F exit flue gas temperature, too near the acid dew point to justify heat recovery.

Other Audit Considerations - Individual Boilers

Consider means to raise the combustion air temperature by using the hot air from the ceiling of the boiler room. Increasing the combustion air temperature by 40°F raises boiler efficiency by approximately 1%.

Check for infiltration through casing leaks by blowing smoke at the suspected leak and observing if it is drawn into the firebox by looking through the peepholes. This is not always possible to do, but, where leaks are detected, they can usually be closed inexpensively with high temperature cement.

When firing heavy oil, it is important to maintain the viscosity of the oil entering the burner within the range for which the burner is designed to operate efficiently. This slide (slide No. 11) shows a Louis C. Eitgen Co. "falling ball" type visgage, which costs about $120. It can be employed to insure that the temperature for which the burner heater is set is, in fact, producing the correct viscosity. Accurate readings can be obtained quickly and easily.

Finally, for each individual boiler, visually inspect the design, condition, and adjustment of the boiler combustion controls. Find out when they were last adjusted, and if the operators have "found it necessary" to readjust them since. At today's fuel costs, most boilers can justify the cost of good automatic combustion control systems and of the maintenance and adjustment. If the boiler is burning over $125,000 per year value of fuel, automatic oxygen trim equipment utilizing a stack oxygen sensor is usually justifiable.

Operating Practices

This next slide (slide No. 12) lists three boiler room operating practices which should be reviewed in an audit. The second and third are self explanatory, but the first deserves some comment because it is rarely adhered to.

Any plant with more than one boiler and varying load conditions, whether by shift, week or season, should always seek to have the most efficient boiler or combination of boilers on line to supply the load. More often, boilers are operated to equalize the operating hours among them, or because their individual efficiencies at different load levels are not known. Even boilers built to the same specifications will usually not have identical load vs. efficiency curves, especially after they have been in service for a few years. The energy audit should develop or recommend development of an actual load vs. efficiency curve for each

boiler, and the conscious determination of the most efficient combination to meet the various load conditions encountered. Demonstrating the cost savings between this practice and any other present practice will usually be sufficient to motivate its adoption by the plant operators.

Distribution & Return System Considerations

This next slide (slide No. 13) lists energy audit considerations in the steam distribution and return systems.

First is the perennial subject of steam trap maintenance. No matter what the plant maintenance supervisor claims, steam traps should be surveyed for blow-through and for misapplications. We do this by paying a "factory-trained" representative of one of the nationally known trap manufacturers to check all the traps, tag those needing attention, and provide a written report of the parts needed, their cost, and the estimated annual savings based on our cost of steam. The price of the survey is credited in full against any parts ordered. So far, among many plants handled this way, we have only failed once to get our survey money back, and pay back periods have usually been well under one year.

Similarly, pipe insulation manufacturers should be invited to survey the insulation on all piping and heated vessels with surface temperatures above 100°F. There are usually numerous cost effective opportunities to insulate fittings, repair damaged insulation, and extend insulation to applications not previously thought to be worthwhile.

Returning again to water treatment, this time by equipment serving the system, always check for the presence of a water softener in the make-up water supply. External softening, frequently coupled with alkalinity control, is usually more economical than internal treatment; and an analysis should be requested from the location's water treatment service to establish the cost benefit.

Additionally, examine the deaerating arrangement for proper operation and for the opportunity to raise its pressure. Increasing the pressure to 15 psig raises the temperature close to 250°F and substantially reduces oxygen solubility, saving on subsequent chemical treatment and minimizing the chance of oxygen corrosion.

Steam End Use Conservation

This slide (slide No. 14) lists end use conservation possibilities. Always keep in mind that every BTU saved at an end use location means approximately one and one-half BTU's of boiler fuel saved, due to the multiplier effect of system losses.

The easiest end use consideration to review is the system pressure requirement. A reduction of approximately 75 psi to the boiler steam pressure will raise the boiler efficiency 1%.

Check the percent condensate returns in the system. This is readily done with a formula which uses chloride readings of make up, feed water, and condensate returns. The percent returns should be recorded for future comparison, as they will usually vary seasonally. Look for opportunities to increase the percent returns.

One end use that deserves particular mention is steam used in the heating, ventilating, air conditioning units. Large savings can often be made by rebalancing the air flows, replacing outside air damper seals, reducing ventilation air to minimum, installing economy cycle control logic, perhaps reducing humidity control and reheat, and duty cycling multiple unit systems during off peak periods.

One final thought. Look for chances to reclaim heat from equipment unrelated to the steam plant, for example, using air compressor jacket cooling water for boiler make up.

In closing, I hope that this presentation has made you all aware that steam boiler systems present a major opportunity for energy conservation, and that it has given you an understanding of practical methods that exist to locate and evaluate them.

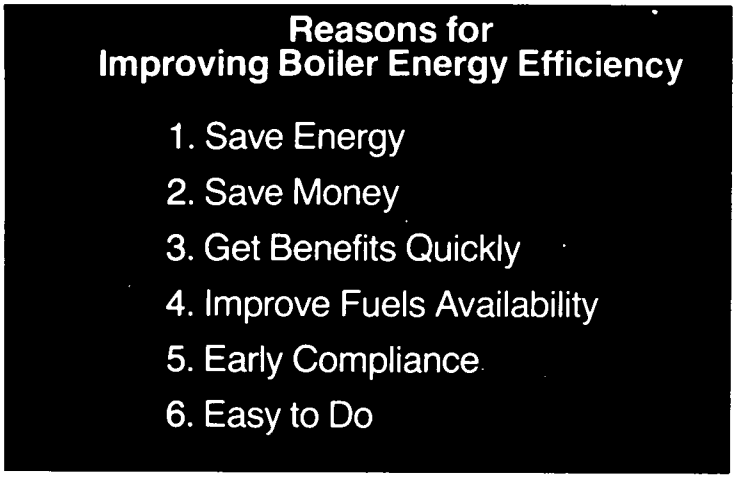


FIGURE 1

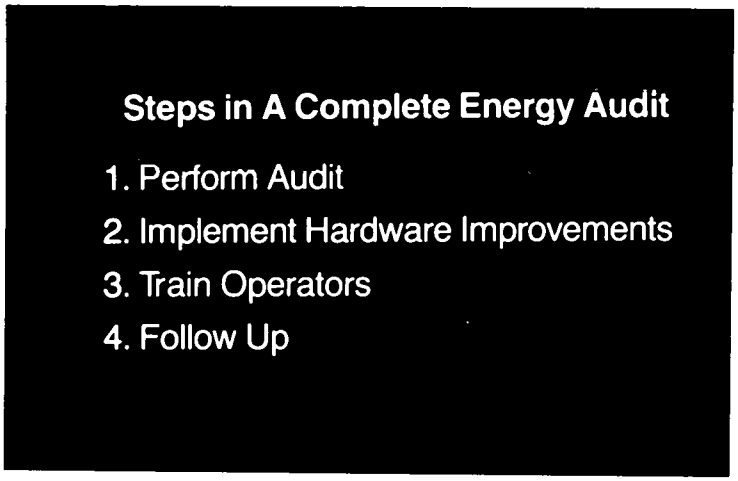


FIGURE 2

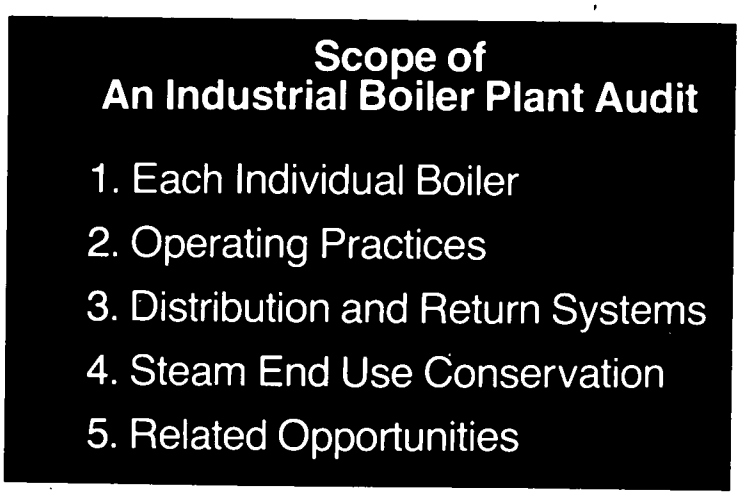


FIGURE 3

Individual Boiler Audit Considerations

1. Combustion Efficiency
2. Blowdown
3. Stack Heat Recovery
4. Combustion Air Temperature
5. Infiltration
6. Oil Viscosity Control
7. Controls Condition and Adjustment
8. Soot Blowing

FIGURE 4

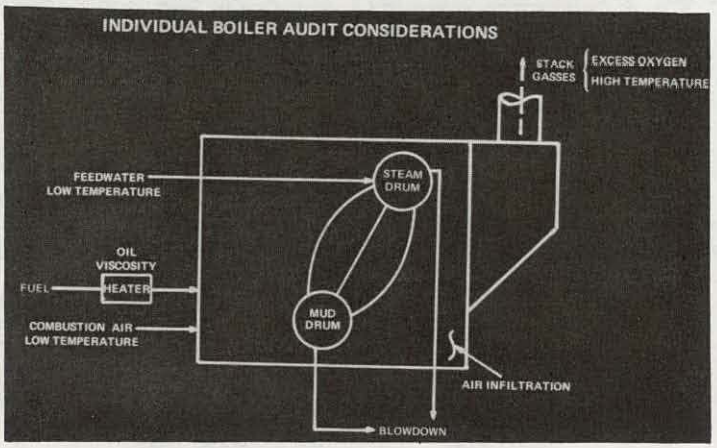


FIGURE 5

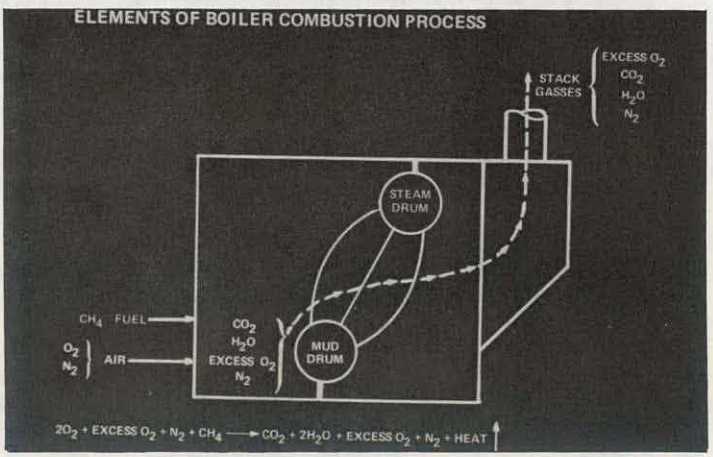


FIGURE 6

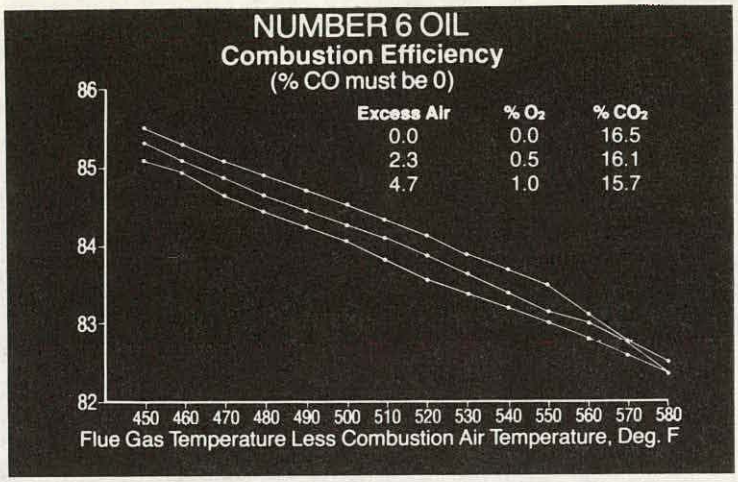


FIGURE 7

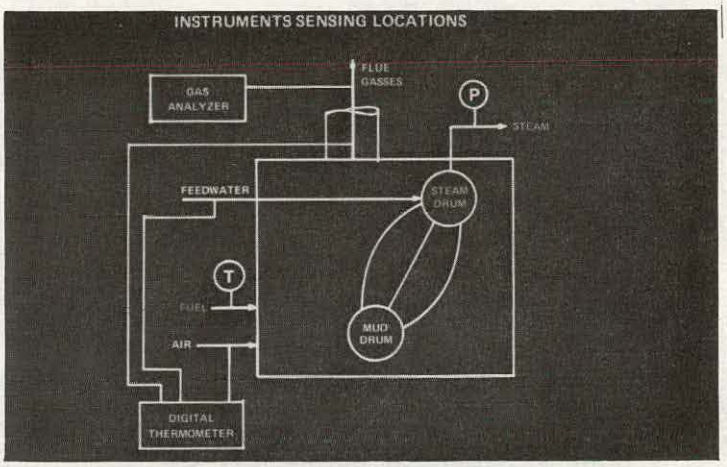


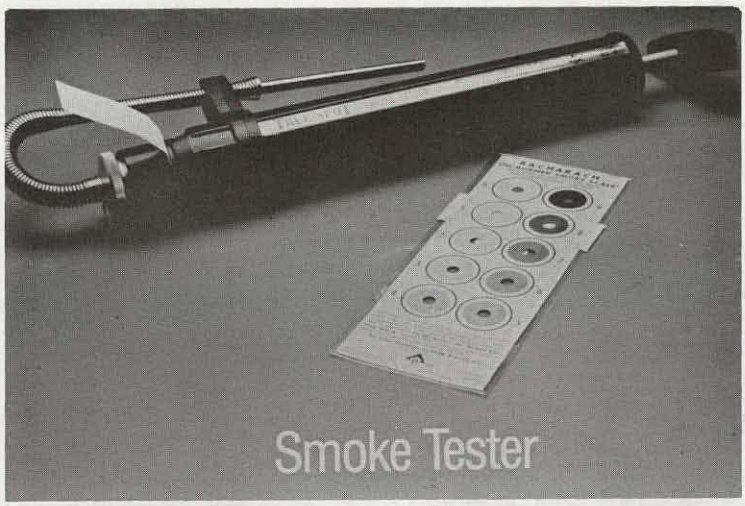
FIGURE 8



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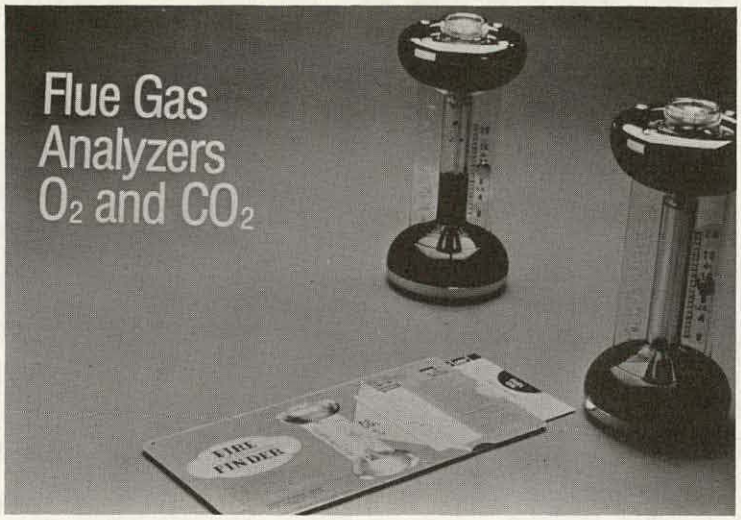
FIGURE 9 a


CHANNEL
TEMP
PULSE
OMEGA
Digital Thermometer


Smoke Tester


CO Indicator
555

FIGURE 9 d



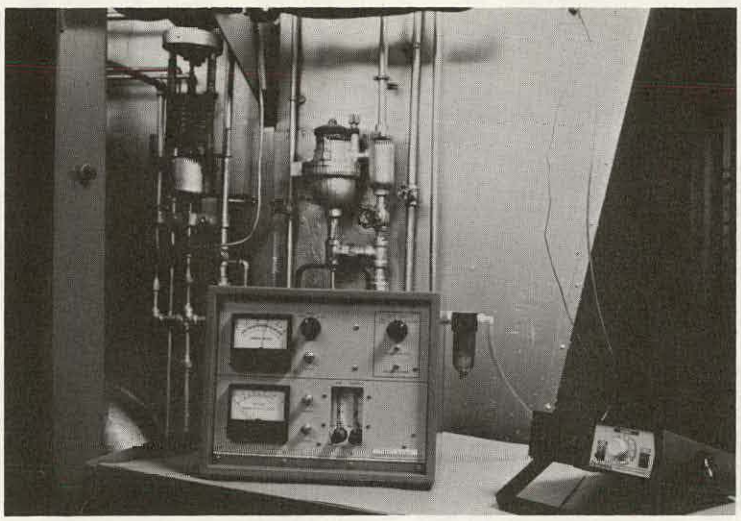




FIGURE 10 b



FIGURE 11

Operating Practices Audit Considerations

1. Load Management
2. Regular Testing and Recording
3. Periodic Inspection and Maintenance

FIGURE 12

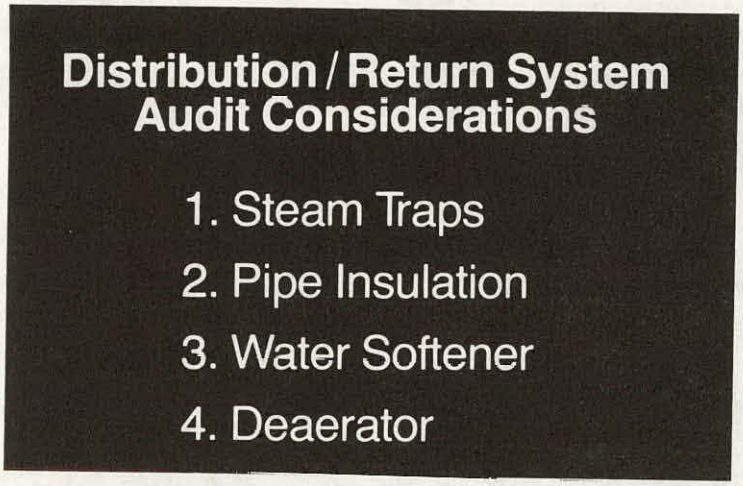


FIGURE 13

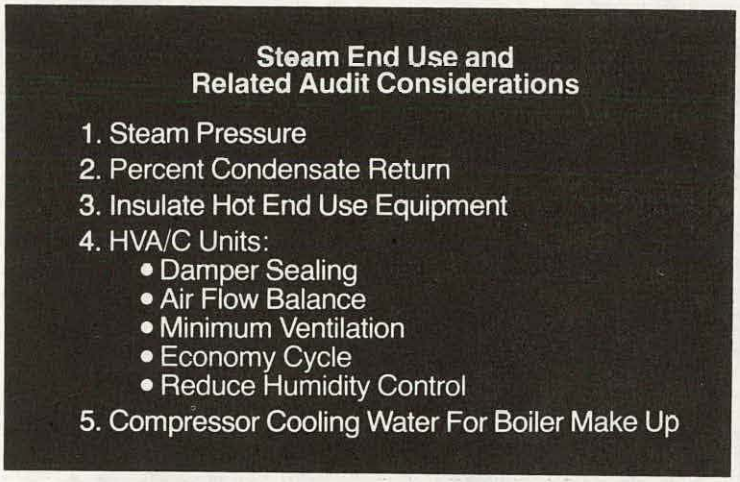


FIGURE 14

COMBUSTION AIR PREHEAT SHOULD BE MORE THAN SIMPLY RECYCLING ENERGY

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ABSTRACT

Combustion air preheat can and should result in fuel savinga far in excess of the energy added to the combustion air. In a typical installation of air preheat on a fired tubular reactor, the addition of 2.5 million BTU/hr to the combusion air results in a fuel savings of 6.8 million BTU/hr. Control of excess effects of excess combustion air on radiant heat transfer in a fired tubular reactor, the point at which air preheat does become simply recycling energy, and the point at which any advantage of air preheat is lost entirely. How air preheat and excess air influence radiant heat transfer is discussed and a calculation method presented which can be used to develop justification for improved excess air control.

INTRODUCTION

A popular misconception regarding combustion air preheat applied to fired tubular reactors is that the energy added to the combustion air simply replaces its equivalent amount of fuel energy. Unfortunately, this can be the case, but it should not be. For example, with a typical application of combustion air preheat on a fired tubular reactor the addition of 2.5 million BTU/hr to the combustion air results in a fuel savings of 6.8 million purchased BTU/hr.

This paper shows how this is possible, points out when air preheat may become just recycling BTU's, and presents a calculation method suitable for use in developing justification for improved combustion air control.

RADIATIVE HEAT TRANSFER

Lobo and Evans {1} and Mekler and Fairall {2} present excellent discussions of radiative heat transfer inside fired heaters. They derive a pair of equations which, when used together, explains why combustion air preheat is more than simply recycling energy.

Reference {1} shows that, by making certain assumptions,

$$\frac{Q_R}{\alpha A_{cp}\emptyset} = 0.173\left[\left(\frac{T_R}{100}\right)^4 - \left(\frac{T_T}{100}\right)^4\right] + 7\,(T_R - T_T). \qquad (1)$$

For fired heaters,

T_T = the average radiant coil tube wall temperature, °R

$\alpha A_{cp}\emptyset$ = the "effective" heat transfer surface of the radiant coil

T_R = the "equilibrium" or "radiant plane" temperature (ignoring wall losses, convective heat transfer, and air leakage, T_R should be the "bridgewall" temperature, or the temperature of the flue gas leaving the radiant section), °R

$7\,(T_R - T_T)$ = heat transferred to the radiant coil by convection.

For this paper the convective heat transfer term will be ignored and T_R will be assumed to be the "bridgewall temperature.

Reference {2} shows the amount of heat absorbed in the radiant zone must equal the heat given up by the flue gas in dropping from the adiabatic flame temperature, T_F, of the combustion process to the "bridgewall" temperature, T_R.

$$Q_R = WT_FC_{pf} - WT_RC_{pr} = \sum_1^4 W_cC_{pc}\,(T_F - T_R) \qquad (2)$$

By combining Equations (1) and (2) and dropping the convective heat transfer term,

$$\frac{Q_R}{\alpha A_{cp}\emptyset} = \frac{\sum_1^4 W_cC_{pc}\,(T_F - T_R)}{\alpha A_{cp}\emptyset} = 0.173\left[\left(\frac{T_R}{100}\right)^4 - \left(\frac{T_T}{100}\right)^4\right] \qquad (3)$$

we have a relationship expressing radiant heat transfer in terms of the major variables excess air and air preheat effect; i.e., the adiabatic flame temperature, T_F, and the overall exchange factor, $\emptyset$. $\emptyset$ is affected because flame emissivity is affected.

BASE CASE CALCULATION

Now, let's look at an application of Equation (3) to a fired tubular reactor operating without air preheat at the conditions shown below:

Radiant Process Duty (Q_R)	=	11,100,000 BTU/Hr.
Bridgewall Temperature (T_R)	=	2050°F = 2510°R
Fuel Rate	=	1350 Lbs./Hr. of Pure Methane
Excess Air	=	20 Mol %
Combustion Air Temperature	=	77°F
Effective Tube Surface (αA_{cp})	=	516 Ft.^{2} (Set by Furnace Design)
Flame Emissivity (P_f)	=	0.415
Overall Exchange Factor ($\emptyset$)	=	0.620
Effective Heat Transfer Surface ($\alpha A_{cp}\emptyset$)	=	320 Ft.^{2}
Adiabatic Flame Temperature (T_F)	=	3170°F (See Table I)
Average Tube Wall Temperature (T_T)	=	1645°F

We have the information needed to solve all three terms in Equation (3). The solution should yield an identity. Using the above information and the appropriate values from Tables I through V, we get,

$$\frac{Q_R}{\alpha A_{cp}\emptyset} = \frac{11,100,000}{320} =$$

34,688 BTU/Hr./Ft.^{2} of Effective Heat Transfer Area

Also,

$$0.173\left[\left(\frac{T_R}{100}\right)^4 - \left(\frac{T_T}{100}\right)^4\right] = 0.173\left[\left(\frac{2510}{100}\right)^4 - \left(\frac{2105}{100}\right)^4\right]$$

= 34,699 BTU/Hr./Ft.^{2} of Effective Area

Furthermore, from Tables I, III, and IV,

$$\sum_1^4 W_c C_{pc} (T_F - T_R) =$$

$$(1350)\left[2.75\frac{CO_2}{(0.321)}(3170 - 2050) + 2.25\frac{H_2O}{(0.641)}(1120) + 0.8\frac{O_2}{(0.277)}(1120) + 15.8\frac{N_2}{(0.303)}(1120)\right]$$

= 11,089,000 BTU/Hr.

$$\frac{11,089,000}{\alpha A_{cp}\emptyset} = \frac{11,089,000}{320} = 34,653 \text{ BTU/Hr./Ft.}^2 \text{ of Effective Area}$$

These are reasonable checks, so the calculation does yield an identity.

BASE CASE WITH 520°F AIR PREHEAT

Now let's retrofit the above heater for combustion air preheat to operate with an air temperature of 520°F and at 20% excess air. Furnace radiant section design and excess air have not changed from the base case, therefore αA_{cp}, $\emptyset$, and $\alpha A_{cp}\emptyset$ have not changed. Due to air preheat, however, T_F is now 3470°F, rather than 3170°F (Table I).

This is a fired tubular reactor, thus we do not want to change the radiant section process duty, nor do we want to change T_T appreciably since tube metallurgy is not to be changed. Because of convection section metallurgy the "bridgewall" temperature should not change.

Therefore,

$$\frac{Q_R}{\alpha A_{cp}\emptyset} = \frac{11,100,000}{320} = 34,688 \text{ BTU/Hr./Ft.}^2 \text{ of Effective Area}$$

If we now let "y" = the total pounds of fuel required to get the $Q_R/\alpha A_{cp}\emptyset$ needed, then, using Equation (3),

$$\frac{y(3470 - 2050)\left[2.75\ (0.323) + 2.25\ (0.648) + 0.8\ (0.278) + 15.8\ (0.303)\right]}{320}$$

= 34,688 BTU/Hr./Ft.^{2}

$$\frac{(1420)\ (7.356)y}{320} = 34,688 \text{ BTU/Hr./Ft.}^2$$

y = 1063 Lbs./Hr. Fuel = Lbs./Hr. Fuel Required at 520°F Air Preheat and 20% Excess Air

Solving the third term in Equation (3) for the average tube wall temperature we get 1645°F, the same value as without air preheat. Therefore, for this base case, if we apply air preheat at 520°F and 20% excess air, we attain a fuel savings of:

$$\frac{(1350 - 1063) \times 100}{1350} \quad \text{or} \quad 21.23 \text{ Wt. \%}$$
(6,171,074 Net BTU/Hr.)

Under these preheat conditions, the air involved with the combustion process contains only (21.6) (1063) (108.76) = 2,497,200 BTU/Hr. (see Tables IV and V). Thus, by recycling only 2.5 million BTU/hr., we reduce fuel consumption in the radiant section by 6.2 million NHV BTU/hr. (6.85 million BTU/hr., GHV) and still transfer the same amount of radiant heat. Of course, since total flue gas flow to the convection section is reduced, additional surface is needed in that section to obtain the required heat transfer in it.

Using Equation (3), the calculation method shown above, and the data given in Tables I through V, the effects of excess air on radiative heat transfer on the fired tubular reactor described above were evaluated. The results are shown in Table VI. In all cases the radiant process duty, Q_R, is 11,100,000 BTU/hr. and the "bridgewall" temperature, T_R, is 2050°F.

TABLE I

Approximate Adiabatic Flame Temperatures (T_F) for Pure Methane, °F

Air Temperature, °F	Mol % Excess Air			
	20	30	40	50
77	3170	2980	2820	2680
520	3470	3290	3130	2970

TABLE II

Variation of P_f, $\emptyset$, & $\alpha A_{cp}\emptyset$ with Excess Air (αA_{cp} = 516 Ft.^{2})

% Excess Air	P_f	$\emptyset$	$\alpha A_{cp}\emptyset$, Ft.^{2}
20	0.415	0.620	320
30	0.400	0.605	312
40	0.385	0.585	302
50	0.370	0.570	294

TABLE III

Mean Heat Capacity of Flue Gas Constituents Between Adiabatic Flame Temperature, T_F, and Bridgewall Temperature, T_R (2050°F), BTU/Lb/°F

Mol % Excess Air	Combustion Air Temp., °F	Flue Gas Component			
		CO_2	H_2O	O_2	N_2
20	77	0.321	0.641	0.277	0.303
20	520	0.323	0.648	0.278	0.304
30	520	0.322	0.644	0.278	0.303
40	520	0.321	0.639	0.277	0.302
50	520	0.320	0.635	0.276	0.301

TABLE IV

Flue Gas Composition When Burning Pure Methane at Various Excess Air Levels (Air Humidity Ignored)

Mol % Excess Air	Lbs. in Flue Gas Per Lb. of Methane Fired				
	CO_2	H_2O	O_2	N_2	Total
20	2.75	2.25	0.80	15.80	21.60
30	2.75	2.25	1.20	17.12	23.32
40	2.75	2.25	1.60	18.43	25.03
50	2.75	2.25	2.00	19.75	26.75

TABLE V

Heat Content of Dry Air Above 77°F, BTU/Lb.

Temperature, °F	BTU/Lb.
77	0
200	29.64
300	54.06
400	78.75
475	97.46
520	108.76

TABLE VI

Effects of Excess Air on Fuel Usage When Using Combustion Air Preheat at 520°F

Case No.	1*	2	3	4	5
Excess Air, Mol %	20	20	30	40	50
Air Temperature, °F	77	520	520	520	520
Adiabatic Flame Temperature, °F (T_F)	3170	3470	3290	3130	2970
Flame Emissivity (P_f)	0.415	0.415	0.400	0.385	0.370
Exchange Factor (Ø)	0.620	0.620	0.605	0.585	0.570
αA_{cp}Ø, Ft.^{2}	320	320	312	302	294
Average Tubewall Temperature, °F (T_T)	1645	1645	1631	1616	1600
Fuel Required, Lbs./Hr.	1350	1063	1140	1234	1370
Fuel Savings:					
Lbs./Hr.	0	287	210	116	-20
M BTU/Hr. (NHV)	0	6.17	4.52	2.49	-0.43
M BTU/Hr. (GHV)	0	6.85	5.01	2.77	-0.48
BTU in Combustion Air, M BTU/Hr.	0	2.50	2.77	3.23	3.63

* Base Case

αA_{cp} for all cases = 516 Ft.^{2}

Fuel for all cases is pure methane.

M = 1 x 10^6

Figure 1 shows clearly that at approximately 49% excess air any fuel savings achieved by the addition of air preheat has been lost.

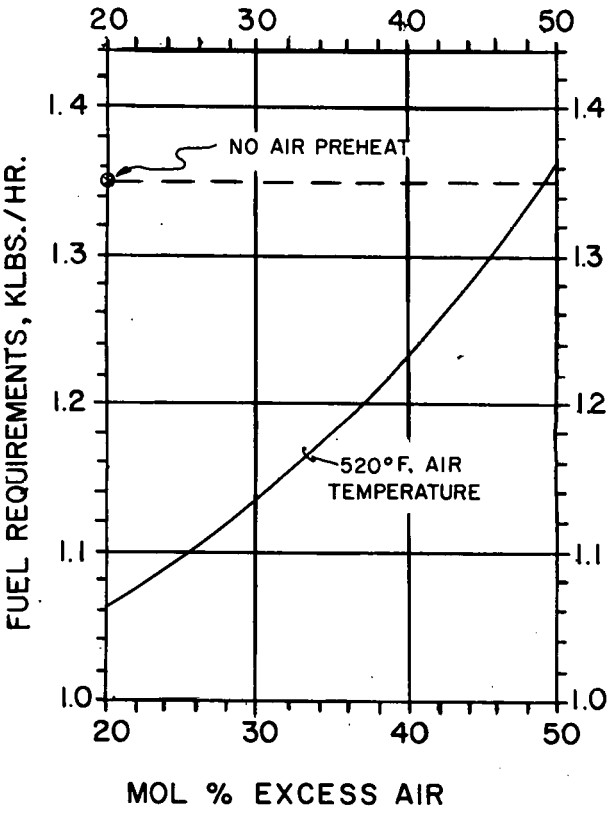


FIGURE 1

Effect of Excess Air on Fuel Requirements with 520°F Air Temperature

(Base Case - Case No. 1 of Table VI)

Figure 2 shows that, for this example, at approximately 38% excess combustion air, air preheat does become a matter of simply recycling energy since the amount of fuel reduction equals the energy in the preheated combustion air.

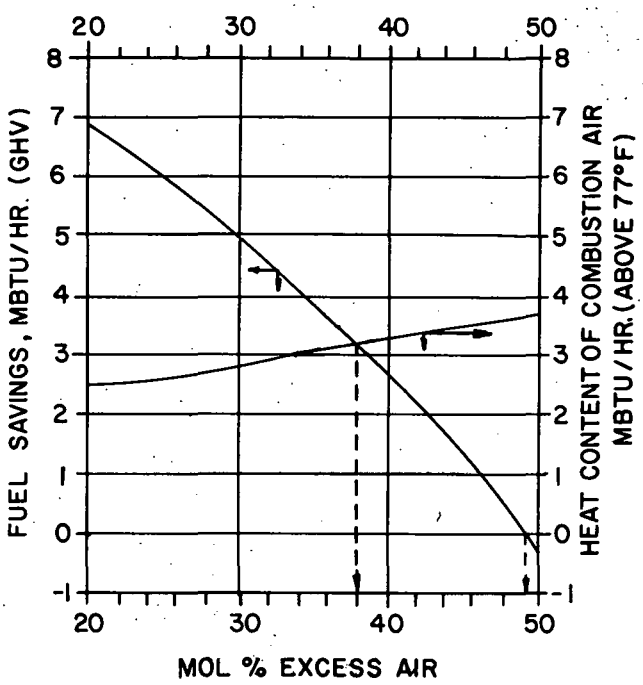


FIGURE 2

Variation of Fuel Savings and Heat Content of Combustion Air with Excess Air

(Air Temperature = 520°F)

(Base Case = Case No. 1 of Table VI)

To prevent any misinterpretation of these data, it must be pointed out that the application of combustion air preheat does not increase the sensitivity of fuel requirements to control of excess air. In fact, as Table VII shows, combustion air preheat decreases the sensitivity of fuel consumption to excess air. Even at 50% excess air and 520°F air temperature, fuel usage is not as high as it would be at 30% excess air without air preheat.

TABLE VII

Comparison of Fuel Consumption at Various Levels of Excess Air at Two Levels of Air Temperature

Combustion Air Temperature, °F	77°F				520°F			
Excess Air, Mol %	20*	30	40	50	20	30	40	50
Fuel Required, Lbs./Hr.	1350	1531	1744	2016	1063	1140	1234	1370
Fuel Usage, Lbs./Hr.**	0	+181	+394	+666	-287	-210	-116	+20

* Base Case

** From Base Case

Retrofitting a fired tubular reactor with combustion air preheat requires a considerable capital investment. Good quality excess air control is required to obtain maximum return on that investment. For direct fuel savings, however, excess air control is even more important for those units operating without air preheat.

In summary, I have attempted to:

(1) Present a calculation method for evaluating radiative heat transfer that should be applicable to any fired tubular reactor and can be used to develop justification for improved excess air control on these heaters. Data used in the calculation must reflect the particular furnace design, fuel gas composition, air temperature, and process duty for the heater being investigated.

(2) Show that combustion air can and should be more than simply recycling energy.

(3) Illustrate that, through its effect on adiabatic flame temperature and flame emissivity, uncontrolled excess air can seriously limit the fuel savings obtained by application of combustion air preheat.

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NOMENCLATURE:

A_{cp}	$Ft.^2$	- The "cold plane" area of the radiant coil; i.e., the area of a plane surface of equivalent height and length as the radiant coil.
C_{pc}	BTU/Lb.°F	- Average specific heat of flue gas components between T_F and T_R. (See subscripts below.)
C_{pf}	BTU/Lb.°F	- Specific heat of flue gas at T_F.
C_{pr}	BTU/Lb.°F	- Specific heat of flue gas at T_R.
GHV	BTU/Lb.	- Gross heating value of fuel.
NHV	BTU/Lb.	- Net heating value of fuel.
Q_R	BTU/Hr.	- Radiant section process duty.
T_F	°F	- Adiabatic flame temperature.
T_R	°R	- Temperature of the hot radiation source.
T_T	°R	- Temperature of the heat absorbing surface.
W	Lbs./Hr.	- Total flue gas flow rate.
W_c	Lbs./Hr.	- Flow rate of each flue gas component. (See subscripts below.)

SUBSCRIPTS:

1 = Carbon Dioxide
2 = Water
3 = Oxygen
4 = Nitrogen

GREEK LETTERS:

α - Effectiveness Factor (Function of Radiant Coil Configuration)
ϕ - Overall Radiant Heat Transfer Exchange Factor

CONSTANTS:

0.173 Stefan-Boltzmann Radiation Constant

FLUE-GAS CONDITIONING TO REDUCE PARTICULATE EMISSIONS IN INDUSTRIAL COAL-FIRED BOILERS

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ABSTRACT

Chemical technology has been used successfully to solve many of the operational and emissions problems that result from burning coal. This paper describes the use of blended chemical flue gas conditioners to significantly reduce particulate emissions in coal-fired industrial boilers. In many cases, these chemical conditioning agents have increased the efficiency of electrostatic precipitators and mechanical collectors by more than fifty percent. The effectiveness of this technology has been demonstrated on units generating 50,000 to 200,000 lbs./hr. steam. Results achieved at various industrial plants under actual operating conditions are presented.

INTRODUCTION

Today, we are burning over 650,000 tons per year (TPY) of coal to generate steam for process, heating, and electricity. Coal is re-emerging as the dominant fuel for steam generation for the next twenty years; in fact, it is planned that coal use could double in the 1985-90 period. The reasons for this increase in coal-burning activity include:

(1) The escalating costs and uncertain availability of fuel oil
(2) The natural gas shortage and priority given to residential users
(3) The national goal of energy independence

However, as coal burning increases to meet energy coals, policy-makers are faced with a dilemma: coal combustion releases more atmospheric pollutants, especially SO_2 and particulates.

Although there had been considerable air pollution control legislation prior to 1970, the Environmental Protection Agency (EPA) was not created until the Clean Air Act of 1970. Not only did the 1970 law create the EPA as a separate agency reporting directly to the President, but it established schedules and a regulatory mechanism to treat air quality on a national basis. Although the initial reaction to this law by coal burners was the switch to fuel oil, the events of the next decade brought many users back to coal. The 1977 Clean Air Act went further to establish air quality standards and also begin to force steam generators to burn coal instead of fuel oil. Thus, federal, state, and local environmental protective agencies have become increasingly involved with the development and enforcement of air pollution quality regulations.

Recent state and federal rule changes demand higher efficiency removal of fly ash in older and new coal-burning units. The trend has been to burn low sulfur (less than 1.0%) coal at the expense of higher sulfur coal in order to meet the SO_2 regulations. The majority of coal-burning boilers use mechanical collectors (e.g. cyclones) and electrostatic precipitators (ESP) units as the primary means of particulate collection. Mechanical collector efficiency is influenced by coal ash composition and content, gas volume, and inlet velocity. ESP unit efficiency is influenced by the above factors, but it is also significantly affected by the SO_3 content in the flue gas (which is primarily affected by the sulfur content). The fly ash of low sulfur coal is more difficult to collect because the low SO_3 content of the flue gas limits the ESP power available to capture the fly ash. Thus, the concern that burning high sulfur coal releases unacceptable levels of SO_2 has been replaced with the concern that low sulfur coal burning results in higher particulate emissions.

During the past several years, there has been an increased interest in the use of chemical conditioning for the enhancement of mechanical collector and ESP unit efficiency. Generally, the goal has been to meet particulate compliance without the need for large capital outlays and long lead times. Modification of particle size distribution and reduced re-entrainment through cohesive forces had led to improved cyclone efficiencies. Lowering the resistivity by adsorbing minute quantities of polar substances from blended chemical formulations onto the fly ash particles has worked to bring many ESP units back to design efficiencies.

The subject matter of this paper is to provide a review of industrial coal burning steam generators and collection devices. Also, the fly ash properties that affect collection efficiency are discussed as well as the reasons for collector performance changes. Chemical conditioning will also be discussed in detail as well as the energy savings (economics) that can be realized. Case studies are presented which illustrate the benefits of chemical conditioning on the efficiency enhancement of ESP and cyclone units.

BACKGROUND

A. Coal Burning Boilers

Industrial coal-fired boilers can be classified according to the method of firing as follows: 1) suspension (pulverized coal); 2) mass burning (underfeed, travelling grate, and vibrating grate stokers; and 3) combination suspension and mass (spreader stoker). Although coal type, furnace geometry, combustion control, and operating parameters (excess air leakage, furnace temperature, etc.) affect emissions, the firing method has the most significant effect on the particulates generated.(1)

A brief description of the firing methods, their limitations, and the recommended gas cleaning devices follows:

1. Suspension. In pulverized coal (P-C) boilers, coal is pulverized to talcum powder fineness and is then blown into the furnace where it burns in suspension. The burner mixes the (primary) air/pulverized coal mixture with additional (secondary) air in the correct proportions and delivers the mixture to the furnace for combustion. P-C boilers are usually limited (economically) to steam generation of at least 100,000 lbs./hr. They are selected for their high steam generating capacity and quick response to steam demands. The ash content of the flue gas is easily calculated for pulverized coal. With P-C firing, depending on the coal ash deposition characteristics, the entrained ash in the flue gas may vary from 60% to 80% of the total ash. Also, the carbon contained in flue gas from P-C firing is less than 2% of the total fly ash. The particle size distribution of the fly ash is usually 50% finer than 20 microns. Electrostatic precipitators (ESP) and bag filters are used for particulate removal.

2. Mass Burning

   a. Underfeed Stokers. Raw coal is pushed under a bed of hot ash and burning coal. As it is pushed upward through hotter zones, it goes through the various phases of combustion. Underfeed stokers had been limited to loads of 30,000-100,000 lbs./hr. steam; with the advent of multiple retort firing, steam generations of 500,000 lbs./hr. were realized. Due to high maintenance costs, smoking at low loads, limitation to load fluctuations, underfeed stokers have lost market share in recent years. Very little ash is entrained in the flue gas; thus, mechanical collectors are generally sufficient to meet particulate compliance.

   b. Travelling Grate Stokers. A bed of coal is laid down on top of a moving grate which moves it through the furnace to the ash pit. The burning coal bed is penetrated by air which is introduced beneath the grates and overfire air to realize efficient combustion. These stokers are practically limited to about 100,000 lbs./hr. steam although they have capability to 400,000 lbs./hr. Preference for low volatile fuels (anthracite, lignite, coke breeze, and solid refuse), non-caking coals as well as slow response to load changes limits the travelling grate stoker capabilities. However, they have minimal fly ash carryover and can operate at low loads without smoking. Cyclones are used to collect particulate matter.

   c. Vibrating Grate Stokers. Vibrating grate stokers are similar to travelling grates except that vibrating grates feed coal to the furnace. These stokers usually operate in the same steam rating range (100,000-400,000 lbs./hr.) as travelling grate units. Fly ash emissions are slightly higher than travelling grates due to the additional agitation of the vibrating rate. However, cyclone collectors are sufficiently efficient in general use to meet particulate requirements.

3. Combination Suspension and Mass Burning

Spreader stokers combine the features of suspension firing like P-C boilers and mass burning like grate firing boilers. Coal is introduced to the furnace through a feeder which consists of a flow regulating device and a rotor that distributes the coal into the furnace. Some of the coal is burned in suspension, and some falls to the grate where it is burned. Spreader stokers are utilized in the 75,000-400,000 lbs./hr. steam rating range. A wide variety of coals from Eastern bituminous to lignite can be burned. Spreader stokers are extremely sensitive to load fluctuations. Due to the suspension firing, there is a high amount (greater than 40%) of ash carryover. Cyclone collectors with reinjection of coarse carbon-bearing particles followed by ESP units are utilized for efficient particulate collection and combustion.

B. Particulate Emissions from Coal Combustion

Emissions from coal-fired boilers vary considerably depending upon the coal used and the type of firing. The ash content, particle size, moisture and sulfur content in the combustion products are the significant factors that dictate the use of and affect the design of collection equipment. It is quite difficult to arrive at average size distributions for different methods of firing coal, since much depends on the fuel preparation, excess air used, firing rate, and furnace design. Although a wide variety of equipment is available for particulate emission control from stationary combustion sources, particulates are usually controlled by mechanical collectors, electrostatic precipitators (ESP), bag filters, or scrubbers. In this article, only mechanical collectors and ESP units are discussed since these units are most often used with industrial boilers.

1. Mechanical Collectors. The mechanical collector of primary interest in today's environment is the high efficiency multiple cyclone, which is shown in Figure 1. However, another mechanical collector design is discussed in some detail in the Case Study Section. The advantages of the cyclone's mechanical collector are 1) simple and reliable, 2) no moving parts, 3) low capital cost, 4) compact, and 5) low maintenance. The disadvantages are 1) particle size limitation (cyclones ineffective in 5 micron and smaller capture) 2) irregular flow patterns caused by internals erosion, 3) gas circulation in common ash hopper causes reentrainment, and 4) reduced efficiency at lower loads.

2. Electrostatic Precipitators. The electrostatic precipitator is a very efficient collection device (Figure 2) which operates on a simple principle. Fly ash is statically charged, accelerated to a collecting plate, and rapped off into a hopper. Precipitator advantages are: 1) flexible (high) efficiency design, 2) broad range of particulate concentration, 3) low draft loss, 4) high reliability, and 5) low maintenance. Some disadvantages are as follows: 1) high capital cost, 2) efficiency losses due to reentrainment, 3) sensitivity to dust resistivity, 4) field or model flow studies required, and 5) difficulty in meeting opacity requirements.

1. Motivations. There are several motivations for improving the performance of an existing fly ash collection system. The most common reason is that regulatory authorities have determined that particulate emissions exceed legal limits and so emissions must be reduced to avoid fines. Also, state or federal regulations may become more stringent so that a unit which had been complying with prior standards may be forced to reduce emissions further. Another situation likely to become more common is that coal-designed units which switched to oil in the early 1970's may reconvert to coal. The old collection devices built to the standards prevailing in the 1960's may not be able to attain the stricter standards of the 1980's. Another reason for increasing percentage collection efficiency is to increase coal procurement options. A more efficient collector will allow companies to burn higher ash (less expensive) coal and continue to meet mass emissions standards. Also, under the EPA's new Bubble Policy[2], a reduction in particulate from one source may be used to offset increases in emissions from other sources. A highly efficient col-

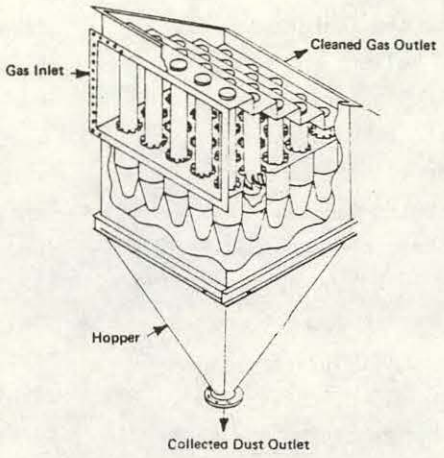


Figure 1. Multiple Cyclone Collector

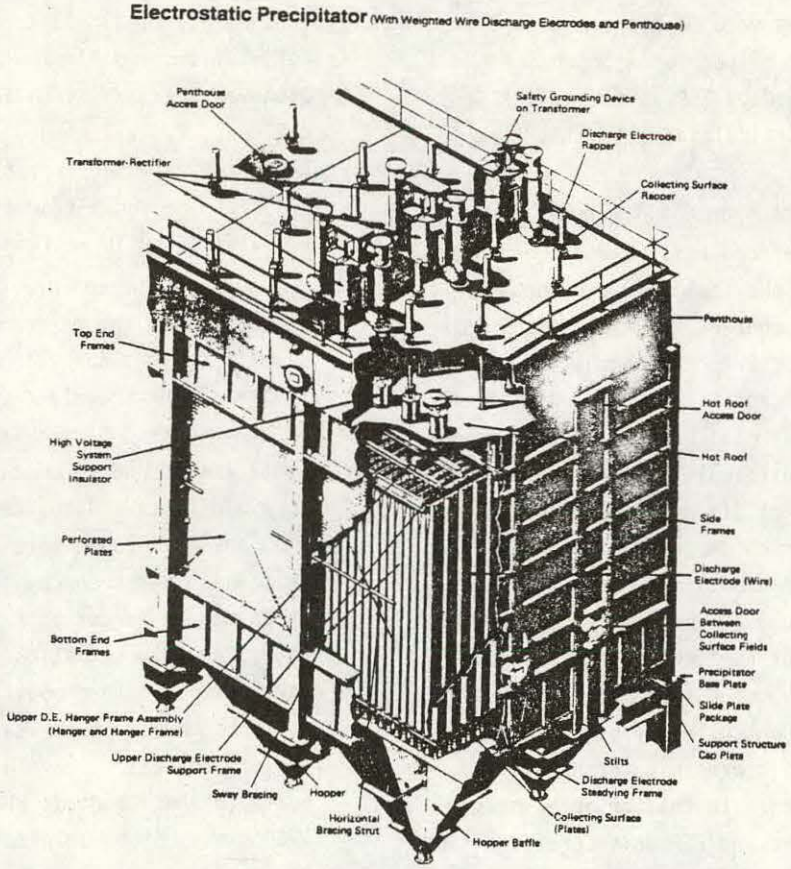


Figure 2. Electrostatic Precipitator

lection system on one large boiler in a plant may allow other boilers to burn less expensive coals and avoid new pollution control hardware costs.

B. Mechanical Collectors

Multiple cyclones are the most common fly ash collectors for industrial boilers. In operatio the dust-laden flue gas enters a common inlet

then turns downward to enter the individual (multiple) cyclones (usually 3-18 in. diameter). The gas spirals downward with the inertia of the particles (dust) carrying them to the cylinder walls, and the clean gas exits from the cyclone center's nozzle. The important parameters of cyclone performance are:

1) Particle size. The efficiency of mechanical collectors is directly related to the particle size distribution. Efficiency declines below 20u; even the best cyclones collect few particles below 5u.

2) Gas flow distribution[3]. A balanced air flow is needed for optimum performance. An uneven flow pattern caused by leakage pluggage of improper location of inlet vanes can cause eddy currents, decreased efficiency, and reentrainment.

3) Velocity/pressure drop. Efficiency increases with velocity up to a practical limit of about 5000 fpm. In general, a one-inch increase in pressure drop will boost efficiency by 20%.

4) Grain loading. Small tubes (3 inches or less) will become plugged if the loading exceeds 100 gr/ft.^{3} while single cyclones can handle up to 500 gr/ft.^{3}.

The first step towards improved performance is to repair any leaks in the cyclone bank or the ductwork. Other obstructions to a balanced air flow, for example, accumulated ash deposits or dented tubes, should be removed or replaced. Another possibility for increasing performance is to block off a section of the tubes to increase the pressure drop. However, care must be taken to ensure that grain loadings are not excessive or that air flow becomes badly imbalanced. Another proven method of increasing efficiency is to inject chemical conditioning agents into the gas stream. Chemicals have been used to agglomerate the finer fly ash particles, thereby increasing efficiency. Also, the fly ash becomes more cohesive, reducing reentrainment.

C. Electrostatic Precipitators

Electrostatic precipitators (ESP's) are devices used to electrically charge flue dust and cause these charged particles to migrate toward collection surfaces by an induced electrical field. The flue dust held on the collecting electrodes by a combination of electrical, molecular (van der Wahls), and mechanical forces, is removed by rapping the electrodes to impart an acceleration to dislodge the dust into a hopper for removal.

The major determinants of efficiency are[4]:

1) Resistivity. The influence of resistivity on the collecting ability of electrostatic precipitators is more easily understood if considered in terms of the reciprocal concept, conductivity. Conductivity is a measure of the ability of a material to carry an electrical current. In the context of ESP operation, conductivity is a measure of the time that charge can flow around and between particles (surface conductivity) or through the particles (bulk or volume conductivity). If the particles are too conductive, the charge will quickly flow to the grounded plate, and the uncharged particles will be reentrained. If the particles are not conductive enough (i.e. if the resistivity is too high), then the charge flows too slowly and charged particles are held on the collecting plate by strong electrical forces. A thick dust layer forms on the plate, the effective collecting voltage drops, and collection efficiency declines. In extreme cases, stresses in the accumulated dust layer cause localized breakdowns which release positive ions of "back corona". (Figure 3)

Resistivity is a function of:

a) Chemical composition of fly ash[5]. Surface resistivity is a function of the lithium, sodium, iron, and potassium content of the fly ash.

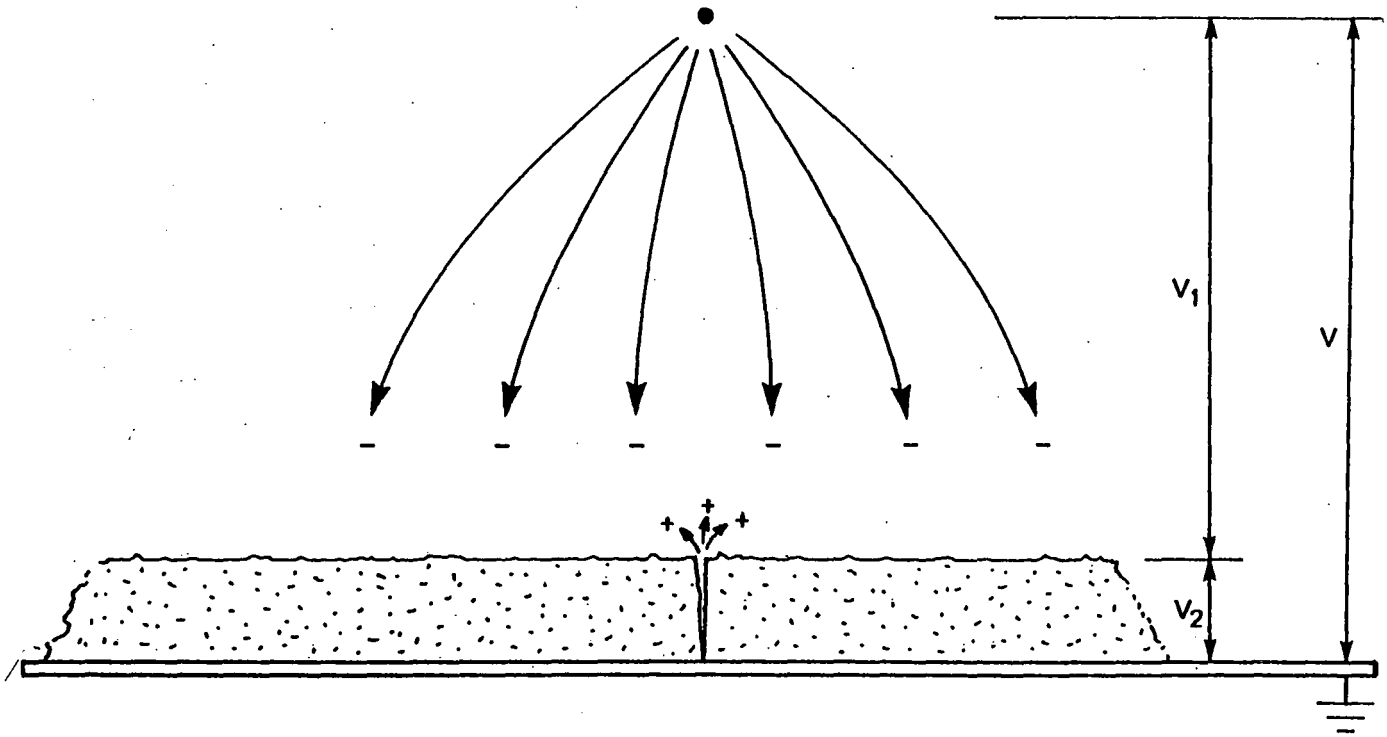


Figure 3. Back Corona Effect

b) Moisture. Water vapor provides a conductive medium for charge to flow to the plate. The higher the moisture content of the flue gas, the lower the resistivity.

c) Temperature. Figure 4 shows the influence of temperature on resistivity. Below 200^0C, surface effects dominate resistivity. As the temperature increases, surface liquids are vaporized and resistivity is determined by the charge carried through the particles. As temperature continues to increase, the molecules within the particle become more excited and more likely to carry charge, so resistivity decreases.

d) SO_3. H_2SO_4 provides a highly conductive ionic solution. High sulfur (above 3%S) coals usually have low resistivity fly ash and low sulfur coals (less than 1%S) may create very high resistivity fly ash.

2) Gas flow rate. ESP efficiency is inversely proportional to the gas velocity.

3) Gas velocity distribution. Non-uniform gas flow can cause reentrainment of collected particles; and poor distribution may reduce the spark-over voltage in the inlet field, limiting power and efficiency.

4) Gas temperature and composition. Temperature effects particle resistivity as mentioned above. Also, temperature effects velocity and viscosity of the flue gas. Excursions below the acid dew point will increase ESP corrosion.

5) Particle size. Smaller particles (below 5u) are harder to collect and more easily reentrained.

6) Boiler operation. Variations in boiler operation cause changes in ESP parameters. For example, combustion will create carbonaceous, low resistivity fly ash that is easily reentrained; high excess air levels will generate high levels of SO_3.

7) Rapping. Improper frequency or intensity of rapping can cause reentrainment or, con-

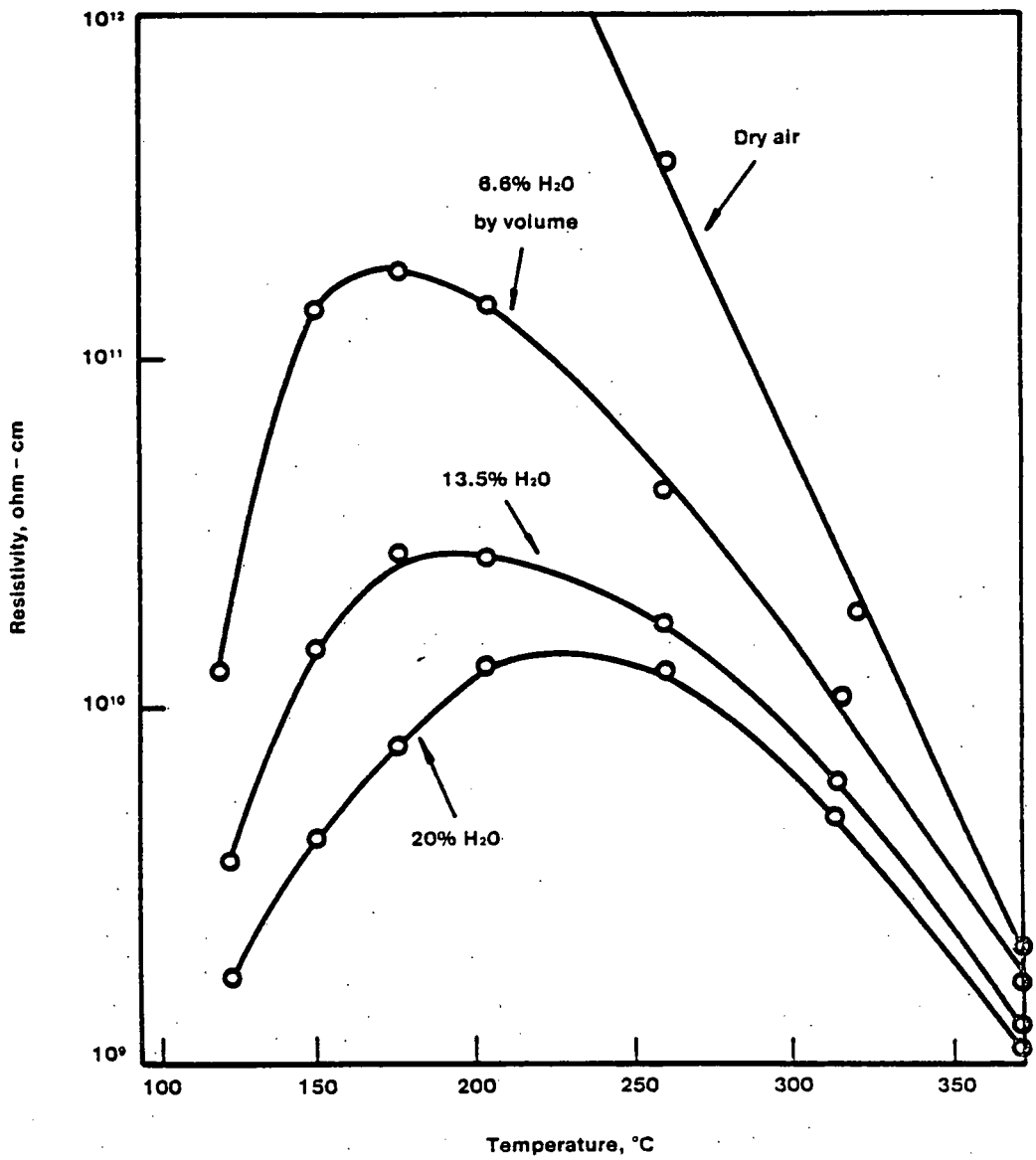


Figure 4. Fly Ash Resistivity vs. Temperature

versely, an excessive buildup of dust on the collection plates.

8) ESP operating condition. Obviously, broken wires, corroded plates, or faulty T/R sets will hurt performance.

Diagnosing the causes of precipitator performance at less than design efficiency requires careful analysis. The most important goal is to maintain the maximum possible power input to the precipitator. Often, the reason for low ESP power is related to resistivity problems; however, an initial problem definition study can help pinpoint the problem. The initial study should include: gas temperature and velocity profiles, air leakage measurements, an internal inspection of the ESP, careful observation of ESP controls to determine spark rate and voltage drop during sparking, in-situ resistivity measurements, rapper on-off observations, and a review of records to investigate the relationship of boiler operation to ESP operation. This short study should indicate electromechanical repairs or improvements that might increase efficiency. For example, repositioning turning vanes, removing ash deposits, re-aligning ESP plates, changing the rapping cycle, or patching

leaky ductwork.

However, if a general resistivity problem or a serious reentrainment problem exists, electromechanical fixes probably won't be sufficient. Chemical conditioning agents have been used successfully to correct these problems, as the next section will discuss.

CHEMICAL CONDITIONING

Various chemical treatments have been successfully used to enhance collector efficiency, especially with ESP units [6]. The primary efforts have centered on reducing high particulate resistivity in ESP units through use of sulfur trioxide, ammonia, and recently blended chemical formulations. However, when space charge, agglomeration, or cohesiveness is the major mechanism of inadequate collection efficiency, some approaches have been ineffective, and, until recently, chemical formulations had not been used to enhance mechanical collector efficiency. One approach has been to oxidize inexpensive sulfur to generate SO_3, which is known to lower fly ash resistivity[7]. Most of these systems, however, are elaborate mechanical/chemical systems requiring large capital outlays. Also, not all fly ashes respond consistently to this treatment; there is little evidence in the literature that indicates long-term continuous successful SO_3 conditioning. This is probably due to the fact that SO_3 has no effect on space charge, agglomeration, or cohesiveness. Because of the hazard of increased dew point and the potential of condensation and corrosion, SO_3 is generally injected into the flue gas stream after the air preheater. In many cases, this does not permit sufficient time for SO_3 distribution and absorption on the fly ash before it reaches the ESP. The result can be undesirable particulate and SO_3 (blue haze) emissions--possibly leading to acid fallout.

Ammonia has also been used to try to condition fly ash to improve collection efficiency [8]. There is little documented evidence of the consistency of ammonia conditioning. Any effect is probably attributable to increased electrical space charge which can substantially raise ESP operating voltages. The resulting higher field would account for the increased collection efficiencies reported. Increased cohesiveness of fly ash particles lowering reentrainment has also been postulated with ammonia treatment. Because of possible adverse reactions such as ammonium bisulfate formation, ammonia is also generally applied after the air preheater,seriously limiting the distribution and reaction time before the ESP.

With the switch to low sulfur coal and the varied and somewhat uncertain coal supplies, the need for a more universally effective chemical conditioning was needed. Also, treatment for mechanical collectors and hot side ESP units was needed and sulfur trioxide and ammonia systems were not applicable. A blended chemical conditioning formulation operates by the following mechanism:

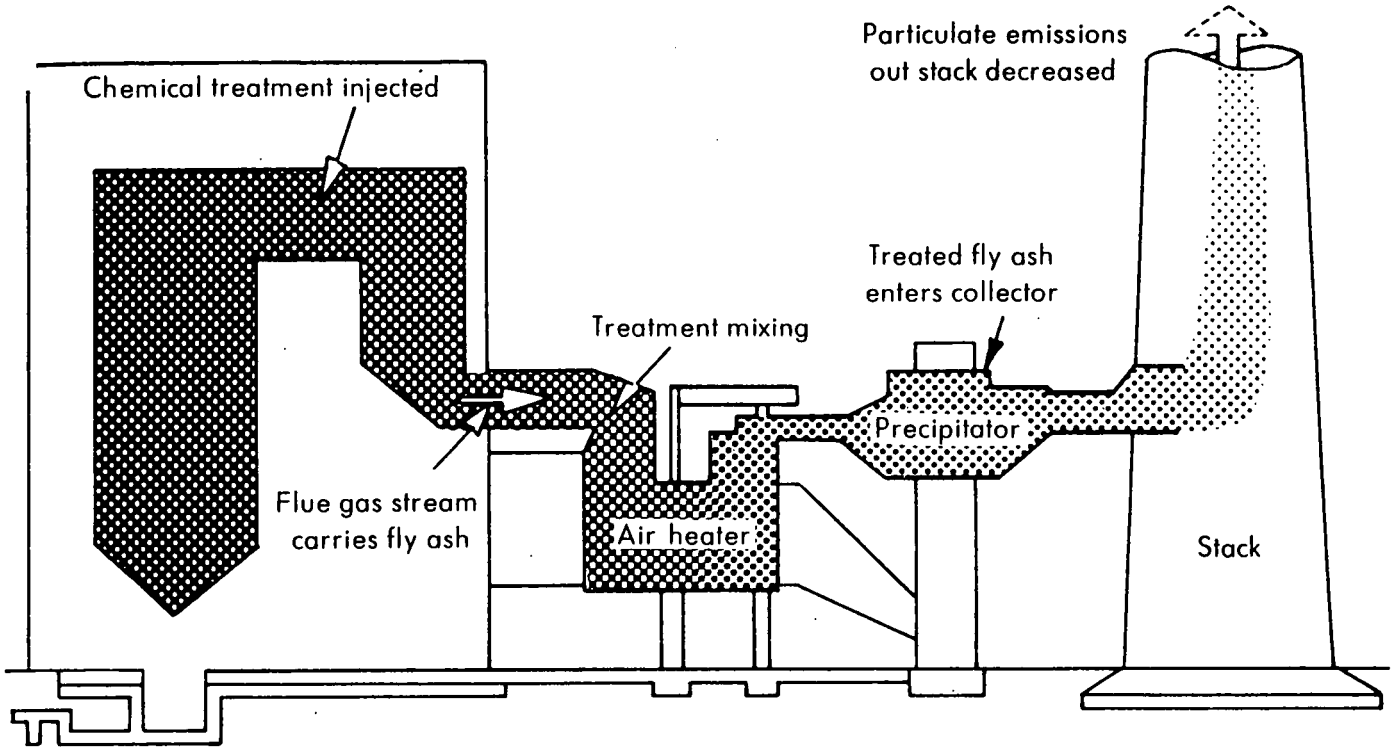
1. A change in the surface conductivity of the fly ash to a more favorable value by adsorption of some conductive species on the surface of the fly ash particle. Since chemical conditioning of the fly ash alters its resistivity by means of a surface coating absorbed onto the dust particles, the resistivity of the treated ash approaches a final value that does not depend on the resistivity of the untreated particle.

2. A space-charge effect which occurs by molecular fragmentation on injection to gaseous products which can combine at the lower temperatures at the air preheater or before the ESP. It is believed that the chemical fragments in the corona field fills in the space between the dust particles, having a homogenizing effect which decreases sparkover and allows the use of higher applied voltages.

3. The third mechanism is a combination of particle size increase by agglomeration into a range where the ESP or mechanical collector is more effective and improved cohesiveness of the fly particles in which reentrainment into the flue gas stream is reduced.

By combining the chemicals which can give rise to these mechanisms, a more universal and consistent chemical conditioning system can be developed. Chemical treatment can be injected into the "hot" (1000-1500^{o}F) zone as shown in Figure 5, or the

APOLLO FLY ASH CONDITIONING SYSTEM



Chemical is injected into stack gas prior to the air heater to improve the characteristics of the fly ash and thereby improve particulate collection by the electrostatic precipitator or mechanical collector.

U.S. PATENT NO. 4,070,162 APOLLO CHEMICAL CORP., WHIPPANY, N.J. 07981

Figure 5. Flue Gas Conditioning Injection

cold (250-500^{o}F) zone or with mechanical collectors or hot side ESP units (with ESP before air preheater).

ECONOMICS

The savings that can be attributed to the use of flue gas conditioning can be summerized into three distinct areas which include: 1) lower cost coal; 2) elimination of higher priced fossil fuel; and 3) lowering capital expense for mechanical systems.

Flue gas conditioning will permit the burning of lower quality coal which is less expensive, but contains more ash. As the coal ash content increases, the collection device (ESP or cyclone) becomes inadequate to meet compliance due to grain loading increases. However, by increasing the efficiency of the collector, flue gas conditioning will enable the system to maintain emissions levels despite the higher inlet loading. Also, since the amount of chemical treatment is independent of the coal sulfur content, it allows flexibility in meeting emission restrictions, if regulations should change in the future. Thus, a savings of $10/ton of coal or more can be realized by the use of chemical conditioning which can cost as little as $1.00/ton. A plant that uses 100,000 TPY of coal can realize an annual savings of $1,000,000 or more.

In many cases, oil or gas is either co-fired or alternately fired with coal in order to meet compliance regulations, or another gas or oil-fired boiler is required to be put on-line as the coal-fired boiler has its load decreased in order to meet compliance. In order to illustrate the savings from eliminating oil--coal at $48/ton costs $2.00 per million BTU's (12,000 BTU/lb. coal) and #6 fuel oil costs $4.44 per million BTU's (at $28/bbl.) thus, coal can save $2.44 per million BTU's or an average industrial user can save about $1,000,000

per year ($2.44/$10^6$ BTU X 50 X 10^6 BTU X 8000 hours = $976,000).

Mechanical systems (cyclones, ESP units, baghouses, and scrubbers) are usually the initial choice to retrofit a collection device which is not meeting particulate compliance. This initial reaction can be quite costly to a company that does not take flue gas conditioning into consideration. Figure 6 demonstrates that a savings of over $400,000/year can be realized by selected FGC to bring a unit into compliance instead of a mechanical system. Also, FGC can be installed within weeks of initial approval required for most mechanical systems. Also, new ESP units can be reduced significantly in size and cost by using FGC to reduce specific collection area (SCA). For example, it has been indicated [9] that a company was able to reduce its SCA from 688 sq. ft./1000acfm to 279 sq. ft. per 1000 acfm by designing FGC into the system--realizing a savings of over 50%, or a $5,000,000 ESP units now costs about $2,500,000. Thus, the use of FGC can produce savings to the industrial coal-fired boiler in the multimillion dollar range.

Figure 6

COMPARISON OF FGC WITH MECHANICAL SYSTEMS

Unit Size	400,000 PPH (Steam)
Coal HV	12,300 BTU/lb.
Coal Use, Maximum	22 TPH
FGC Treatment	0.20 GPT
Operating Time	7000 hours

	FGC System	Mechanical Systems @ $3500/MMPH	Mechanical Systems @ $6000/MPPH
Capital Investment (Installed)	$ 50,000	$1,400,000	$2,400,000
Annual Fixed Charges (@ 18%)	7,500	252,000	432,000
Annual Variable Costs[a]	130,000	70,000[b]	120,000[b]
Total Annual Costs	$137,500	$ 322,000	$ 552,000

[a] Includes maintenance
[b] At 5% of investment

CASE HISTORIES

The following case histories present examples of successful applications of chemical flue gas conditioning with ESP's and mechanical collectors on industrial boilers.

No. 1 - An integrated steel mill had been burning 2.2%S, 17% ash coal on 5-175,000 lb./hr. boilers with cyclones and ESP's. The collection system could not achieve compliance; swinging loads on all five boilers, high levels of unburned carbon and unsatisfactory ESP controls compounded the problem. The severity of the environmental problems threatened to cause the premature closing of the boiler house.

However, the boiler house was able to attain compliance through electrical, mechanical, and chemical modifications recommended by Apollo Technologies. Improved instrumentation helped control ESP spark rates. Steam generation and distribution procedures were changed so that only one boiler varied load and the others were kept stable. And when FLUETROL 40, a chemical conditioning agent, was injected into the flue gas stream, ESP powers increased by 20-100% on the five units. Because of increased agglomeration and cohesion of the fly ash, the rapping cycle was altered to maintain cleaner collecting plates with minimum reentrainment. The net result was that particulate emissions were decreased by 50% and the boiler house was able to achieve compliance.

No. 2 - A specialty chemical plant required process steam from a 65,000 lb./hr. boiler burning 8% ash, 12,200 BTU/lb. coal. The unusual mechanical collection device (Figure 7) could not achieve the compliance limit of 0.2 lbs./MMBTU. An initial study showed that mechanical modifications to the collector were necessary. Reducing the spinner angle and increasing the vane length sharply improved collection efficiency; however, the boiler could not yet meet compliance.

Chemical conditioning agents were initiated to agglomerate the fly ash, making the particles easier to collect. When FLUETROL 54 was injected at 2 gallons/hr., emissions were reduced to 0.17 lb./MMBTU and the boiler was certified in compliance by government officials.

No. 3 - A chemical plant was faced with heavy fines for excess particulate emissions. The ESP's on six boilers rated at 100,000-205,000 lbs./hr. of steam were not meeting the strict compliance limit of 0.1 lb./MMBTU. An Apollo flue gas conditioning system was quickly installed and chemical feed was started at 0.15 gal./ton of coal. The results were dramatic: ESP powers more than doubled and emissions were reduced by 65-90%. All six boilers were certified in compliance.

CONCLUSIONS

As coal usage for steam generation in the industrial sector increases, there will be greater interest in innovative, low-cost ways of controlling fly ash emissions. Chemical flue gas conditioning offers a proven method of improving the performance of collection systems so that industrial coal users can:

- Burn lower cost, high ash coals without violating compliance limits.
- Limit expenditures for new pollution control hardware.
- Substitute coal for higher priced fuel oil and gas.

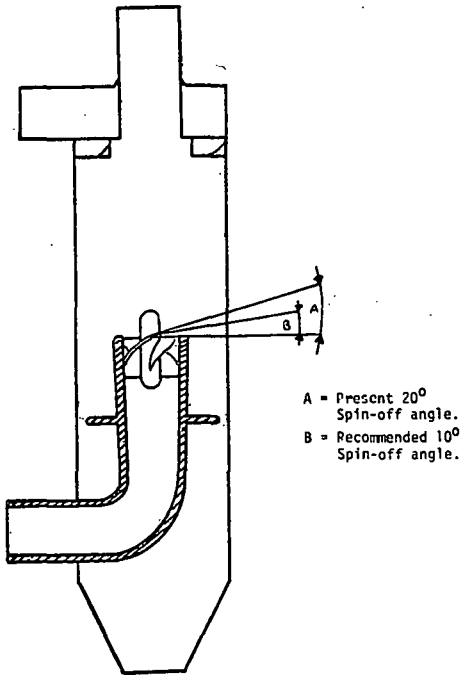


Figure 7. Aerodynamic Mechanical Collector

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OXYGEN AND OPACITY STACK-EMISSION-MONITORING SYSTEMS TO OPTIMIZE COMBUSTION EFFICIENCY AND MEET EPA REQUIREMENTS

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ABSTRACT

The combustion efficiency of industrial fuel burning equipment can be optimized through the use of oxygen and opacity stack emission monitoring systems. By providing the operator with the means to obtain accurate, continuous, dynamic feedback of the status of the products of combustion fuel - air - mixture ratios can be maintained at optimum levels resulting in improved combustion efficiency and reduced air pollution in compliance with EPA guidelines.

The smoke going up your stack is to a large part unburned fuel. The ever-spiraling cost of fuel over the past few years coupled with the world-wide energy shortage has made it imperative to operate industrial fuel burning equipment at the highest level of operating efficiency possible.

A wide variety of fuel burning emission sources can now economically use oxygen and opacity monitoring systems to optimize combustion efficiency and meet EPA requirements.

Bark & Black Liquor Boilers	Diluent Monitoring	Naval Boilers
Carbon Black (furnace process)	Driers	Oil Fired Boilers
Catalytic Crackers	Gas Fired Boilers	Oxygen Enrichment Systems
Cement, Lime Kilns	Glass Fiber	Refinery Process Heaters
Ceramic, Phosphate Kilns	Glass Melting Furnaces	Regenerative Furnaces
Chemical Recovery Boilers	Heat Treating Furnaces	Turbine Engine Test Cells
Coal Fired Utility Boilers	Incinerators	Wet Scrubbers
Coke Ovens, Soaking Pits	Kraft Recovery Boilers	Windboxes
DieselEngines	Metallurgical Furnaces	

BASIC FUNDAMENTALS OF COMBUSTION

The combustion of fuel is a chemical reaction in which fuel is combined with oxygen which results in the formation of the products of combustion and heat. The primary chemical reactions which occur during combustion are:

$$C + O_2 \rightarrow CO_2 + \text{Heat}$$

$$4H + O_2 \rightarrow 2H_2O + \text{Heat}$$

C	Carbon
H	Hydrogen
CH_4	Methane
S	Sulfur

$$CH_4 + 2O_2 \rightarrow 2H_2O + CO_2 + \text{Heat} + \text{Heat}$$

$$S + O_2 \rightarrow SO_2 + \text{Heat}$$

CO_2	Carbon Dioxide
H_2O	Water
SO_2	Sulfur Dioxide
O_2	Oxygen

Most common fuels such as coal, oil, and gas consist primarily of carbon, hydrogen, small amounts of sulfur, and trace amounts of other elements. When these fuels are mixed with oxygen at elevated temperatures, combustion will occur and the above heat-generating chemical reactions will result. In order to insure complete combustion a sufficient amount of both fuel and oxygen must be present.

In order to achieve ideal "stoichiometric" optimum combustion efficiency it is necessary to mix the fuel to be burned with the exact amount of oxygen necessary to insure complete combustion. On a practical basis there are a number of combustion variables which affect combustion. Some of these combustion variables include air and fuel pressure, air and fuel temperature, humidity, type of fuel, BTU content, moisture, specific gravity, viscosity, grindability, ash content, burner condition, fan condition, linkage wear, fire box design, etc.

In a typical fuel-burning application virtually complete combustion will occur when there is a sufficient amount of excess oxygen. Once a sufficient amount of excess oxygen is provided to complete combustion the greatest source of inefficiency is the heat loss associated with excess air in the stack emissions. (NOTE: Air is only 20.95% oxygen. As a result, in addition to oxygen, nitrogen and the other components of air also carry heat with them as they are exhausted out the stack exit.) The magnitude of these losses is determined by the stack gas exit temperature (which is a function of boiler heat transfer) and the volume of excess air in the emissions.

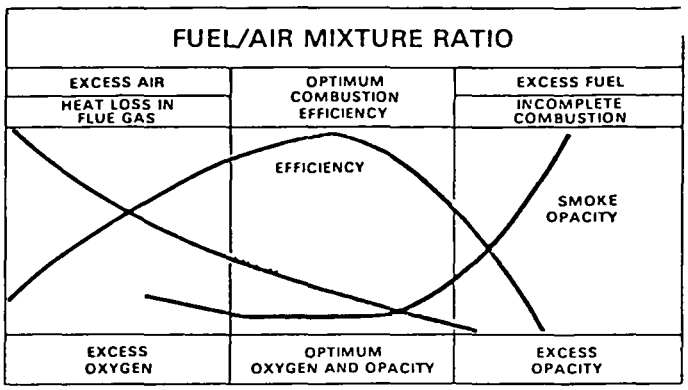


Figure 1.

An insufficient amount of oxygen can cause high smoke opacity conditions in violation of EPA regulations, slag buildup, boiler tube fouling, decreased heat transfer, excessive maintenance, wasted fuel, and potentially dangerous excess fuel conditions.

An excessive amount of oxygen can cause costly wasteful loss of energy in the form of sensible heat when excess air, in addition to that required to support combustion, is drawn into the firebox at room temperature, heated, and discharged to the atmosphere at a high temperature with the products of combustion.

In addition to saving money by reducing wasteful fuel consumption, an oxygen monitor can be helpful in reducing NO_x and SO_3 emissions due to excess oxygen, identifying burner malfunctions, reducing cold end corrosion of air heaters, and providing the dynamic feedback necessary for closed-loop automatic combustion control systems.

When the fuel/air mixture is too lean and excess oxygen is being provided, a major loss of energy occurs in the form of sensible heat in the exhaust. When excess fuel is provided there is incomplete combustion and the unburned fuel in the exhaust results in increased smoke opacity. Optimum combustion efficiency occurs when operating with the minimum amount of excess air necessary to insure complete combustion. See Figure 1.

In the above chart you can see that the loss of efficiency associated with too much excess fuel is much more severe than in the case of too much excess air. Once an adequate amount of oxygen is present to insure complete combustion and avoid the severe energy losses associated with unburned fuel it is essential that excess oxygen be kept to a minimum. With today's strict enforcement of EPA opacity regulations there is a tendency to supply too much excess air to avoid high smoke opacity conditions. The magnitude of the energy losses resulting from the presence of excess oxygen is a function of the volume and temperature of the excess air in the flue gas at the stack exit. The volume of the excess air can be reduced by operating with minimum excess oxygen. The temperature of the excess air in the flue gas at the stack exit can also be reduced by operating with minimum oxygen as a result of allowing the hot flue gases to remain in contact with the heat transfer surfaces for a longer period of time for improved heat transfer efficiency.

A typical boiler control system consists of a steam pressure transducer which senses load demand and a fuel flow controller which increases or decreases fuel flow as a function of load demand. Typically a mechanical linkage interconnects the fuel valve with the air damper. On a practical basis it is impossible to properly "characterize" the air damper to account for fluctuations in process variables such as changes

in fuel and air quality. Typically the system is set up to operate with excess oxygen to provide for occasional momentary upset conditions. As a result a majority of the time the system is operated with more excess oxygen than is necessary.

OXYGEN MONITORS

The concentration of oxygen in the flue gas passing through a stack or duct work is measured by detecting variations in the output of a zirconium oxide fuel cell oxygen sensor. As the oxygen concentration varies, an output signal is generated which can be directly related to the oxygen content of the flue gas. An In Situ Oxygen Analyzer is mounted through the wall of the stack so that the oxygen sensor cell can be in direct contact with the flue gas sample to be measured. In Situ measurement eliminates the problems associated with extractive systems which require maintenance-prone sample conditioning systems while providing a more representative sample of the gas to be measured.

An oxygen monitor is only as accurate as the sample being monitored. It is important to position the In Situ Oxygen Analyzer in a location where a representative sample is present. To avoid stratification, installations at or near junctions or bends in the stack or breech should be avoided. To avoid errors due to infiltration (air leakage) locate the In Situ Oxygen Analyzer as close to the source of combustion as possible. Avoid stagnant air pockets. Choose an In Situ Oxygen Analyzer of sufficient length to project into at least 30% of the cross sectional diameter of the stack or breech at the point of sampling. On large breeches average the output of multiple probes on either a linear or weighted average basis.

Oxygen monitors can be used to meet EPA requirements for normalizing SO_2 and NO emission levels to stoichiometric conditions. Oxygen monitors are also an excellent tool for monitoring diluent air leakage when determining the effectiveness of bag houses, electrostatic precipitators, and other types of air pollution control devices.

An oxygen monitoring system can provide the dynamic feedback necessary to enable the operator of industrial fuel-burning equipment to supply the proper amount of oxygen to insure optimum combustion efficiency. An oxygen analyzer can be used as a feedback element in a closed loop combustion control system which utilizes O_2 Trim to optimize the fuel/air mixture ratio. An Automatic O_2 Trim System compares the actual stack gas O_2 reading with a desired excess O_2 set point and generates an appropriate output control signal to the air damper draft control to automatically adjust the amount of combustion air to the burner to ensure that the desired excess O_2 set point will be maintained.

An Automatic O_2 Trim System can provide a fine trim adjustment to the combustion control system to enable it to instantaneously react to dynamic fluctuations in process variables on an automatic closed loop basis without operator intervention.

The "characterized" Set Point Function Generator utilizes a signal from the boiler master controller proportional to load to compute a corresponding excess O_2 set point. The relationship between boiler load and excess O_2 set point can be easily programmed in the field. The function generator can be used to maintain the desired fuel/air mixture ratio for each level of load demand such that the air will lead the fuel on increasing fuel-load demand and lag on decreasing fuel-load demand. See Figure 2.

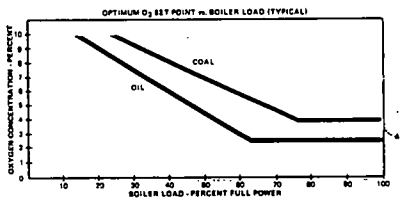


Figure 2.

The zirconium oxide fuel cell is an ideal oxygen sensor for the majority of combustion efficiency applications. For optimum performance the following application limitations should be observed: The platinum electrodes on the cell may become contaminated or poisoned in heavy reducing atmospheres in which lead, lead compounds, arsenic, or antimony are present, resulting in shortened cell life. The cell can not be used in process applications to measure oxygen in the presence of high concentrations of

combustible background gas. Stack gas temperature limits should not be exceeded. Applications involving repeated temperature cycling, mechanical, or thermal shock should be avoided.

Oxygen provides accurate reliable feedback to enable the operators of industrial fuel burning equipment to optimize combustion efficiency, minimize air pollution, reduce wasteful fuel consumption and save money. It is not adversely affected by variations in fuel composition and it is an excellent cost effective measurement technique for measuring and controlling excess air. With an oxygen analyzer the operator can measure the oxygen content of the products of combustion on a dynamic basis and adjust the fuel/air mixture ratio to compensate for fluctuations in process variables to insure operation with minimum excess oxygen.

OPACITY MONITORS

Opacity is the percentage of visible light attenuated due to the absorption and scattering of light by particulate matter in an optical medium such as flue gas.

% Opacity = 100% -% Transmittance

In a clear stack 100% of the light is transmitted and the opacity is 0%. In a stack with an opaque effluent 0% of the light is transmitted and the opacity is 100%.

The opacity of the flue gas passing through a stack or ductwork is measured by detecting variations in light transmittance. As the opacity of the effluent increases, a greater percentage of the light transmitted by the light source is deflected by the particulate matter in the smoke and the intensity of the light incident on the photo detector is reduced. The output signal generated by the photo electric light detector is directly related to effluent opacity. This signal is converted in the monitor into input signals compatible with the display, the alarm control circuits, the counter timer, and the strip chart recorder.

An opacity monitor can accurately duplicate the readings of a trained human observer watching the outlet of a stack with the advantage of being able to operate on a 24 hour basis without being affected by night time, bad weather, cloud cover, or other adverse viewing conditions.

An opacity monitor is only as accurate as the sample being monitored. It is important to position the transmissometer in a location where a representative cross-section of the emissions to be emitted from the exit of the stack can be viewed. To minimize turbulence, installations at or near junctions or bends in the stack or breech should be avoided. If it is necessary to mount the transmissometer near a bend, it should be mounted in the plane of the bend. Transmissometer path lengths less than the stack exit should be avoided. To be sure of viewing a sample representative of stack outlet conditions, the transmissometer should be mounted down-stream of air pollution control equipment.

Opacity readings have proven to be an effective means for the measurement and control of visible emissions. Key constituents of visible emissions are sub-micron particles which are a major cause of the adverse health effects of air pollution including: respiratory ailments, smog, and gas phase reactions with other air pollutants. In addition, opacity readings can be useful as an aid in optimizing combustion efficiency.

As a result of the ability of opacity monitors to demonstrate compliance and to provide data to aid in operating control equipment, it is now mandatory on a national basis for certain categories of emission sources to install and maintain approved opacity monitoring systems. The latest Federal Environmental Protection Agency (EPA) compliance requirements for stationary emission sources are outlined in the October 6, 1975 Federal Register. In addition many states and local municipalities have implemented similar legislation requiring opacity monitors on even broader categories of emission sources.

The smoke opacity monitoring system can be used to reduce wasteful excess fuel consumption by giving the operator an accurate dynamic reading of the current opacity of the products of combustion. This information is useful for the operator to lower smoke opacity levels and avoid violating EPA smoke opacity regulations. Optimum combustion efficiency can be obtained on a long term basis by operating at minimum opacity. By using the smoke opacity monitoring system to optimize combustion efficiency, carbon buildup on

The boiler tubes can be reduced, thereby improving internal heat transfer within the boiler and minimizing costly downtime for cleaning and maintenance. (Not applicable to natural gas.)

FUEL SAVING POTENTIAL

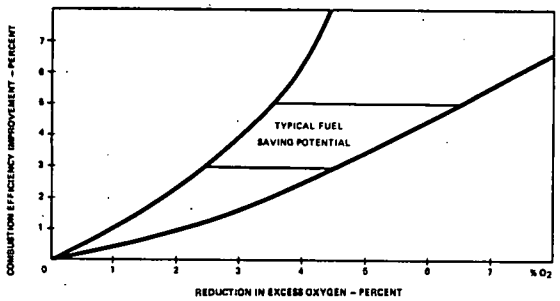


Figure 3.

The amount of money that a specific customer can expect to save by the installation of an oxygen and opacity stack emission monitoring system varies from installation to installation.

The key factors to be considered are:

1. Annual fuel consumption, type of fuel, and cost of fuel.
2. The degree of efficiency at which the plant is currently operating.
3. The capability and willingness of operating personnel to utilize the oxygen monitor in their standard operating procedures.

The real possibility of future fuel shortages, allocations, rationing, and major cost increases may dramatically change the rate of "return on investment" analysis for a particular installation. Consider the cost of shutting down the plant for one day next winter. The cost of the fuel saved becomes insignificant compared to the cost of lost production if you are faced to operate with less fuel than you have historically used.

On a practical basis, savings of as much as 3 to 5% have been obtained on many small to medium size plants.

CONCLUSION

Significant fuel savings coupled with reductions in air polluting emissions in compliance with EPA guidelines can be achieved by operating industrial fuel burning equipment at the optimum fuel/air mixture ratio through the use of the dynamic feedback provided by oxygen and opacity stack emission monitoring systems.

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COGENERATION CONSIDERATIONS IN THE 1980's

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ABSTRACT

The increasing cost of both purchased fuel and power will be the incentive to maximize the output available from cogeneration energy supply systems. This paper reviews steam and combined cycle cogeneration systems available to industrials requiring large quantities of process heat and power. Examples are developed to illustrate the economic benefit of improved systems as energy costs increase.

INTRODUCTION

Integration of turbines into industrial plant energy supply systems is not a new concept. It is a practice which has been used by many industrials during this century as an economic method of providing both shaft power and heat to the process areas. Applications of turbines in the chemical, petroleum refining, pulp and paper, metals and mining, and food industries attest to the acceptability of turbines as reliable, economic prime movers.

Cogeneration is the term popularly used to describe energy supply systems where turbines generate power (kW or hp) while providing thermal energy for use in process areas. The energy conserving aspects of cogeneration is the prime reason for the renewed interest in this technology in recent years. And with the continued increases being experienced in both fuel and purchased power cost, the industrial must strive to implement the maximum amount of power that can be economically cogenerated within the restraints imposed by plant energy demands and available fuel supplies.

EFFECTIVE ENERGY USE

The improved use of energy in various cogeneration systems is illustrated in Fig. 1. A large modern coal fired steam plant generating electric power only is indicated by the arrow on the left. The net power output is 35 percent of the fuel energy input. The output is approximately 10 percent less than that available from the best coal fired plants built before today's environmental restrictions. This 35 percent efficiency is equivalent to a 9750 Btu/kWh HHV net heat rate. If the diagram included transmission and distribution losses, the fuel required for each kilowatt delivered to the industrial would be somewhat in excess of 10,000 Btu/kWh higher heating value (HHV), a thermal efficiency of about 34 percent. The inherent cycle limitation that results in 48 percent of the fuel heat input being rejected to the condenser at about 100 F is the reason this plant efficiency is so low.

The energy utilization diagram for a large coal fired industrial using noncondensing turbines to cogenerate power prior to delivery of steam to the

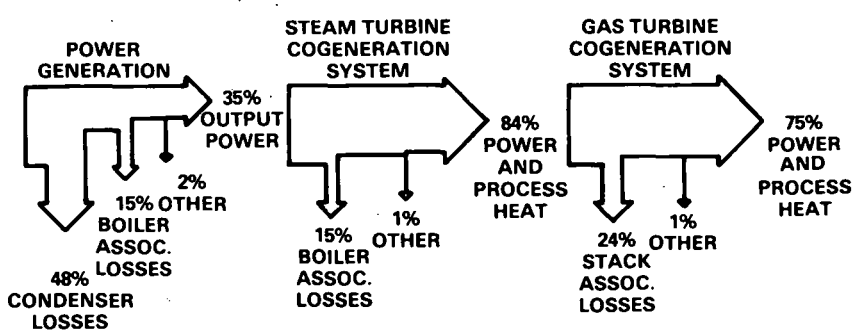
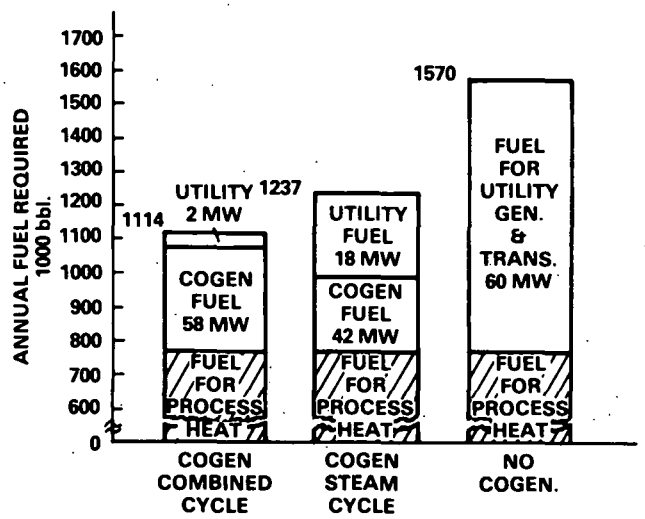


FIG. 1 - FUEL UTILIZATION EFFECTIVENESS

process steam header or headers is the center "arrow" in Fig. 1. Because the cogeneration cycle is arranged to reject its heat at the higher temperatures required in process, the condenser loss is eliminated (or minimized). Thus, the total useful energy delivered, both process steam and shaft power, is 84 percent of the fuel energy input and the fuel chargeable to cogenerated power is about 4100 Btu/kWh.

A similar energy utilization diagram for a gas turbine with exhaust heat recovery is given in the righthand portion of Fig. 1. For this fuel oil fired unit, the unfired exhaust heat recovery system results in a 300°F stack temperature. Gas turbine cogeneration systems which use the turbine exhaust gas as preheated combustion air can result in a fuel utilization effectiveness approaching 84 or 85 percent.

The data given in Fig. 2 shows the fuel oil savings available with either a steam turbine or combined cycle cogeneration system providing 500 million Btu/hr net heat to process at 50 psig. This figure also illustrates the increased output available from a gas turbine combined cogeneration cycle relative to a steam turbine cogeneration cycle at the same process heat demand.



Basis:
1) Process plant requirements
60,000 kW plus 500 million Btu/hr net in 50 psig process steam
2) Utility gen. and trans.
10,000 Btu/kWh delivered

FIG. 2 - COGENERATION REDUCES TOTAL FUEL FOR INDUSTRIAL HEAT AND POWER

Since power produced in cogeneration cycles can result in significant energy savings compared to fossil fuel fired plants designed to provide power only, careful attention to system detail is required to optimize cogeneration cycles economically.

ENERGY SYSTEMS CONSIDERATIONS

Fuel Chargeable to Power - Definition

Fuel chargeable to power (FCP) generation in the industrial plant is simply the extra increment of fuel for the plant with in-plant generation versus the fuel required for process heat when all electric power is purchased. For a plant generating electric power only (an industrial or a utility), "Fuel Chargeable to Power" and "Net Plant Heat Rate" are interchangeable terms. "Net Plant Heat Rate" in Btu/kWh is the more commonly used term for plants generating electric power only.

Fuel chargeable to power is usually lowest when the total electric power requirement can be generated with steam turbines expanding boiler steam to the lower pressures needed to supply process heat at the desired temperature. The fuel required to generate this cogenerated power is simply:

$$FCP = \frac{3412}{eff_{boiler} \times eff_{mech\ \&\ elec} \times eff_{incremental\ PH\ aux.}}$$

Or, for a typical steam turbine example:

$$\text{Net FCP} = \frac{3412}{87\% \times 98\% \times 98\%} = 4080 \text{ Btu/kWh HHV}$$

Stated in simple terms, the FCP is the total fuel burned in the cogeneration system, minus the fuel which would have been required if all power was purchased (process fuel credit), divided by the gross power generated minus the difference in powerhouse auxiliaries. (See Fig. 3). The validity of this relationship can be checked by applying this equation to a system supplying no process heat. Then:

$$FCP = \frac{(Fuel)_2}{kW\ Gross - PH\ Aux.}$$

This is the traditional definition of heat rate used to define the performance of fossil fuel fired utility plants.

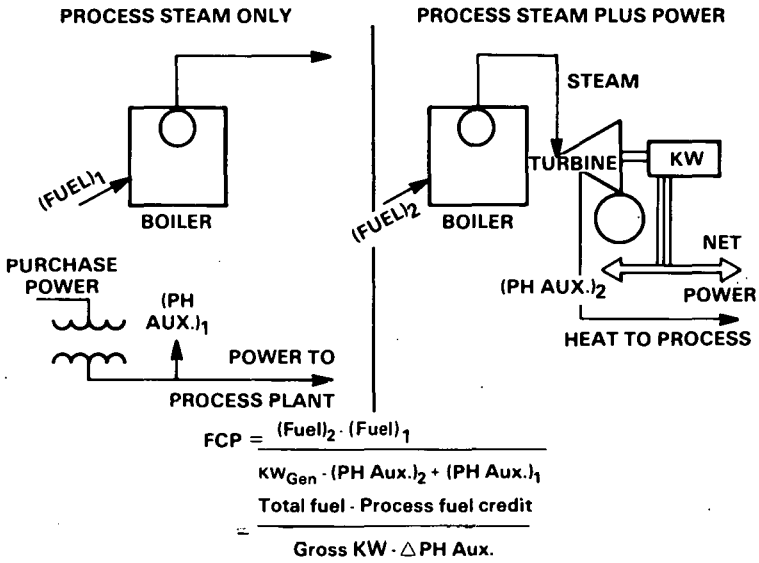


FIG. 3 - FUEL CHARGEABLE TO POWER

STEAM TURBINE CYCLES

For most industrial plants, the process steam demands are not large enough to permit production of all electric power requirements as cogenerated steam turbine power. Thus, to economically exploit the advantages of cogeneration, consideration must be given to the following aspects of the system.

- Prime mover size
- Initial steam conditions
- Process steam pressure
- Feedwater heating system

Prime Mover Size

The influence of prime mover size on the amount of power that can be cogenerated is shown in Table I. Based on a constant net heat to process (NHP) requirement of 100 million Btu/hr, the larger, more efficient steam turbine-generator will provide about 70 percent more cogenerated power relative to that available from a group of small mechanical drive turbines. Since the more efficient unit provides "cooler" steam to process, the mass flow to be expanded through the turbine-generator to provide the same NHP is greater than the flow for the mechanical drive case. Thus, for the 70 percent increase in output shown in Table I, 60 percent is due to the higher efficiency and the balance due to the increased flow for the turbine-generator.

If the mechanical drive units are replaced with motors, and the efficiency from the turbine bus bar to each mechanical load is 88 percent, 3180 kW must be supplied in the equivalent electrical drive system. Thus, the net gain in cogenerated power for the Table I example would be about 57 percent.

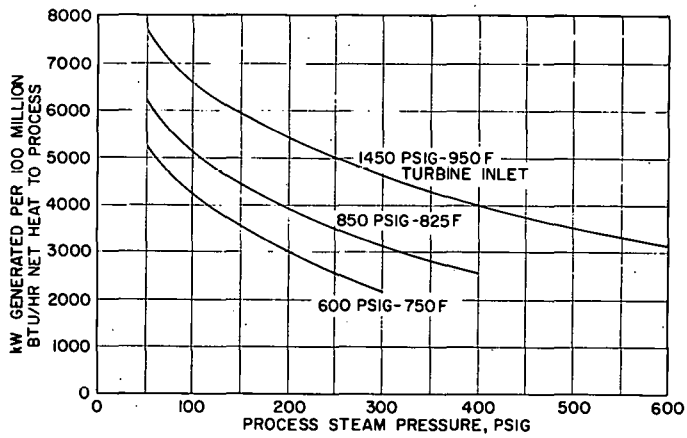
TABLE I - INFLUENCE OF PRIME MOVER SIZE ON COGENERATED POWER

TYPE PRIME MOVER	APPROX. EFFICIENCY	COGENERATED POWER PER 100 MILLION BTU/HR NET HEAT TO PROCESS
500 hp Single Stage Mechanical Drive Units	45%	2800 kW eq.
5000 kW Multi Valve Multi Stage Turbine-Generator	72%	4770 kW

Basis:
1) Initial steam conditions, 600 psig, 750 F.
2) Process steam required at 50 psig.
3) Process returns at 180 F.
4) No feedwater heating has been included.

Turbine Inlet Steam Conditions

The effects of turbine inlet steam conditions on the amount of power that can be cogenerated per 100 million Btu NHP at different process steam pressures is shown in Fig. 4. The increased power generating potential as steam conditions increase shown in Fig. 4 is primarily due to the increased steam pressure.



Basis:
1) 70% of process steam flow returned as 200 F condensate and balance as 80 F makeup.
2) Power cycle credited for feedwater heating to 445 F for 1450 psig unit, 400 F for 850 psig, 370 F for 600 psig.
3) Turbine efficiency 75%.

FIG. 4 - EFFECT OF INLET STEAM CONDITIONS AND PROCESS STEAM PRESSURE ON POWER COGENERATED WITH STEAM TURBINES

Although increased steam temperature increases the available energy, it also increases the temperature level of the steam supplied to process. Since highly superheated process steam is not generally desired, a turbine exhaust at a high steam temperature must often be desuperheated prior to delivery to the steam use areas. If desuperheating is required, the steam flow through the turbine must be reduced by the quantity of desuperheating water required. Thus, cogenerated power is not materially increased through use of higher initial steam temperatures.

The evaluation of higher initial steam conditions examines whether the increase in cogenerated power results in adequate incremental annual operating cost savings to justify the increased investment for the cogeneration system. For example, if an industrial plant required 500 million Btu/hr NHP at 200 psig, use of 1450 psig, 950 F rather than 850 psig, 825 F would increase cogenerated power 7700 kW. And if fuel was valued at $3/million Btu, and the added generation displaced purchased power at a cost of 4¢/kWh, the higher steam conditions would reduce annual operating costs about $1,800,000 based on 8400 hr/yr operation at the conditions noted. Furthermore, if a gross payout period of three years was considered acceptable for industrial investments, up to $5,400,000 could be invested for the higher steam conditions. That represents about $700/kW incremental cost for the higher steam conditions, somewhat increased boiler and turbine ratings as well as possible increases in the feedwater treatment system costs.

Studies have shown that the higher initial steam conditions can usually be economically justified in industrial plants having relatively large process steam demands. The data given in Fig. 5 provides guidance to the range of initial steam conditions that should be considered for industrial steam turbine cogeneration systems. With continued increases in purchased fuel and power costs, inlet steam conditions toward the top of the "bands" shown in Fig. 5 will probably be economic.

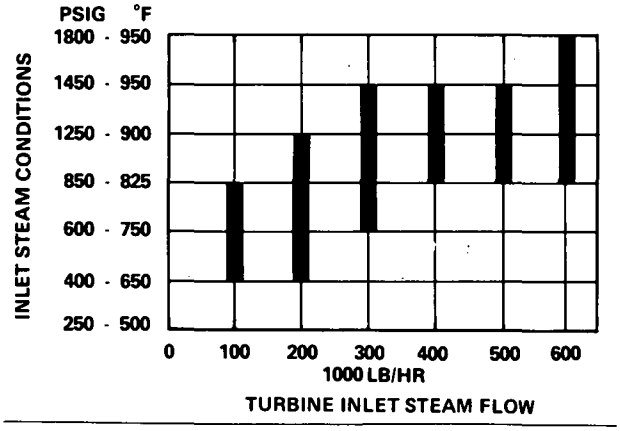


FIG. 5 - RANGE OF INITIAL STEAM CONDITIONS NORMALLY SELECTED FOR INDUSTRIAL STEAM TURBINES

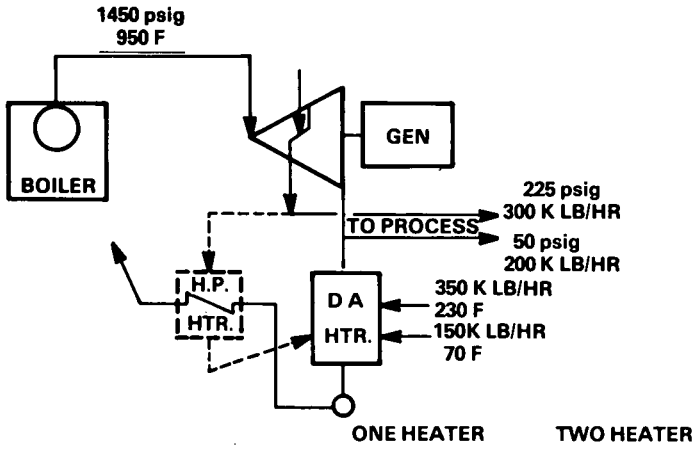
Process Pressure Level

The use of the lowest possible process pressure level also enhances steam turbine cogenerated power. For example, if the designer has the option of developing a process at 50 psig rather than 75 psig, and initial steam conditions are 850 psig, 825 F, the lower process pressure will increase cogenerated power 600 kW per 100 million Btu/hr NHP. And if the total process requirements are 500 million Btu/hr NHP, an additional 3000 kW would be generated. The resulting annual energy cost savings would have to be compared with the increase in the cost of the turbine-generator, the boiler, the plant steam distribution system, and possibly process equipment costs to determine whether the lower process pressure can be economically justified. This example also illustrates the gains which are forfeited if plants are designed with too much margin in the process steam distribution systems.

Feedwater Heating

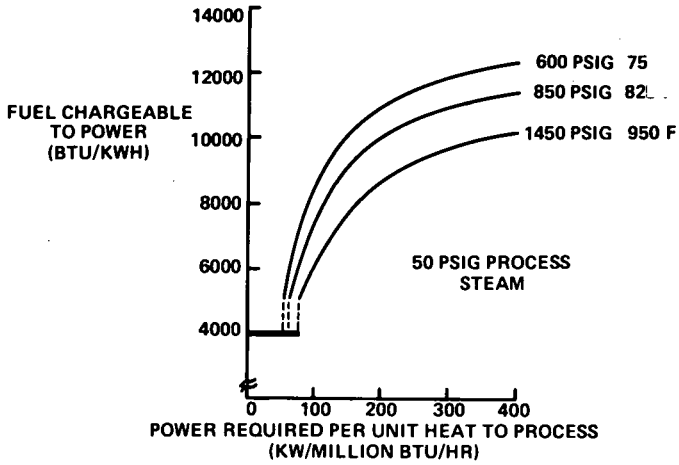
The use of additional stages of feedwater heating will often result in substantial increases in by-product power generation, particularly in industrial plants requiring large quantities of process steam and therefore boiler feedwater flow. The effect of feedwater heating on cogenerated steam turbine power is illustrated in Fig. 6. The addition of the high pressure feedwater heater operating at the 225 psig pressure level results in a 2870 kW net increase in cogenerated power. This represents an 8.3 percent increase in net power output for the cycle presented compared to operation with the deaerating heater alone. Based on $4/million Btu fuel cost and 45 mills/kWh purchased power, this additional stage of feedwater heating would reduce annual plant energy costs by almost $700,000.

As additional feedwater heaters are introduced into the cycle, the gains in performance usually become less. Generally speaking, the use of three stages of feedwater heating is economical for most



	ONE HEATER	TWO HEATER
THROTTLE FLOW (1000 LB/HR)	560.0	618.0
STEAM TO DA (1000 LB/HR)	59.9	58.5
STEAM TO HP HTR (1000 LB/HR)	NA	59.4
POWER GENERATED	34.77 MW	37.64 MW
NET INCREASE	BASE	2.87 MW

FIG. 6 - EFFECT OF ADDED FEEDWATER HEATING ON COGENERATED STEAM TURBINE POWER



Basis:
1) Cycle specifics as in Fig. 4.
2) FCP based on credit for process heat at 88% boiler efficiency.

FIG. 7 - FUEL CHARGEABLE TO POWER - VARIOUS STEAM TURBINE CYCLES

industrial process plants utilizing steam turbine cogeneration cycles.

Condensing Power Generation

Even through use of the most efficient steam turbine cogeneration alternatives, there are few industrials which can expect to generate all of their electric power needs using cogenerated steam turbine power. This situation has been accented by recent efforts in most industries to conserve energy which has resulted in reduced process steam demands with little or no corresponding decrease in electric power requirements. In fact, many industries are experiencing increased kilowatt loads per unit of product produced due to the increased power required in many areas for environmental compliance. Thus, a purchased power tie and/or condensing generation is necessary to provide the balance of the plant power needs.

Even though condensing power generation requires significantly more fuel than cogenerated steam turbine power, it has proven economic in some industrial applications. Generally speaking, favorable economics are associated with limiting purchased power demand. In other cases, condensing power provides the continuity of service often considered critical in certain industrial applications where loss of the utility tie can cause a major disruption in process operation.

The impact of condensing power generation considering the effect of various initial steam conditions on the fuel chargeable to power (FCP) for a plant requiring process heat and power is shown in Fig. 7. This figure permits determination of the maximum amount of cogenerated power available based on a certain ratio of power per unit of process heat required as steam at 50 psig. The points where the fuel chargeable to power rapidly increases is where a condensing end must be added to the turbine-generator. As the power required per unit of process heat increases, the performance asymptotically approaches the fuel chargeable to power for a straight condensing steam turbine cycle based on the steam conditions and feedwater heating cycle noted.

GAS TURBINE CYCLES

Gas turbine cycles provide the opportunity to generate a larger power output per unit of heat required in process relative to noncondensing steam turbine cogeneration cycles. This characteristic combined with a favorable FCP and proven reliability is why this prime mover has been widely accepted in industrial plants where suitable fuels are economically available.

The economics of gas turbines in process applications usually depends upon effective use of the exhaust energy. The most common use of this energy is for steam generation in heat recovery steam generators (HRSG), unfired as well as fired designs. However, the gas turbine exhaust gases can also be used as a source of energy for unfired and fired process fluid heaters, as well as combustion air for

power boilers.

Heat Recovery Steam Generators

The overall effectiveness of energy use in a gas turbine-heat recovery system is a function of the amount of energy transferred from the turbine exhaust gas. The greater the amount of energy transferred, the lower the HRSG stack temperature, and the greater the efficiency of energy use. Thus, gas turbine HRSG cycles should use low feedwater temperatures to the economizing section of the HRSG within constraints imposed due to corrosion considerations in the HRSG economizer. Typical feedwater temperature is 230 F if corrosion is not a problem, and about 265 F for applications involving sulfur bearing fuels. This is in contrast to steam turbine cycles which provide increased cogenerated power as more regenerative feedwater heating is incorporated into the cycle.

The amount of steam which can be generated in the exhaust of the General Electric G5341(P), G6441(A) and G7981(E) distillate oil fired gas turbine-generators is given in Table II. Considerations with regard to the three types of HRSG units, i.e. unfired, supplementary fired and fully fired follow.

Unfired HRSG - The simplest application of heat recovery steam generators is the use of an unfired unit in the gas turbine exhaust. Characteristically, steam conditions range from 150 psig saturated to approximately 895 psig, 830 F. Steam temperatures are usually 100 F or more below the turbine exhaust gas temperature.

TABLE II - STEAM GENERATION AND GAS TURBINE FUEL CHARGEABLE TO POWER (DISTILLATE OIL FUEL)

Gas Turbine Model/Rating	G5341(P) - 24,700 kW ISO		G6441(A) - 31,050 kW ISO		G7981(E) - 75,000 kW ISO	
Gas Turbine (Unfired/ Supp. Fired/Fully Fired)						
Fuel - M Btu/hr HHV	297		344		783	
Output - MW	21.8/21.6/21.4		27.8/27.6/27.3		67.5/67.2/66.8	
Airflow - 1000 lb/hr	915		1003		2062	
Exhaust Temp. - °F	920/922/925		912/914/917		996/998/1001	
HRSG Fuel - M Btu/hr HHV	0/190/769		0/103/825		0/187/1617	
Steam Conditions	Steam 1000 lb/hr	FCP Btu/kWh HHV	Steam 1000 lb/hr	FCP Btu/kWh HHV	Steam 1000 lb/hr	FCP Btu/kWh HHV
Unfired Boilers						
250 psig sat.	133	6560	141	6540	348	5650
400 psig - 650 F	110	7020	116	6950	292	5960
600 psig - 750 F	101	7340	105	7230	271	6160
850 psig - 825 F	93	7650	97	7520	255	6340
Supplementary Fired (1300 F avg)						
400 psig - 650 F	206	5630	226	6070	464	5420
600 psig - 750 F	195	5660	215	6180	441	5510
850 psig - 825 F	189	5700	207	6280	426	5600
1250 psig - 900 F	182	5750	201	6400	412	5700
1450 psig - 950 F	177	5750	195	6490	401	5780
Fully Fired						
600 psig - 750 F	722	4010	773	4350	1571	3990
850 psig - 825 F	703	↓	753	↓	1531	↓
1250 psig - 900 F	687		736		1496	
1450 psig - 950 F	675		723		1469	

Basis:

1) *Gas turbine performance given for 80 F ambient temperature, sea level site.*
2) *HRSG performance based on 3% blowdown, 1½% radiation and unaccounted losses, 228 F feedwater.*
3) *No HRSG bypass stack loss.*
4) *Gas turbine exhaust pressure loss is 10" H_2O with unfired, 14" H_2O with supplementary fired and 20" H_2O with fully fired HRSG.*
5) *Fully fired HRSG based on 10% excess air following the firing system and 300 F stack.*
6) *Fuel chargeable to gas turbine power assumes total fuel credited with equivalent 88% boiler fuel required to generate steam.*
7) *Steam conditions are at utilization equipment. A 5% ΔP and 5 F ΔT have been assumed from the outlet of the HRSG.*

Generally speaking, unfired units can be economically designed to recover approximately 92 percent of the energy in the turbine exhaust gas available for steam generation. Higher performance levels are possible; however, the increased cost of heat transfer surface must be evaluated versus additional energy recovered to establish whether the higher costs are warranted.

Supplementary Fired HRSG - The oxygen content of the gas turbine exhaust may permit supplementary fuel firing ahead of the boiler to increase steam production rates relative to an unfired unit. Since the turbine exhaust gas is essentially preheated combustion air, the supplementary fuel fired exhaust heat recovery boiler fuel consumption is less than that required for a power boiler providing the same incremental increase in steam generation. Characteristically, the exhaust heat boiler fuel consumption, for a unit fired to 1300 F average gas temperature into the unit, will be 20 to 25 percent less than for an oil fired power boiler (88 percent efficient) providing the same incremental increase in steam produced.

Fully Fired HRSG - Considerations for additional steam production should not be limited to the steam production rates associated with low firing temperature levels. Some industrials use the exhaust of the gas turbine as preheated combustion air for a fully fired exhaust heat boiler. A fully fired boiler is defined as a unit having the same amount of oxygen in its stack gases as an ambient air fired power boiler.

Steam production rates for fully fired boilers (10 percent excess air) may range up to six or seven times the unfired boiler steam production rate. The actual increase is a function of the oxygen remaining for combustion and the gas turbine exhaust temperature. Because of the use of preheated combustion air, fuel requirements for fully fired units will usually range between 7.5 and 8 percent less than that of an ambient air fired boiler providing the same incremental steam generating capacity. With the more efficient gas turbines (higher firing temperatures resulting in lower O_2 content in the exhaust gases) and for some boiler fuels, the ability of igniting and maintaining stable combustion should be confirmed with the HRSG manufacturer.

COMBINED CYCLES

Combined cycles offer the energy supply system designer the opportunity of combining the benefits of both steam turbine and gas turbine cogeneration systems into a single application. The resultant energy supply system can often provide large quantities of power at significant fuel savings.

The output available with various combined cycles using the General Electric G5341(P) and G7981(E) distillate oil fired gas turbines is given in Fig. 8. Typical power available from noncondensing steam turbine cogeneration cycles is also included for comparison. This figure shows that combined cycles can provide up to four times the amount of power available from a typical steam turbine cogeneration cycle.

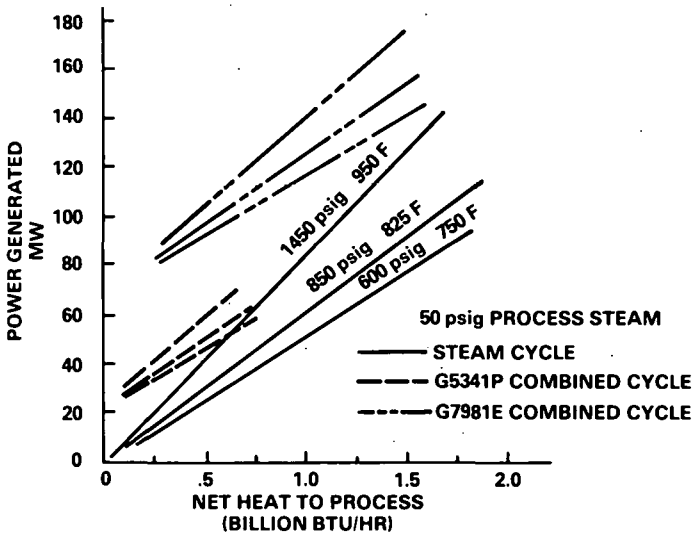
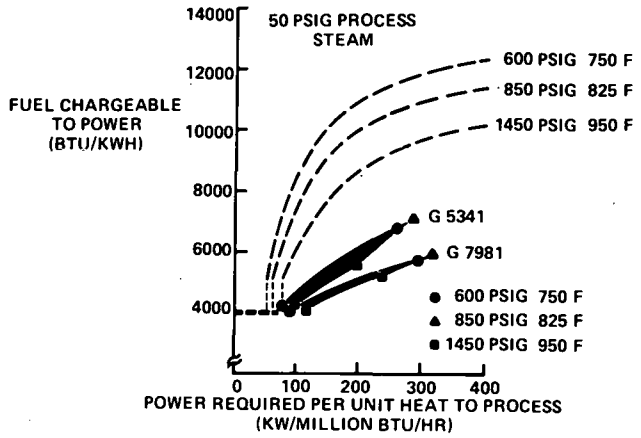


FIG. 8 - COGENERATED POWER AVAILABLE WITH VARIOUS CYCLES

The FCP available for industrial applications requiring 50 psig process steam and using the gas turbine cycles presented in Fig. 8 is given in Fig. 9. For comparative purposes, the steam turbine cycle data which were presented in Fig. 4 are also included.

Figure 9 shows that the maximum amount of cogenerated power available in a steam turbine cycle is limited to about 90 kW/M Btu/hr net heat required as 50 psig process steam. In contrast, the combined steam-combustion turbine cycle using the 25 MW G5341(P) unit can provide as much as 285 kW/M Btu/hr at a FCP of 7100 Btu/kWh, and the 75 MW G7981(E) unit permits a maximum generation of about 315 kW/M Btu/h



Basis:

1) *Process pressure 50 psig.*
2) *Dashed lines for steam cycles are identical to Fig. 7.*
3) *FCP based on summation of gas turbine plus noncondensing steam turbine power and process heat credit at 88% boiler efficiency.*
4) *Feedwater temperature to HRSG is 228 F.*
5) *Gas turbine fuel is No. 2 fuel oil.*

FIG. 9 - FUEL CHARGEABLE TO POWER - COMBINED CYCLES

at a FCP of 5900 Btu/kWh. The advantage of the combined cycle performance relative to the steam cycles at high kW/NHP ratios results from displacing condensing power at a FCP in excess of 10,000 Btu/kWh with the gas turbine and its HRSG at a FCP in the 4000 Btu/kWh to 7000 Btu/kWh range.

The use of higher initial steam conditions in unfired HRSG applications will result in higher HRSG stack gas temperatures compared to the temperature which would be attained if low pressure process steam was generated in the HRSG. However, the use of a dual pressure level unfired HRSG permits the system design to benefit from steam turbine cogeneration and the lower stack gas temperature available with the two-pressure level HRSG.

The improved performance available through use of a dual pressure HRSG in the exhaust of the G5341(P) turbine-generator is shown in Table III.

TABLE III - COMPARISON OF SINGLE VS. DUAL PRESSURE UNFIRED HEAT RECOVERY STEAM GENERATOR

(G5341(P) Gas Turbine, 24,700 kW ISO Dist. Oil Fired)

TYPE UNIT	SINGLE PRESSURE	DUAL PRESSURE
Steam Conditions (psig/F)		
High Pressure HRSG	850/825	850/825
Low Pressure HRSG	NA	150/sat.
Steam Flow (1000 lb/hr)		
High Pressure HRSG	93.1	93.1
Low Pressure HRSG	NA	28.2
Stack Temperature (F)	433	300
Output (MW)		
Gas Turbine	21.8	21.8
Steam Turbine	3.8	3.8
Total	25.6	25.6
Net Heat Delivered from HRSG to Process (mil. Btu/hr)	100	128
Fuel (mil. Btu/hr HHV)		
Gas Turbine	296.7	296.7
Process Fuel Credit	113.6	145.5
Net	183.1	151.2
Overall Fuel Chargeable to Power (Btu/kWh)	7150	5900

Basis:

1) *Gas turbine operated at sea level site, 80 F ambient.*
2) *Gas turbine inlet pressure loss 4" H_2O, exhaust pressure loss is 10" H_2O with single pressure, 12" H_2O with dual pressure HRSG.*
3) *Turbine exhaust flow is 915,000 lb/hr, exhaust temperature ~920 F.*
4) *Steam conditions given are at the utilization equipment; losses of 5% ΔP and 5 F ΔT from the HRSG outlet are assumed.*
5) *HRSG performance includes 3% blowdown, 228 F feedwater.*

EFFECT OF INCREASED ENERGY COSTS ON COGENERATION ECONOMICS

The benefits resulting from the effective designs of cogeneration systems will probably pay increased dividends as energy costs increase in future years. The improved profitability of cogeneration with time is due to the lesser impact of fuel cost increases on the cogenerator relative to a fossil fuel fired plant designed to provide power alone.

The impact of fuel cost increases on various fossil fuel fired power generating facilities can be estimated using Fig. 10. This figure shows that the best industrial can tolerate a fuel cost increase 2½ times that of the 10,000 Btu/kWh utility before his incremental increase in energy cost exceeds that which would have been passed on to the industrial user via the automatic fuel adjustment provision of most utility rate schedules. Thus, it does not appear unreasonable to project that savings and thus the profitability of an investment in cogeneration will probably be enhanced in the coming years.

In order to objectively assess the economic viability of cogeneration for a given industrial

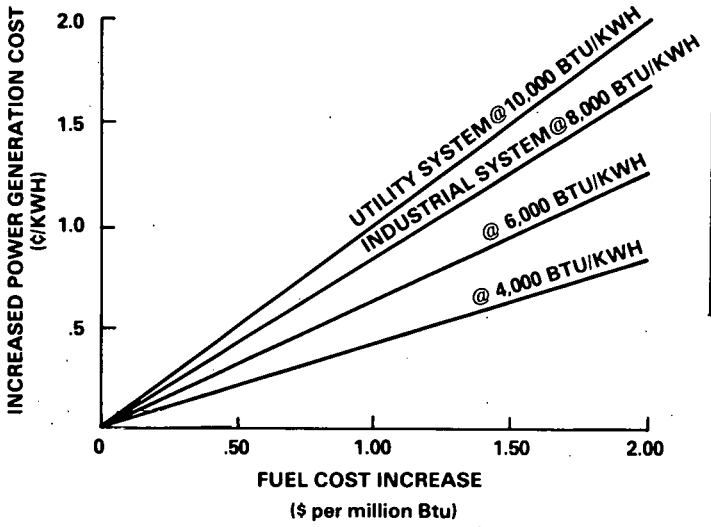


FIG. 10 - EFFECT OF FUEL COST INCREASES ON POWER GENERATION COST

TABLE IV - INDUSTRIAL PLANT ENERGY SUPPLY SYSTEM REQUIREMENTS (EXAMPLE)

• Electric Power	- 30,000 kW (process area)
• Net Heat to Process @ 50 psig	- 150 million Btu/hr
• Condensate Returns	- 45% @ 300 F
• Makeup Water	- 60 F
• Plant Fuel - Fuel Oil @	- $5/million Btu
• Purchased Power	- 5¢/kWh

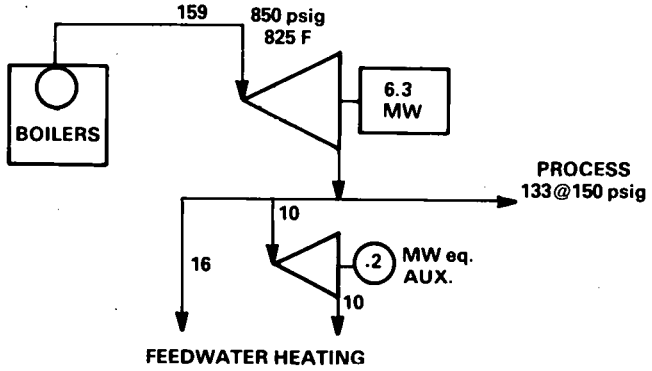
plant, the analysis should factor the projected future changes in energy costs into the evaluation. This type of evaluation and its impact on the economics relative to an evaluation which looks at simply one set of energy costs is illustrated in the following example.

For the plant data given in Table IV, the following alternatives are being considered:

Base Case -- The industrial plant provides all process steam demands and purchases plant electrical requirements from the utility.

Case 1 -- A typical steam turbine cogeneration system as shown in simplified form in Fig. 11.

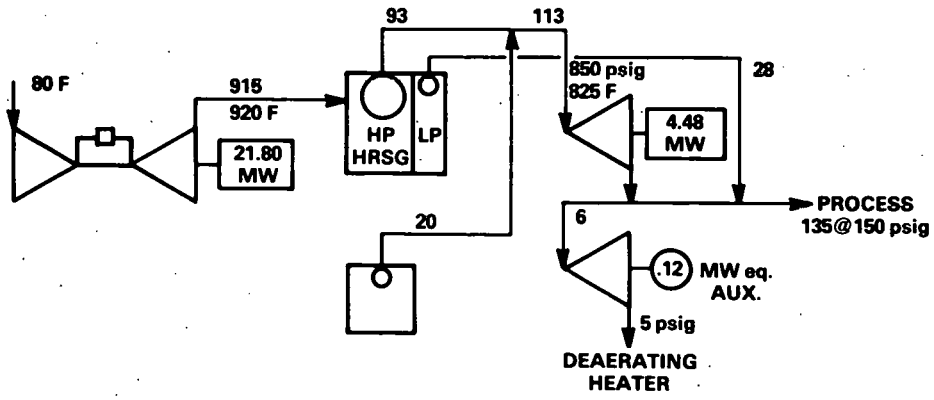
Case 2 -- A typical combined cycle with a 24 MW gas turbine-generator and a two-pressure level HRSG. This system is illustrated in Fig. 12.



NOTE: ALL NUMBERS ARE FLOWS IN 1000 LB/HR

GROSS GENERATION	6.5 MW
POWERHOUSE AUXILIARIES	.5 MW
NET GENERATION	6.0 MW

FIG. 11 - TYPICAL STEAM TURBINE COGENERATION CYCLE CASE 1



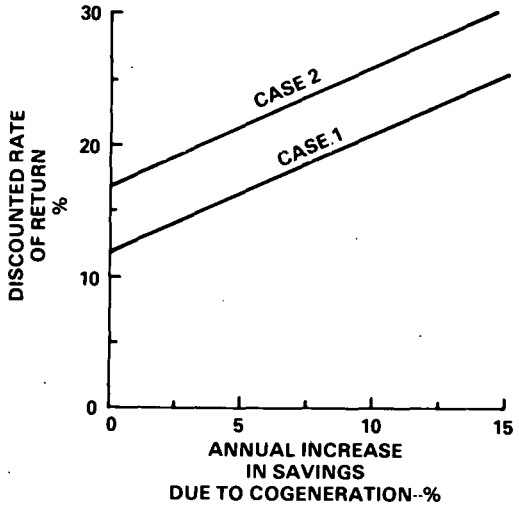
NOTE: ALL NUMBERS ARE FLOWS IN 1000 LB/HR

GROSS GENERATION	26.4 MW
POWERHOUSE AUXILIARIES	.4 MW
NET GENERATION	26.0 MW

FIG. 12 - TYPICAL COMBINED CYCLE COGENERATION SYSTEM CASE 2

The annual operating costs and economics for the cases examined are given in Table V. The economic merit for each cogeneration alternative has been expressed as its gross payout period (GPO) based on the first year's annual operating cost savings relative to the Base Case. The GPO of 4.5 years for Case 1 is equivalent to a discounted rate of return (DRR) of 12 percent; the 3.2 year GPO for Case 2 is equivalent to a 16.9 percent DRR. (The basis for the DRR values is given in Fig. 13).

The rate of return values quoted do not include the influence of increased (or decreased) annual operating cost savings in future years. The impact of increased annual savings with time, regardless of the reason for the increased annual savings, on the DRR is shown in Fig. 13. If one assumes the savings will increase 5 percent per year, the DRR for Case 1 would increase from 12 percent to 16.5 percent, and Case 2 would increase from 16.9 percent to 20.4 percent.



Basis:
1) *Depreciation period 28 years.*
2) *Sum-of-the-years-digits depreciation.*
3) *Economic life 28 years.*
4) *Local property taxes and insurance 4% of investment cost.*
5) *State and Federal income taxes 50%.*
6) *Investment tax credit 10% of investment cost.*

FIG. 13 - EFFECT OF INCREASED ANNUAL SAVINGS ON THE ECONOMICS OF COGENERATION

TABLE V - ANNUAL OPERATING COST AND ECONOMICS INDUSTRIAL PLANT (EXAMPLE)

ALTERNATIVE	BASE	1	2
Type Cogeneration Cycle	NA	steam	combined
Fuel (million Btu/hr HHV)	172	198	325
Power Generated (MW)			
Steam Turbine	NA	6.5	4.6
Gas Turbine	NA	NA	21.8
Power Plant Auxiliaries (MW)	.3	.5	.4
Power Purchased (MW)	30.3	24.0	4.0
Annual Operating Cost ($ Millions)			
Fuel @ $5/million Btu	7.22	8.31	13.65
Purchased Power @ 5¢/kWh	12.73	10.08	1.68
Standby Power @ $25/kW-yr	NA	.16	.67
△ Operating Labor	Base	.24	.24
△ Maintenance	Base	.14	.31
△ Makeup Water	Base	.03	.03
Total	19.95	18.96	16.58
Savings	Base	.99	3.37
Incremental Investment ($ Millions)	Base	4.5	10.8
Gross Payout Period - years	Base	4.5	3.2

Basis:
1) *Power boiler efficiency 87%.*
2) *Cost based on 8400 hr/yr operation at Table IV requirements.*
3) *Standby power charge provides utility service if the turbine-generator is out of service.*
4) *Investment costs do not include the cost of land. Site location is U.S. Gulf Coast area.*
5) *Maintenance is 2½% of the estimated incremental investment cost.*
6) *Makeup water cost based on incremental cost of 40¢/1000 gal.*

CLOSURE

This paper has discussed several factors which contribute toward the effective development of economic industrial cogeneration systems. Also, general application data have been included to provide guidance in planning cogeneration systems for new industrial plants and/or modernization and expansion of existing facilities.

The cost of all forms of energy is rising sharply. Cogeneration for industrials requiring large quantities of process heat should continue to be an important factor in conserving our energy resources and maintaining control of the costs of goods produced.

CASE STUDIES OF INDUSTRIAL COGENERATION IN THE U.S.

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ABSTRACT

This paper describes the results of a survey and evaluation of plant-specific information on industrial cogeneration. The study was performed as part of a project sponsored by the Electric Power Research Institute to evaluate Dual Energy Use Systems (DEUS). The purpose of this project was to evaluate site-specific data on DEUS from the utility perspective, identify promising candidates, and define R&D opportunities. The first major task in this DEUS project was a survey of industrial cogeneration sites to identify the technoeconomic and institutional factors affecting the success of cogeneration systems in industry. Sites were selected based on a mix of industry types, geographic location, type of cogeneration system, generating capacity, age of plant and other characteristics. Site-specific surveys were conducted and supplemented by information from secondary sources such as FERC and DOE statistical data systems. This paper presents information on 17 cogeneration facilities. Also presented is information on the perspectives of the relevant utilities.

INTRODUCTION

Cogeneration is receiving increasing publicity and is frequently mentioned as an important energy conservation measure. Cogeneration has been the subject of many recent studies, which have addressed the policy issues related to cogeneration from a national perspective. However, there is some ambiguity and a lack of adequate understanding regarding some of the complex technical, economic and institutional issues related to cogeneration. This paper describes the results of case studies of 17 industrial cogeneration sites. The case studies were performed as part of a project sponsored by the Electric Power Research Institute for the Evaluation of Dual Energy Use Systems (DEUS).

WHAT IS DEUS?

Cogeneration has been traditionally defined as the simultaneous production of electricity and steam. Recently, the definition has been broadened to include the simultaneous production of electricity and any useful thermal energy.(1) It is felt in some circles that even this definition is too restrictive and should be broadened. The Manufacturing Chemists Association has suggested that the term "cogeneration" be defined to include the generation of electrical or mechanical work and useful thermal energy from the same primary energy source.(2)

In order to distinguish between the narrower definition of cogeneration conventionally used from the more general and expanded definition, the electric utility industry has defined the term "Dual Energy Use Systems (DEUS)" for referring to simultaneous production of useful thermal and electric energy from a common source.(3) While industrial cogeneration (DEUS) is not a new concept and a number of industrial cogeneration plants have been operated for several decades, there is little published information on a site-specific basis on the major technical, economic and institutional aspects of these systems.

THE EPRI DEUS PROJECT

The Electric Power Research Institute (EPRI) conducted a Dual Energy Use Systems Workshop in September 1977 to develop information useful to utilities, process industries, and others concerned with the problems and prospects of DEUS. One of the findings of the Workshop was:

> "Although much has been written on the various applications, such as cogeneration and district heating, not enough site-specific information is available to provide a basis for an accurate estimate of the real potential for this concept."(4)

EPRI is now undertaking a two-pronged program for the Evaluation of Dual Energy Systems Applications.(5) This program addresses both industrial cogeneration and district heating, and its overall objectives are to:

- Develop a methodology to assess DEUS options, giving explicit consideration to utility perspectives.
- Identify promising DEUS candidates.
- Identify research and development needs and priorities.

An overview of the cogeneration program is shown in Figure 1.

The first step in the EPRI DEUS program is to assess the current status of DEUS in the United States. The first two tasks of the program consist of surveys and case studies of industrial cogeneration and district heating systems.

OBJECTIVES OF COGENERATION CASE STUDIES

The principal objective of the case studies of industrial cogeneration described in this paper was to identify and describe the major technical, economic and institutional aspects of existing industrial cogeneration systems. The factors addressed include the types of cogeneration systems and components, relative thermal and electric output of cogeneration systems, capital investments, operating and maintenance costs, fuel costs, institutional arrangements for ownership and operation, interaction with local electric utility, etc.

Another important objective was to develop an understanding of the perspective of electric utilities towards industrial cogeneration. In particular, the study attempted to identify the utility attitudes and concerns regarding the advantages and disadvantages of cogeneration, requirements and terms which would make cogeneration attractive, and perceived problems.

The detailed results of the case studies are presented in a forthcoming report to be published by EPRI in Summer 1980.(6)

CRITERIA FOR SELECTION OF CASE STUDY CANDIDATES

The cogeneration systems studied in this project were selected after a formal screening process. An initial list of cogenerators was prepared by TRW and screened using three criteria.(7) Because of the difficulties in obtaining data from some of the selected candidates, Synergic Resources Corporation performed a second screening to add a number of case study sites.

In order to be selected as a case study candidate, the cogeneration system had to satisfy the following requirements:

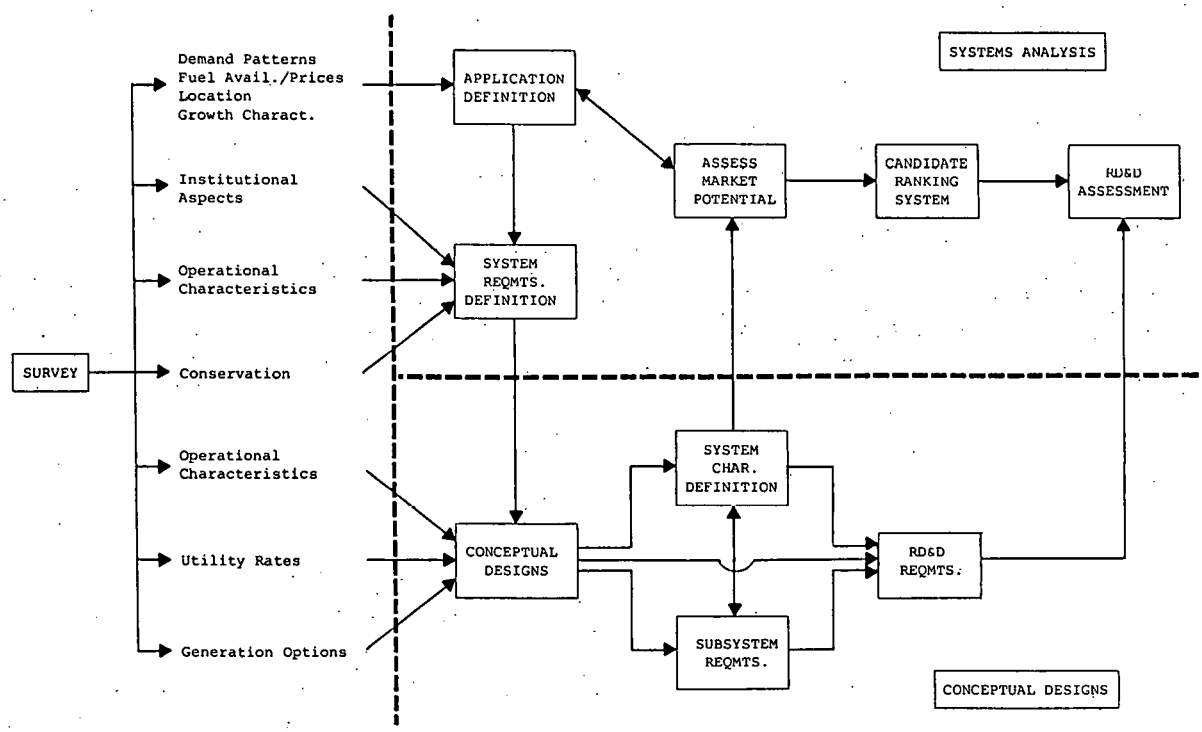


Figure 1. Conceptual Overview of Study Approach

- Currently operational.
- At least one year old.
- Electrical capacity of greater than 5 MW (preferably greater than 10 MW).
- Operational for at least 8 hours per day.
- Currently providing both electrical and thermal energy.
- In the industrial sector, preferably in the energy-intensive manufacturing industries.
- Willing to cooperate and provide data.

In addition, the candidates as a group were selected to represent a diversity of:

- Prime movers/thermodynamic cycles.
- Utility interface.
- Primary fuels.
- Ownership.
- Industrial groups (SIC).
- Geographic location.

A list of the selected case study candidates is given in Table 1. Figure 2 shows the location of these systems.

SUMMARY OF CASE STUDY RESULTS

The cogeneration systems described in this paper offer a diversity of ages, sizes, efficiencies, types of equipment, thermal-electric load ratios, fuels used, fuel costs, utility interfaces, and economic performances. Since cogeneration systems are designed for the industrial facility which they serve, it is not surprising that they tend to be unique in design. The one common quality they show is the ability to generate electricity more efficiently than is possible for a utility power plant by utilizing energy which would be wasted during conventional generation. Table 2 presents basic characteristics of the 17 cogeneration systems included in this survey.

UTILITY PERSPECTIVES

A survey of utility perspectives on industrial cogeneration was conducted with 11 utilities. (Some of the utility surveys were initially conducted by TRW, Inc.) These utilities shared with us the top level management attitudes and opinions which determine company policy in these matters. The survey examined:

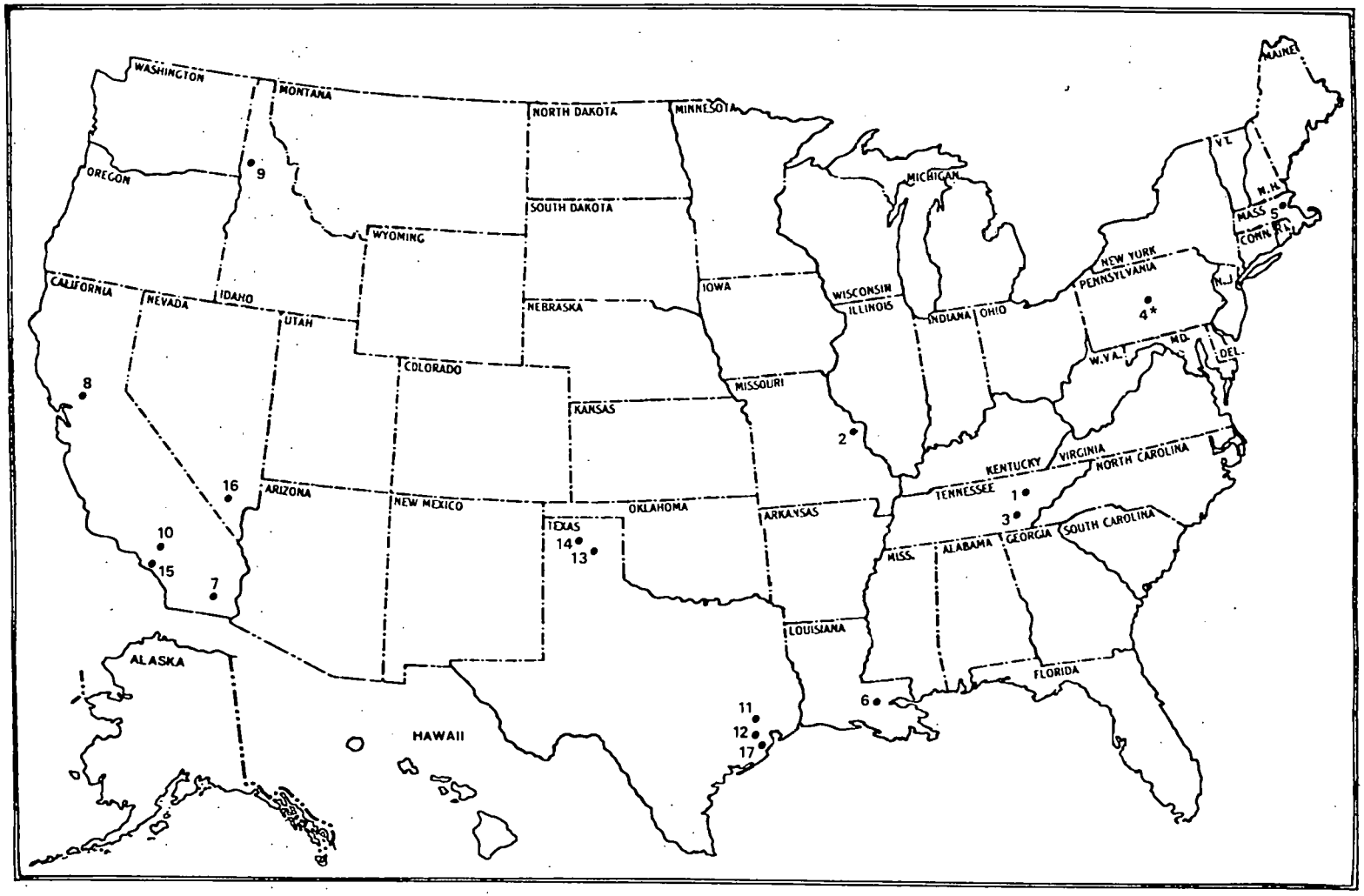
- General Operating Characteristics of the Utility, e.g., generating capacity, fuels used, expansion plans, etc.
- Current Involvement with Cogeneration, i.e., number of cogeneration plants in service area, industrial or utility ownership, and involvement in the assessment of additional facilities.
- Specific Utility Policy Toward Cogeneration, such as the existence of rate structures or tariffs, for stand-by service to cogeneration plants and/or purchase of excess power from cogenerators, etc.
- Overall Attitude and Policy toward cogeneration in each utility's service area.

Table 3 shows some of the general data on the utilities surveyed, including each utility's primary fuel(s), its projected growth rate through 1990, and the percentage of its kilowatt-hour sales which is represented by power purchased from the grid connections. These data are useful in assessing the utility fuels which would be displaced by additional cogeneration facilities. This is particularly relevant to the nation in terms of reducing our dependence on imported oil and limited resources such as natural gas, and to potential cogenerators

Table 1. List of Cogeneration Systems Studied

1. American Enka Company - Lowland, TN	10. Riverside Cement Company - Oro Grande, CA
2. Anheuser Busch, Inc. - St. Louis, MO	11. St. Regis Paper - Houston, TX
3. Bowater Southern Paper Corp. - Calhoun, TN	12. Shell Oil Company - Deerpark, TX
4. (Name Withheld)* - Pennsylvania	13. Celanese Chemical Co./Southwestern Public Service Co. - Pampa, TX
5. General Foods Corp. - Woburn, MA	14. Phillips Petroleum Co./Southwestern Public Service Co. - Borger, TX
6. Gulf States Utility Co. - Baton Rouge, LA	15. Southern California Edison - Pomona, CA
7. Holly Sugar Corp. - Brawley, CA	16. Stauffer Chemical Company - Henderson, NV
8. Pacific Gas and Electric Co. - Avon, CA	17. Union Carbide Corp. - Texas City, TX
9. Potlatch Corp. - Lewiston, ID	

*Due to confidentiality restrictions, the name of this company cannot be disclosed.



*Exact location disguised.

Figure 2. Location of Cogenerators Surveyed

Table 2. Characteristics of Cogeneration Systems Studied

NAME OF FIRM	1 YEAR COGENERATION BEGAN	2 YEAR LAST EXPANSION	3 ELECTRIC CAPACITY (MW)	4 ELECTRIC GENERATION (MILLION KWH)	5 UTILITY RELATIONS[a]	6 SYSTEM TYPE[b]	7 OPERATIONS MODE	8 FUELS USED	9 FUEL COST ($/10 Btu)	10 ELECTRIC PURCHASE COST (¢/KWH)
AMERICAN ENKA	1947	1960	20	88	PO	STT	Thermal, Electric	Coal	1.44	2.4
ANHEUSER BUSCH	1929	1951	27.6	72	PO	STT	Thermal	Coal, NG	2.25	NA
BOWATER SOUTHERN	1954	--	45	378	GI	STT	Thermal	Wood wastes, Oil, NG	1.00	2.5
(NAME WITHHELD)	1934	1948	11	65	PO	STT	Thermal	Oil	2.40	NA
GENERAL FOODS	1978	--	7.5	26	GI	STT	Thermal	NG	2.50	3.8
GULF STATES UTILITY COMPANY	1930	1954	190	1,078	GI	STT	Thermal	NG, Refinery Gas	2.60	--
HOLLY SUGAR	1949	1978	7.5	16	I	STT	Electric	NG	2.40	NA
PACIFIC GAS & ELECTRIC	1939	--	50	145	GI	STT	Thermal	NG, Refinery Gas	Proprietary	--
POTLATCH	1951	1977	20	102	PO	STT	Thermal	NG, Black Liquor	1.20	0.8
RIVERSIDE CEMENT	1954	--	15	126	GI	STB	Electric	Waste heat, Oil	(d)	3.75
ST. REGIS	1967	--	95	557	GI	Combined Cycle	Thermal	NG, Wood waste	1.15	2.3
SHELL OIL	1941	1979	60	342	PO	STT, GT	Thermal, Electric	Refinery Gas, NG	2.40	2.2
SOUTHWEST PUBLIC/ CELANESE[c]	1979	--	30	189	GI	STT	Electric	Coal	1.20	3.0
SOUTHWEST PUBLIC/ PHILLIPS	1966	--	33	NA	GI	GT	Electric	NG	2.40	3.0
SOUTHERN CALIFORNIA EDISON	1960	--	14.5	78	GI	GT	Electric, Thermal	NG, Oil	Proprietary	--
STAUFFER CHEMICAL	1968	--	27	180	PO	Combined Cycle	Thermal	NG	2.70	2.9
UNION CARBIDE	1941	1967	70	386	PO	STT, GT	Thermal	NG	2.50	2.8

See Footnotes at end of Table.

Table 2 (Continued). Characteristics of Cogeneration Systems Studied

NAME OF FIRM	11 CAPACITY FACTOR	12 SYSTEM EFFICIENCY	13 ALPHA VALUE Btu(e)/ Btu(t)[e]	14 NET HEAT RATE Btu/KWH	15 DEMAND MET BY COGENERATION (%) THERMAL	16 DEMAND MET BY COGENERATION (%) ELECTRICAL	17 AVAILABILITY (%)	18 UNSCHEDULED OUTAGES (hrs/yr)	19 FUEL COST THERMAL ($/10^6 Btu)[f]	20 FUEL COST ELECTRIC (¢/KWH)[g]
AMERICAN ENKA	0.50	0.62	0.14	6,430	100	23	99.9	0	2.45	0.9
ANHEUSER BUSCH	0.30	0.77	0.11	5,600	100	41	99.9	0	2.86	1.3
BOWATER SOUTHERN	0.96	0.55	0.27	11,190	82	39	99+	0	1.43	1.1
(NAME WITHHELD)	0.67	0.76	0.12	5,750	100	71	99.9	0	3.06	1.4
GENERAL FOODS	0.40	0.73	0.15	7,650	62	100	85	0	3.16	1.8
GULF STATES UTILITY COMPANY	0.65	0.73	0.17	5,830	--	--	99.9	1	3.43	1.5
HOLLY SUGAR	0.24	0.70	0.10	7,550	73	100	99.9	0	3.32	1.9
PACIFIC GAS & ELECTRIC	0.33	0.57	0.30	9,400	--	--	99.9	NA	--	--
POTLATCH	0.58	0.64	0.03	5,700	82	23	95+	NA	1.86	0.7
RIVERSIDE CEMENT	0.96	(h)	(h)	11,320	0	87	99.9	NA	(d)	(d)
ST. REGIS	0.67	0.67	0.21	5,200	100	NA	99.5	48	1.72	0.6
SHELL OIL	0.65	0.76	0.07	4,500	NA	21	99.7	0	3.15	1.1
SOUTHWEST PUBLIC/ CELANESE[c]	NA	0.67	0.07	4,800	NA	NA	NA	NA	1.80	0.6
SOUTHWEST PUBLIC/ PHILLIPS	NA	0.70	0.48	7,030	NA	NA	99.9	0	--	1.7
SOUTHERN CALIFORNIA EDISON	0.61	0.65	0.34	6,630	--	--	94	NA	--	--
STAUFFER CHEMICAL	0.76	0.74	0.30	5,050	100	50	98	NA	3.51	1.4
UNION CARBIDE	0.63	0.68	0.08	6,600	100	100	99.9	NA	3.60	1.7

FOOTNOTES

[a] Utility Relations:

I - Isolated
PO - Parallel Operation
GI - Grid Interconnected

[b]
STT - Steam turbine topping cycle
STB - Steam turbine bottoming cycle
GT - Gas turbine topping cycle
STT, GT - Steam turbine and gas turbine operating in parallel
CC - Combined cycle, gas turbine exhaust used to produce steam for steam turbine

[c] Celanese numbers have been estimated from numbers given by utility.

[d] Riverside Cement utilizes waste heat -- no price could be assigned.

[e] Alpha value is the ratio of the Btu value of electricity generated to the Btu content of steam produced for process.

[f] Fuel Cost Thermal is the cost of the fuel needed per million Btu of process steam.

[g] Fuel Cost Electric is the cost of the fuel needed to generate 1 KWH of electricity.

[h] Riverside is bottoming cycle -- steam efficiency and alpha value not applicable.

ADDITIONAL ABBREVIATIONS:

NA - Not Available

NG - Natural Gas

Table 3. General Utility Data and Attitude Toward Cogeneration

Utility	Power Generation By Fuel Type, Thousand MWH (1978)	Projected Avg. Annual Growth Thru 1990	% of KWH Sales Purchased	No. of Existing Cogenerators	Preferred Ownership: I=Industry U=Utility	Overall Attitude Toward Cogeneration
Alabama Power Company	Coal 18,658 Nuclear 5,920 Hydro 3,139 Oil & Gas Negligible	Not available (positive)	17	19	Not available	Does not promote cogeneration
Baltimore Gas & Electric	Nuclear 9,702 Coal 3,719 Oil/Steam 1,940 Hydro 647 Gas & Oil 162	Not available (positive)	Not available (believed to be small)	3	I	Receptive to cogeneration proposals; does not promote; has established power purchase rates.
Boston Edison (1977 Data)	Oil 8,733 Nuclear 2,652 Gas 3	3.9%	5	More than 2	I	Receptive to cogeneration proposals but does not actively promote.
Commonwealth Edison	Nuclear 30,600 Coal 27,200 Gas 4,500	4.2%	3	10-12	I or U	Large nuclear & coal base provides low cost power which cogenerators must compete with
Delmarva Power & Light (1977 Data)	Oil 3,987 Coal 1,957 Nuclear 1,305	5.0%	1	1	U	Receptive to cogeneration proposals but for opportunities in service area
New England Power Service (1977 Data) [Subsidiary of New England Electric System]	Coal 11,116 Hydro 1,597 Pumped Storage Hydro 95 Gas & Oil 37	2.8%	12	1	I or U	Receptive to cogeneration proposals; does not promote
Pacific Gas & Electric	Oil & Gas 30,500 Hydro 13,480 Geothermal 2,970	3.5%	24	20	U	Actively promoting cogeneration via favorable rate structures
Pennsylvania Power & Light	Coal 24,167 Oil/Steam 6,426 Hydro 13,480 Gas & Oil 106	2.5-4%	Sales to power pool exceed 5 times purchases	8-9	I	Actively promoting cogeneration in order to defer power plant construction
Philadelphia Electric	Nuclear 7,769 Oil 7,174 Coal 6,690 Hydro 1,700	2.5%	23	12	I or U	Receptive to cogeneration proposals; does not promote
Southern California Edison	Oil 27,369 Gas 11,187 Coal 6,501 Hydro 5,888 Nuclear 2,127	3.5%	17	2	I	Actively promoting cogeneration via favorable rate structures
Tennessee Valley Authority	Coal 77,939 Hydro 20,694 Nuclear 15,795 Oil & Gas 2,940	2-4%	5	6	I	Actively promoting cogeneration in order to defer power plant construction

considering sale of excess power to a utility. In the past, if a cogenerator was using an expensive fuel, such as oil or gas, the utility may have been able to generate power cheaper (using coal, nuclear, or hydro), or to buy power from a pool more cheaply than from a cogenerator. Under these conditions, the utility would have been unwilling to buy power from the cogenerator. However, if by-product fuels, wood, or coal were used in cogeneration, or if a utility depended heavily on oil and gas generated power, cogenerators found utilities very willing to buy their excess power.

UTILITY CONCERNS REGARDING COGENERATION

All of the utilities surveyed, independent of their overall attitude, expressed some concerns about involvement with DEUS operations. These concerns are in a variety of areas, including:

- Reliability and maintenance of DEUS and the effects on the utility and its customers.
- Safety of interconnection equipment and utility personnel.
- Loss of customers and erosion of the utility's base load.
- Availability of pay-back power from industrial DEUS.
- Requirement for back-up capacity.
- Development of equitable rates from the viewpoints of the utility, its customers and the cogenerator.

In general, the utilities participating in the survey would all strongly favor DEUS in their service area if there was no reliability or safety question, if DEUS could be firm suppliers of power at a rate which would save the utility money, if they could gain exceptions from NEA to burn oil or gas, or get exceptions from emission standards to burn coal, and if there was no significant erosion of the utility's load base from conversions to DEUS. In the absence of this utopian scenario, some utilities still have favorable attitudes toward cogeneration (DEUS), though they and others, whose attitudes are less favorable, have legitimate concerns.

CONTINUING EFFORTS

Additional case studies of industrial cogeneration are currently underway.(8) Information from the case studies reported here, the DOE efforts, and other secondary data sources is being compiled in a Cogeneration Data Base for EPRI. The secondary sources examined include:

- FERC Form 1 where utilities report power purchased from industrial generators.
- FERC Form 4 in which industrial generators report type of generation, capacity and monthly generation.
- FERC Form 12 which report for a small number of industrial generators, detailed information on the generation facility.
- Filings by cogenerators to FERC for exemptions from incremental pricing.
- Other published data.

The Cogeneration Data Base is expected to be a continuing effort. Additional information will be available in Summer 1980.

Subsequent tasks of the EPRI DEUS program include:

- Analysis of cogeneration systems.
- Development and evaluation of alternative conceptual designs for cogeneration, including systems characteristics and subsystems requirements.
- Assessment of market potential, including an evaluation of how cogeneration systems would fit into the utility's optimum capacity expansion plan.
- Ranking and prioritization of cogeneration concepts.
- Assessment of future research, development and demonstration needs.

ACKNOWLEDGMENTS

The authors would like to acknowledge the assistance and support provided by Robert Mauro of EPRI during the performance of the case studies. We also want to express our appreciation and gratitude to the numerous industry personnel for their cooperation in providing the information for the case studies and their patience in answering numerous questions.

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THE ECONOMICS OF STEAM/ELECTRIC GENERATION

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ABSTRACT

The economics of combining steam and electric generation for companies requiring both steam and electric services develop a challenge which few engineers and economists can realize. This paper outlines the general approach to this challenge and the procedure for reaching an equitable solution. The approach uses a system of programs which meet both present and future requirements. Each program has different operating costs and capital investments spread over an extended period of time. Simple load growth procedures establish the future requirements and noncomputerized construction schedules guide the procedure to completion. Capital expenditures, by this approach, are established and are then combined with operating costs. The present worth system is then used to evaluate each program. This system is also adjusted to show the effect of inflation and other variables affecting the evaluation. This procedure allows each system to be summarized, with or without inflation, to assist management in reaching an equitable solution to the problem.

INTRODUCTION

Conservation of energy in the area of steam and electric generation continues to become an advantage in both energy conservation and economic reality where the services of both electric and steam generation can be made available.

This paper sets up some parameters, based on a steam supply study conducted for the Board of Water & Light, Lansing, Michigan, to assist engineers in approaching the problem of attaining energy conservation and maintaining economic reality. It should be realized that each problem is a separate entente and approaches must be adjusted to meet the specific problem.

PROGRAMS CONSIDERED

To provide additional steam load growth for the Board of Water & Light, seven programs were considered. They are:

Program A: Increase the capacity of the steam distribution system by supplementing the present system with a new 18 inch steam main starting at Grand Avenue and Lenawee Street, and running to the Moores Park Plant. Capital cost is estimated at $2,992,000 escalated to 1979.

Program D-1: Install in the Moores Park Plant area, two 400,000 PPH boilers operating at 1300 psig, 950°F, and a 50 MW noncondensing turbine-generator, together with all auxiliaries, and a new 600 foot chimney. The turbine would exhaust at 270 psig into the steam mains. Capital cost is estimated at $93,497,000 escalated to 1983.

Program D-4: Install a pressure reducing and desuperheating station, and water treatment system at the Ottawa Street Station, in-service for the heating season of 1980-1981. Capital cost is estimated at $2,470,000.

Program F: Install in the Moores Park Plant area, a 50 MW noncondensing turbine-generator operating at 1300 psig, 950°F, obtaining its steam supply from the Eckert Station, together with all auxiliaries. The turbine would exhaust at 270 psig into the steam mains. Capital cost is estimated at $25,381,600 escalated to 1983.

Program F-1: Install in the Moores Park Plant area, a 50 MW condensing, automatic extraction turbine-generator operating at 1300 psig, 950°F, obtaining its steam supply from the Eckert Station, together with all auxiliaries. The turbine would exhaust at 270 psig into the steam mains, but when steam is not required for the steam system, the turbine could act as a condensing unit, making available to the electric system an additional 50 MW. Capital cost is estimated at $30,694,400 escalated to 1983.

Program G: Install in the Moores Park Plant area, two 350,000 PPH boilers and a 44 MW noncondensing turbine-generator, together with all auxiliaries and a new 600 foot chimney. The turbine would exhaust at 270 psig into the steam mains. Capital cost is estimated at $87,109,000 escalated to 1984.

Program G-1: Install in the Moores Park Plant area, two 350,000 PPH boilers and a 44 MW condensing automatic extraction turbine-generator operating at 1300 psig, 950°F, together with all auxiliaries. A new 600 foot chimney is included. The turbine would exhaust at 270 psig into the steam mains, but when steam is not required for the system, the turbine could act as a condensing unit, making available to the electric system an additional 44 MW. Capital cost is estimated at $92,300,400 escalated to 1984.

BASIS OF REPORT

The following criteria were used as a basis for the Board of Water & Light project:

1) Annual load growth and projected peak steam demand of the system were supplied by the Heating Division of the Board of Water & Light for the years 1976 to 1990.

2) Coal cost was supplied by the Board of Water & Light at a price of $57.79 per ton for the Ottawa Street Station and $45.51 per ton for the Moores Park Plant and Eckert Station, based on sulfur contents of one percent or less, as now being used. The BTU value of the coal is 13,500 BTU per pound.

3) Cost of operation when firing coal was based on a boiler efficiency of 87.7 percent.

4) All programs were based on meeting the present air and water pollution requirements of the Michigan Department of Natural Resources.

5) No condensate return was included in the evaluation, as all of the condensate from the distribution system was lost.

6) Construction costs used in the estimates were based on data supplied by manufacturers, data available from past installations and recent installations.

7) Labor costs were based on labor rates in the Lansing, Michigan area.

8) Power plant labor and supervision costs were based on manning data supplied by the Board of Water & Light's Operating Department.

9) Maintenance and material costs were based on .07 cents per dollar of coal costs when firing coal. Services and supplies were based on .007 cents per dollar of coal cost when firing coal.

10) Electric power costs were supplied by the Board of Water & Light, based on present day costs.

11) Capital cost estimates were based on 1976-1977 costs escalated at 10 percent per year compounded to the date that the installation will be completed and in-service. No other figures, including labor, fuel cost, outside services and other costs have been escalated.

12) Operating costs were established, based on steam generation. Credit has been allotted to any program for the electric power generated during the time that steam would be supplied to the steam system, based on coal cost only.

13) The condensate make-up system was based on 100 percent make-up.

14) No capital cost advantage or disadvantage for electric system operation was considered in the comparison of the programs.

15) Economic evaluations were based on a 10 percent level fixed-charge rate as per the Board of Water & Light.

16) A 6.5 percent discount rate was used in calculating the present worth of future expenses as per the Board of Water & Light.

17) The gross heat rate for Units 1, 2 and 3 at the Eckert Station, was 10,700 BTU per kWh, as supplied by Board of Water & Light.

18) Estimated gross heat rate of the units used in the study with extraction operation was approximately 5,500 BTU per kWh.

19) Estimated gross heat rate of the units used in the study without extraction operation was approximately 11,500 BTU per kWh.

EVALUATION OF PROGRAM

After the scope of work and the basis of report have bee established, load growth and peak demand curves should be established. (See Figures 1 and 2.)

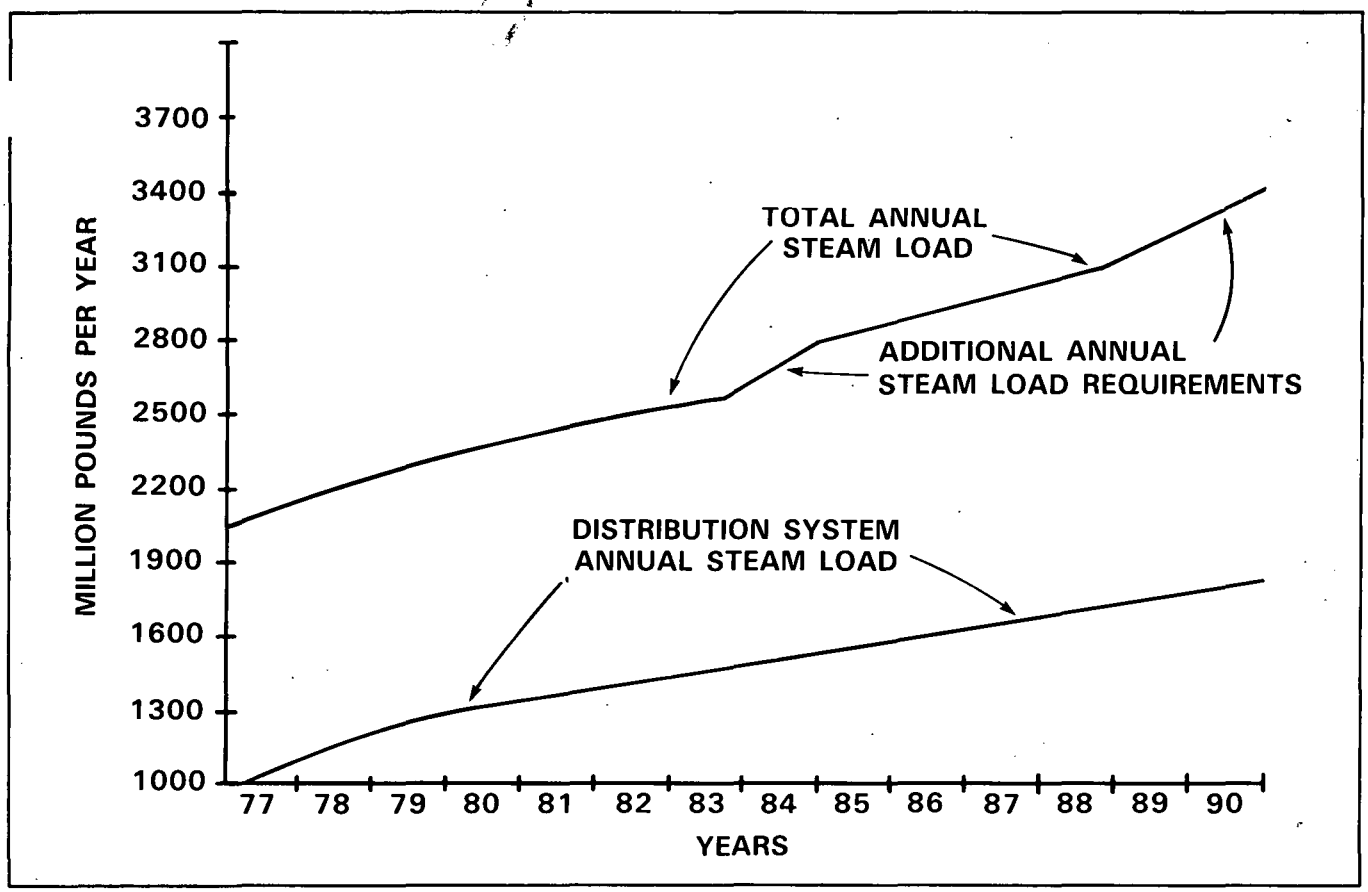
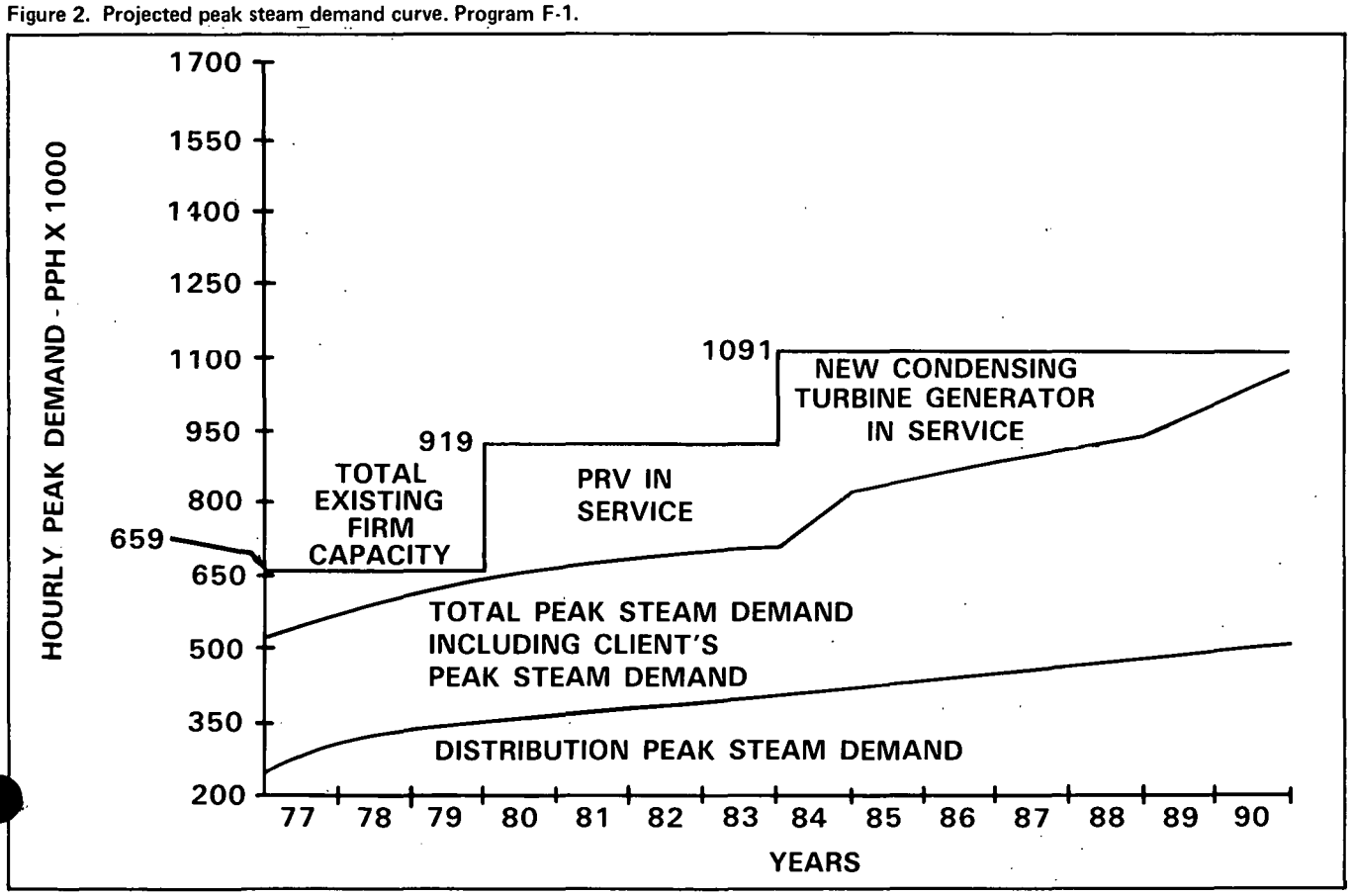


Figure 1. Projected annual steam load curve.

Figure 2. Projected peak steam demand curve. Program F-1.



In order to cover the topic in greater detail, only one of the programs will be followed to completion in this paper. For the Board of Water & Light study, the other programs were handled using the same approach.

Prior to preparing cost estimates and operating costs, it is necessary to prepare siting and layout drawings. These drawings can be general, showing the size of building and the arrangement of equipment such as steam generators, turbine-generators, coal bunkers and any other major equipment which will require space for handling and operation. (Field investigation and inspections will be required to establish these parameters.) These siting and layout drawings will then be used for the basis of the cost estimate which, in turn, will allow development of evaluations.

The Board of Water & Light siting and layout drawings are shown in Figures 3, 4, 5 and 6.

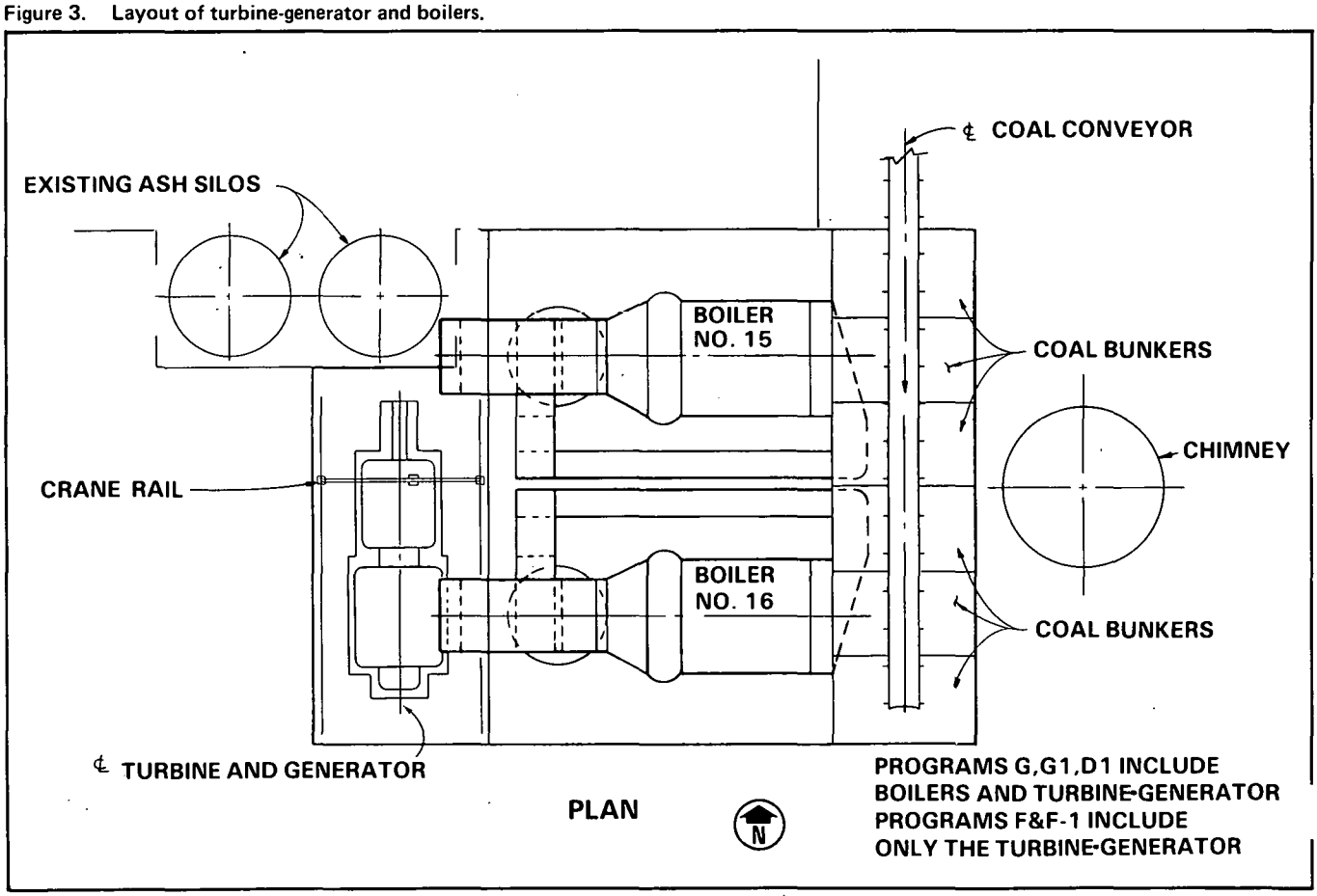
The installation cost estimate was prepared from information received from manufacturers. This was combined with mechanical, structural, electrical and architectural requirements to establish a cost estimate for each program. The contingencies were then set at 10 percent of the estimated cost, based on field investigations and other necessary items. Due to delivery of equipment and the necessity to provide steam supply until the new program would go in-service, costs were escalated for five years at 10 percent per year compounded. (See Table I.) The peak demand curve and the construction schedule as shown in Figures 2 and 7 established the timing for the in-service data and construction program.

Total operating costs included fuel rates, maintenance and materials, service and supplies, supervision and labor, and electric power. Close coordination with a client's operating department is needed in order to obtain a realistic figure for these items, particularly with reference to labor man-hours, maintenance and materials, and services and supplies. Costs for this particular program are shown on Table II.

Maintenance and material costs and service and supplies costs were established from experience and cost records available over a long period of time for pulverized fuel firing. The per dollar of coal cost figure is $.07 for maintenance and materials, and $.007 for service and supplies.

Having established capital and operating costs, and scheduled expenditures, the facts can be evaluated. This can be done in a number of ways. The two systems generally in use are "percent return on the additional capital expenditure" and "present worth". This paper uses the present worth method.

Figure 3. Layout of turbine-generator and boilers.



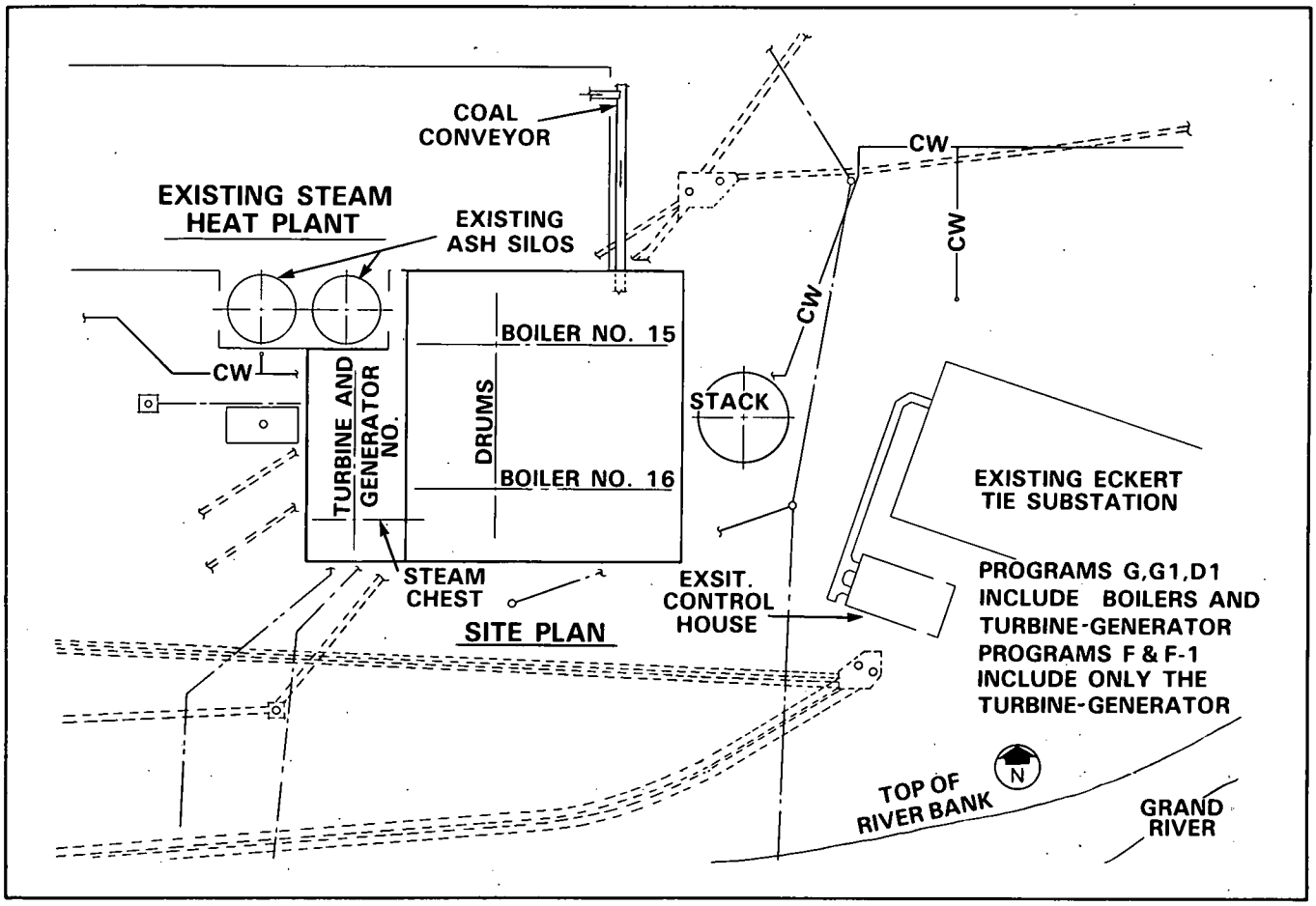


Figure 4. Site plan.

Table III, which is not the chosen program presented in this paper, shows a present worth of revenue required for the years 1977-1990 to be $115,225,000. Now, referring to the program outlined in this paper and to Table IV, the equivalent present worth of revenue required is $91,368,000. This makes a difference of $23,857,000 in favor of the program outlined in Table IV.

With this type of report, management can make relatively straight forward decisions. The report provides detailed data, as well as engineering recommendations that the program considered have the lowest present worth of revenue required, based on a fixed-charge rate and a discount rate. Investigations of this type are very interesting to make and provide a challenge which will afford valuable experience in engineering and management.

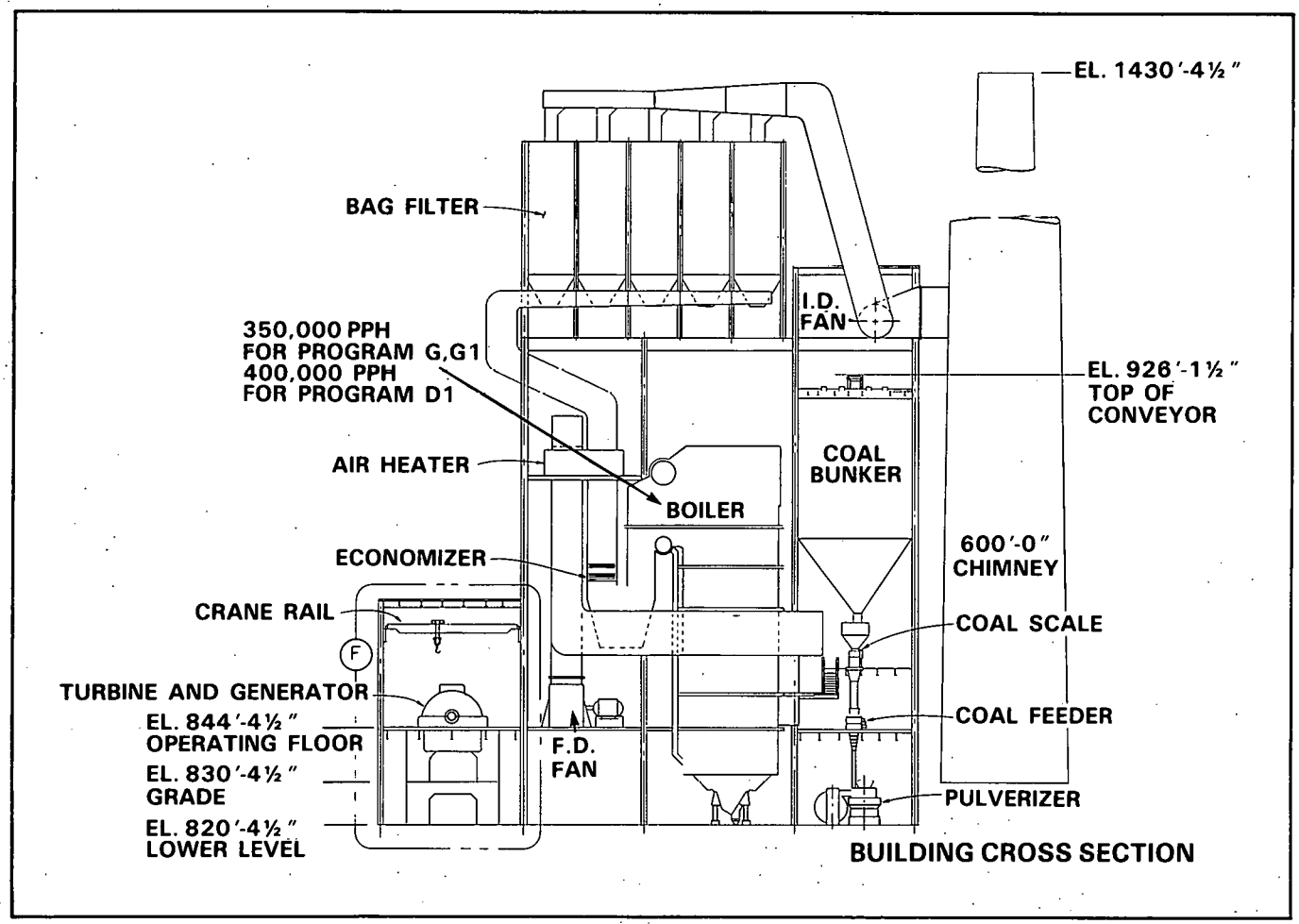


Figure 5. Cross-section of building.

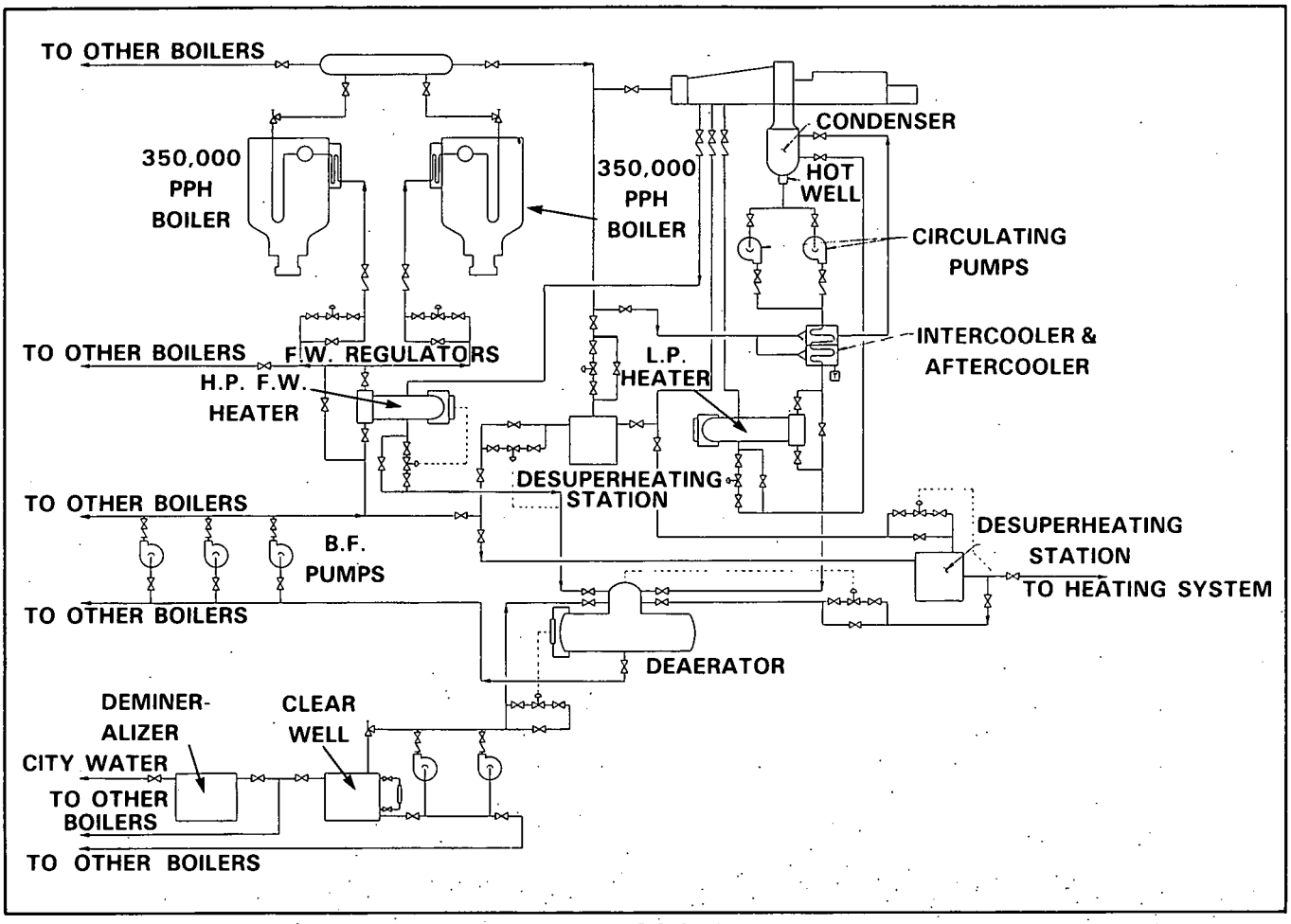


Figure 6. 44 MW turbine-generator condensing automatic extraction @ 270 psig.

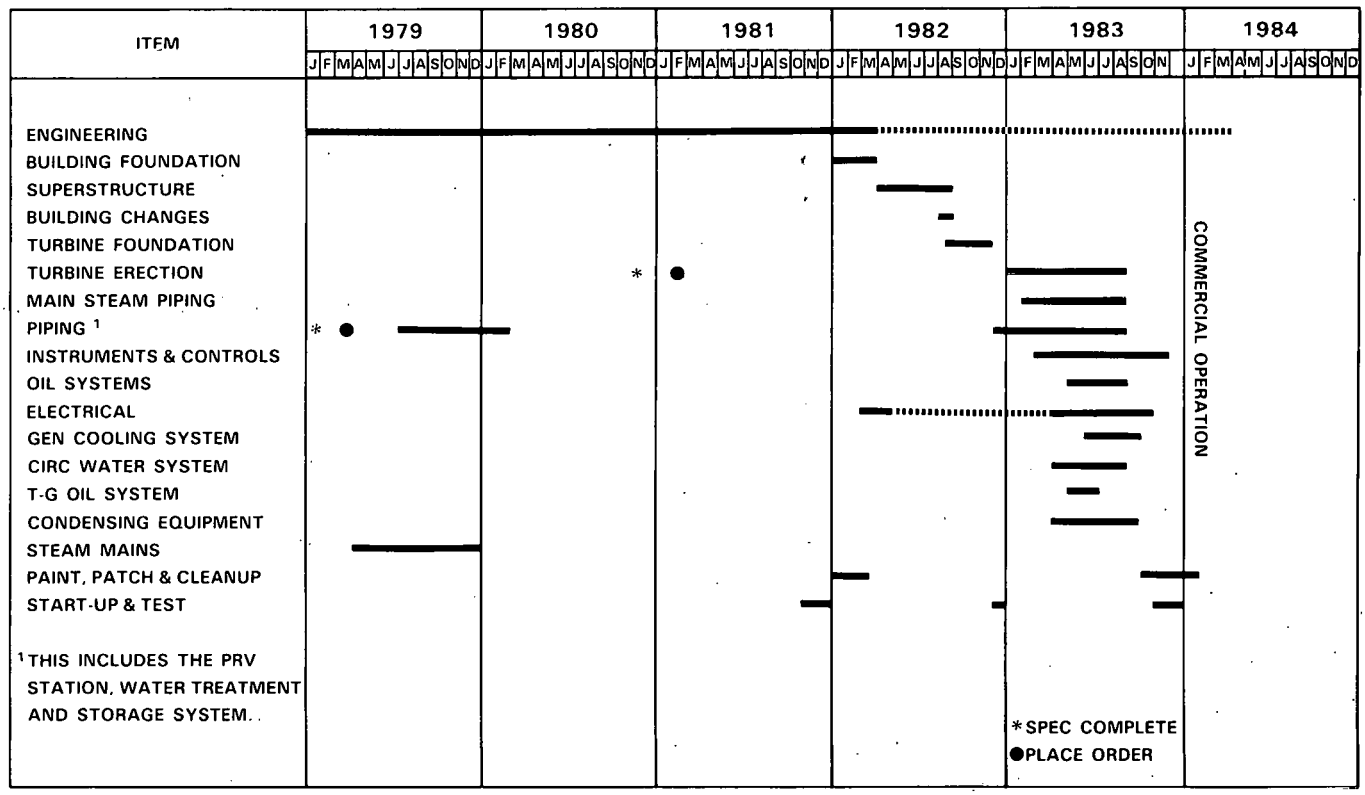


Figure 7. Program F-1, engineering and construction schedule.

TABLE I
BOARD OF WATER AND LIGHT
STEAM SUPPLY STUDY
MOORES PARK STATION
COST ESTIMATE
PROGRAM F-1

(Install 1-50 MW condensing turbine-generator in new building at Moores Park. Steam supply from Eckert Station. In-Service 1984.)

A.	Program D-4 In-Service 1980 (Escalated to 1980)	$2,470,000
B.	Steam Mains In-Service 1980 (Escalated to 1980)	2,992,000
	Total	$5,462,000
	1-50 MW Condensing Automatic Extraction Turbine-Generator	$5,900,000
	Erection	415,800
	Generator Cooling System	55,000
	Turbine-Generator Oil System	38,000
	Foundation	635,600
	Building, Crane, Steel, Walls, Floors	865,000
	Building Changes	30,000
	Instruments & Controls	130,000
	Piping, Valves & Insulation	1,040,000
	Accessory Electric	935,000
	Feedwater Treatment	1,260,000
	Condensing Equipment, Delivery & Erection	450,000
	Circulating Water System	310,000
	Feedwater Heaters	175,000
	Water Storage Tank	80,000
	Paint Patch & Clean-Up	80,000
	Subtotal	$12,399,400
	Contingencies	1,239,940
		$13,633,340
	Engineering	1,190,000
	Construction Supervision	838,000
		$15,667,340
	With 5 years of Escalation at 10% Per Year Compounded	$25,232,400
	Total of A & B Above	5,462,000
	Total	$30,694,400

TABLE II

BOARD OF WATER AND LIGHT
STEAM SUPPLY STUDY
OPERATING COSTS
PROGRAM F-1

(Install 50 MW Condensing Turbine-Generator at Moores Park with Steam Supply from Eckert Station. In-Service 1984)

ITEM	1977		1990
Total Steam Generation x 10^6 PPY	2496.7		3821.3
Steam Generation			
Ottawa Station x 10^6 PPY	417.1		167.1
Moores Park Station x 10^6 PPY	2079.6		128.1
Eckert Station x 10^6 PPY	0		3526.1
Heating Fuel (Tons)			
Ottawa Street	19,899	1978-1989	10,079
Moores Park	103,677		6,386
Eckert	0		177,288
Generating Fuel (Tons)	0		36,961
KWH Generated	0		119,745,092
Fuel Costs			
Ottawa Street	$1,149,963		$ 582,465
Moores Park	$4,718,340		$ 290,627
Eckert	0		$ 9,750,501
Maintenance and Material			
Ottawa Street	$ 80,479		$ 40,773
Moores Park	$ 330,284		$ 20,344
Eckert	0		$ 682,535
Supplies and Services			
Ottawa Street	$ 8,050		$ 4,077
Moores Park	$ 33,028		$ 2,034
Eckert	0		$ 68,254
Supervision and Labor			
Ottawa Street	$ 850,650		$ 283,550
Moores Park	$ 421,045		$ 275,000
Eckert	0		$ 200,000
Additional Electric Power			
Eckert	0		$ 40,051
TOTAL	$7,591,857		$ 12,240,211
CREDIT FOR ELECTRICAL GENERATING FUEL COSTS	0		$ – 1,682,124
NET OPERATING COSTS	$7,591,857		$ 10,558,087

TABLE III
BOARD OF WATER AND LIGHT
STEAM SUPPLY STUDY
ANNUAL REVENUE REQUIREMENTS

(Install 2-400,000 PPH boilers and a 50 MW condensing turbine-generator at Moores Park.)

Estimated Capital Investments: 1980 $5,462,000
1984 88,035,000

(Thousand of Dollars)

Year	Fixed Charges (a)	Annual Operating Costs	Total Annual Revenue Required	Present Worth Factor (b)	Present Worth of Revenue Required
1977	0	7,592	7,592	.939	7,129
1978	0	7,909	7,909	.882	6,976
1979	0	8,083	8,083	.828	6,693
1980	546	8,256	8,802	.777	6,839
1981	546	8,801	9,347	.730	6,823
1982	546	8,987	9,533	.685	6,530
1983	546	9,168	9,714	.644	6,256
1984	9,350	9,319	18,669	.604	11,276
1985	9,350	9,488	18,838	.567	10,681
1986	9,350	9,689	19,039	.533	10,148
1987	9,350	9,891	19,241	.500	9,621
1988	9,350	10,079	19,429	.470	9,132
1989	9,350	10,476	19,826	.441	8,743
1990	9,350	10,887	20,237	.414	8,378
TOTAL	67,634	128,625	196,259		115,225

a) Based on a 10% level fixed charge rate

b) Based on a 6.5% discount rate

TABLE IV
BOARD OF WATER AND LIGHT
STEAM SUPPLY STUDY
ANNUAL REVENUE REQUIREMENTS
PROGRAM F-1

(Install 50 MW condensing turbine-generator at Moores Park with steam supply from Eckert Station.)

Estimated Capital Investments (a): 1980 $ 5,462,000
1984 $25,232,400

(Thousand of Dollars)

Year	Fixed Charges (b)	Annual Operating Costs (c)	Total Annual Revenue Required	Present Worth Factor (d)	Present Worth of Revenue Required
1977	0	7,592	7,592	.939	7,129
1978	0	7,909	7,909	.882	6,976
1979	0	8,083	8,083	.828	6,693
1980	546	8,256	8,802	.777	6,839
1981	546	8,801	9,347	.730	6,823
1982	546	8,987	9,533	.685	6,530
1983	546	9,168	9,714	.644	6,256
1984	3,069	8,433	11,502	.604	6,947
1985	3,069	9,062	12,131	.567	6,878
1986	3,069	9,269	12,338	.533	6,576
1987	3,069	9,482	12,551	.500	6,276
1988	3,069	9,677	12,746	.470	5,991
1989	3,069	10,111	13,180	.441	5,812
1990	3,069	10,558	13,627	.414	5,642
TOTAL	23,667	125,388	149,055		91,368

a) From Table I
b) Based on a 10% level fixed charge rate
c) From Table II
d) Based on a 6.5% discount rate

ECONOMIC EVALUATION OF BY-PRODUCT POWER/CO-GENERATION SYSTEMS FOR INDUSTRIAL PLANTS WITH FLUIDIZED-BED COAL-BURNING FACILITIES

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ABSTRACT

Economic analysis of the construction and operation of by-product electric power and steam/power co-generation systems in coal fired fluidized-bed steam cycles, located at individual industrial sites analyzed by the author, is being presented. The plants analyzed employ fluidized bed boilers for generation of steam for process and building/heating/cooling demands, in conjunction with electric power co-generation. Results of the analysis are presented, using life cycle costs and investment payback periods, pinpointing the areas, type and magnitude of costs which should be considered in the selection of combustors or systems. Capital and operating costs, and recognized technical and economic barriers are also presented and their effects indicated. Life cycle cost of each of the alternatives analyzed are compared and the expected payback periods for the different size FBC plants and for different annual average production levels are discussed.

BACKGROUND

Detailed engineering study was performed evaluating the application of steam/electric power co-generation systems with fluidized bed combustors (FBC), as a means of burning high and low quality coals and other types of fuels in an environmentally acceptable manner. The study addresses six independent facilities currently furnished with steam from oil/natural gas burning central steam generating plants. The existing central steam plants at the facilities analyzed were built during the last ten to 27 years.

Based on the findings of the economic evaluation, sufficient information was provided to enable corporate management to assess steam and power co-generation with the use of coal and FBC technology as an alternative thermal energy source to increasingly scarce and expensive petroleum and natural gas fuels. Observations were made during the investigation and evaluation, to determine required modifications to existing systems and equipment, in order to permit the burning of coals with 1.5% or higher sulfur content in compliance with applicable air pollution standards and regulations. Technical and economic feasibility, using life cycle cost method was analyzed and evaluated in detail.

The facilities analyzed and compared were located in five different states, ranging from Northeast to Midwestern U.S.A., with peak heat and power production capabilities and plant capacities, as shown in Table 1.

Projected 1985 annual steam and electric power production of the facilities analyzed are the following:

Site No.	Projected Steam Production(*)		Projected Power Production(**)	
	Annual Production	Year-Round Average	By-Product Power	Co-Generation
1	612×10^6/yr	70×10^3/hr	21.9×10^6 kwh	31.6×10^6kwh
2	884×10^6/yr	101×10^3/hr	37.4×10^6 kwh	48.7×10^6kwh
3	840×10^6/yr	96×10^3/hr	31.6×10^6 kwh	41.9×10^6kwh
4	540×10^6/yr	62×10^3/hr	23.3×10^6 kwh	33.0×10^6kwh
5	568×10^6/yr	65×10^3/hr	24.0×10^6 kwh	33.6×10^6kwh
6	620×10^6/yr	71×10^3/hr	21.1×10^6 kwh	30.0×10^6kwh

(*) Steam production for condensing power generation not included
(**) Based on 7500 hrs/year generator operation

BY-PRODUCT POWER, STEAM/POWER CO-GENERATION FACILITIES

Basic Plant Concept

Since six independent facilities were studied simultaneously for FBC coal conversion, a "standardized" conceptual FBC plant design was developed for five different capacities, to meet future requirements of the sites. Three FBC alternatives, or variations of the "standard" plant, were evaluated for each site. These alternatives were the following:

1. FBC steam generation only.
2. Steam and by-product electric power generation.
3. Steam and electric power co-generation at about 50% of the projected future peak electric demand.

Turbine generator capacities were selected to produce by-product or co-generated power for the alternatives. Plant steam and electric capacities were selected as indicated in Table 2. Figure 1 depicts a general plan of the standardized FBC plant developed for this evaluation. Transverse section of the plant is shown in Figure 2. These figures show general features of each plant alternative.

TABLE 1

PLANT CAPACITIES AND PEAK DEMANDS

Location	Existing Plant Capacity	Current Peak Demand	Projected Peak Demand	Future Boiler Capacity	Future Power Generation Capacity By-Product Power	Co-Generation
1	225,000 lbs/hr	175,000 lbs/hr	250,000 lbs/hr	3-125,000 lbs/hr	6,500 kW	14,000 kW
2	165,000 lbs/hr	156,000 lbs/hr	300,000 lbs/hr	3-150,000 lbs/hr	7,000 kW	20,000 kW
3	240,000 lbs/hr	220,000 lbs/hr	280,000 lbs/hr	3-140,000 lbs/hr	7,000 kW	18,000 kW
4	178,000 lbs/hr	120,000 lbs/hr	150,000 lbs/hr	3- 75,000 lbs/hr	5,000 kW	10,000 kW
5	140,000 lbs/hr	100,000 lbs/hr	150,000 lbs/hr	3- 75,000 lbs/hr	5,000 kW	10,000 kW
6	240,000 lbs/hr	180,000 lbs/hr	200,000 lbs/hr	3-100,000 lbs/hr	6,000 kW	12,000 kW

TABLE 2

STANDARD FBC BOILER PLANT
SELECTED BOILER AND TURBINE-GENERATOR CAPACITIES

ALTERNATE	SIZE 1	SIZE 2	SIZE 3	SIZE 4	SIZE 5
Steam Generation Only Boiler Steam Pressure @ Site Requirement	3-75,000 lb/hr boilers	3-100,000 lb/hr boilers	3-125,000 lb/hr boilers	3-140,000 lb/hr boilers	3-150,000 lb/hr boilers
Steam Generation @ 1350 psig/950°FTT with By-Product Power Generation (Back Pressure Turbine-Generator)	3-75,000 lb/hr boilers 1-5000 KW_e Turbine/ Generator	3-100,000 lb/hr boilers 1-6000 KW_e Turbine/ Generator	3-125,000 lb/hr boilers 1-6500 KW_e Turbine/ Generator	3-140,000 lb/hr boilers 1-7000 KW_e Turbine/ Generator	3-150,000 lb/hr boilers 1-7000 KW_e Turbine/ Generator
Steam Generation @ 1350 psig/950° FTT with 50% of Peak Cogeneration (Extraction/Condensing Turbine-Generator)	3-75,000 lb/hr boilers 1-10,000 KW_e Turbine/ Generator	3-100,000 lb/hr boilers 1-12,000 KW_e Turbine/ Generator	3-125,000 lb/hr boilers 1-14,000 KW_e Turbine/ Generator	3-140,000 lb/hr boilers 1-18,000 KW_e Turbine/ Generator	3-150,000 lb/hr boilers 1-20,000 KW_e Turbine/ Generator

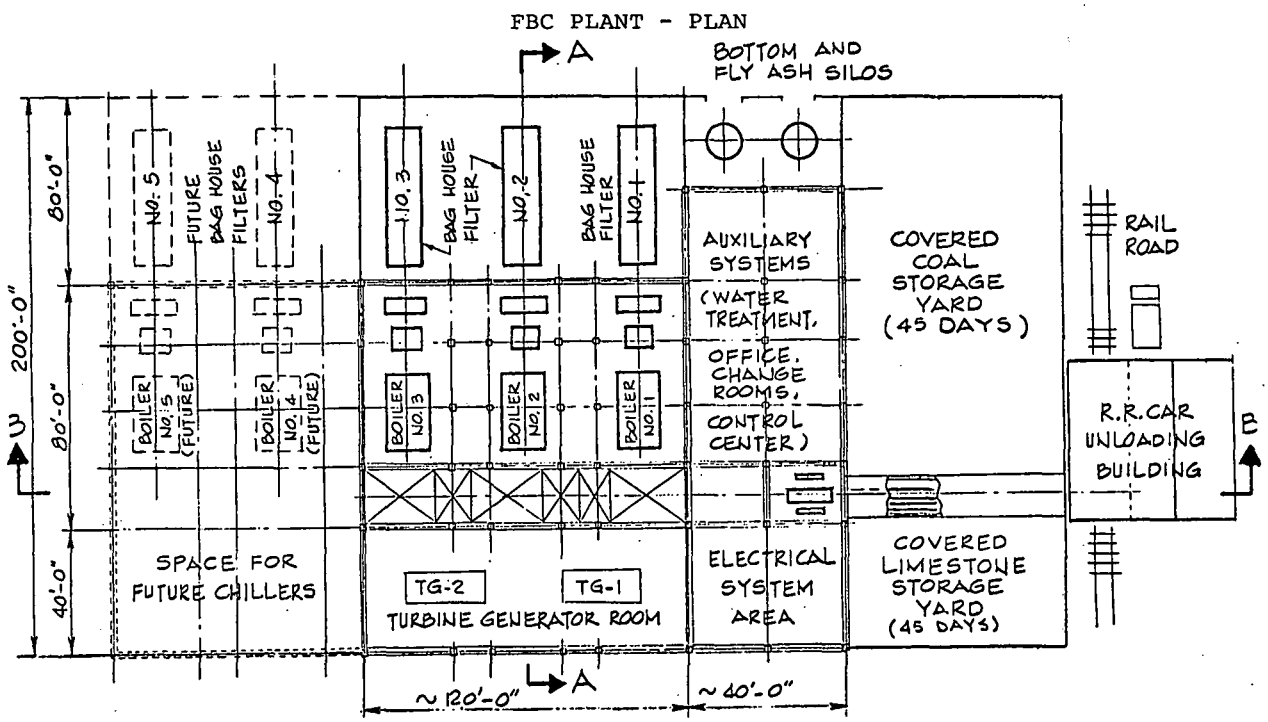


Figure 1

Coal Burning FBC Technology - Fluidized bed coal combustion technology is relatively new. The development of FBC boilers on a commercial scale has been achieved as a result of programs conducted by the U.S. Department of Energy and others.

The fluidized bed boiler plant is similar to a conventional coal fired plant, with major exception of the boiler design and the additional limestone

FBC PLANT - GENERAL ARRANGEMENT
CROSS SECTION

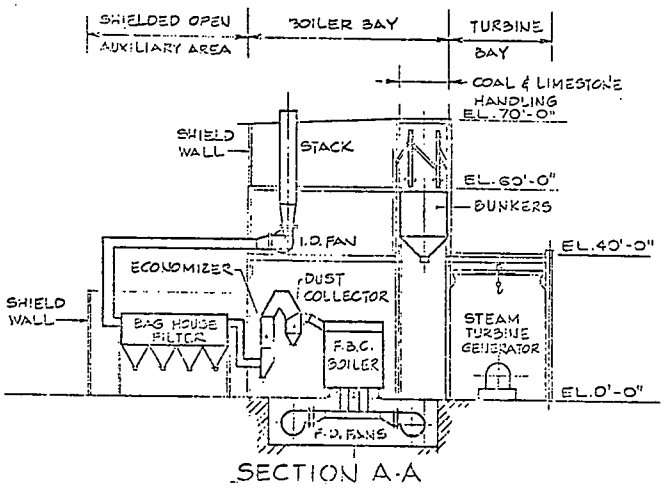


Figure 2

storage, handling and feed systems. Bed material removal, handling and storage is much the same as bottom ash handling, except the volume of solid is greater.

Thermal efficiency of the FBC considered was approximately the same as a stoker fired boiler with a grate. Coal usage is, therefore, the same, and coal is introduced either in the same manner as the standard stoker unit, or pneumatically blown into the bed. About one day usage is stored directly above the boiler in bunkers or bins.

Limestone, the sulfur dioxide sorbent, is a sized, dry product that can be transported via pneumatic conveyor system. It is stored in bunkers above the boiler room with approximately one day storage at each boiler.

Steam Generation - The basic plant considered would supply thermal requirements of the individual site. Three FBC boilers are provided in the basic plant concept. Each boiler is sized for 50% of the projected 1985 peak steam demand, the third boiler is a standby unit. Steam would be generated at the pressure of the existing steam distribution network.

The "standard" plant also allows for a program of phased implementation if this is desired. For example, a plant could be constructed with two FBC boilers and the existing plant used temporarily for standby duty. Another possibility is installation of high pressure superheated steam generating boilers, with pressure reduction and de-superheaters, and future installation of turbine generators and associated auxiliaries. As the general plant plan depicts, additional boiler capacity could also be added, as required, to meet load increases, during long term future plant expansion.

Pollution Control - The major inherent advantage of fluidized bed coal combustion is that inexpensive, high sulfur coal can be burned in compliance with applicable environmental standards without complicated sulfur scrubbers. Stack emissions are controlled in two ways:

1. Sulfur dioxide (SO_2) emissions are reduced by about 90% capture in the limestone bed during combustion.

2. Particulate emissions are controlled through the use of a baghouse. The baghouse filters 99+% of the particulate out of the flue gases.

Construction Schedule - It is important to note that if a decision to proceed was made, at least 48 months lead time would be required for a coal fired by-product power/co-generation plant before boiler lightoff. Actual construction work at these sites would require about 27 months.

Steam and By-Product Power Generation

Inexpensive electric power can be generated as a by-product of supplying steam to meet the thermal energy requirements of a facility. High pressure boilers are installed, generating super-heated steam (for example: 1350 psig @ 950°FTT). This high pressure, high temperature steam is passed through a back-pressure (non-condensing) turbine. The turbine exhausts at the steam pressure required for the facility steam distribution network. Electric output is proportional to facility steam demand at any moment in time. The power produced is less expensive than purchased power, due to the low electric generation/heat ratio. Steam passing through the back pressure turbine gives up its high grade thermal energy to electric generation. Remaining lower grade energy at the turbine exhaust is then fully utilized for heating and process needs. Therefore, the higher the pressure and temperature of the steam entering the turbine, and the lower the exhaust pressure and temperature, the more electric power can be generated for a given steam cycle. Turbine efficiencies used for the purpose of the evaluation were in the 70% range. A simplified schematic flow diagram of the steam by-product power generation system is present in Figure 3.

BY-PRODUCT ELECTRIC POWER GENERATION
SIMPLIFIED SCHEMATIC FLOW DIAGRAM

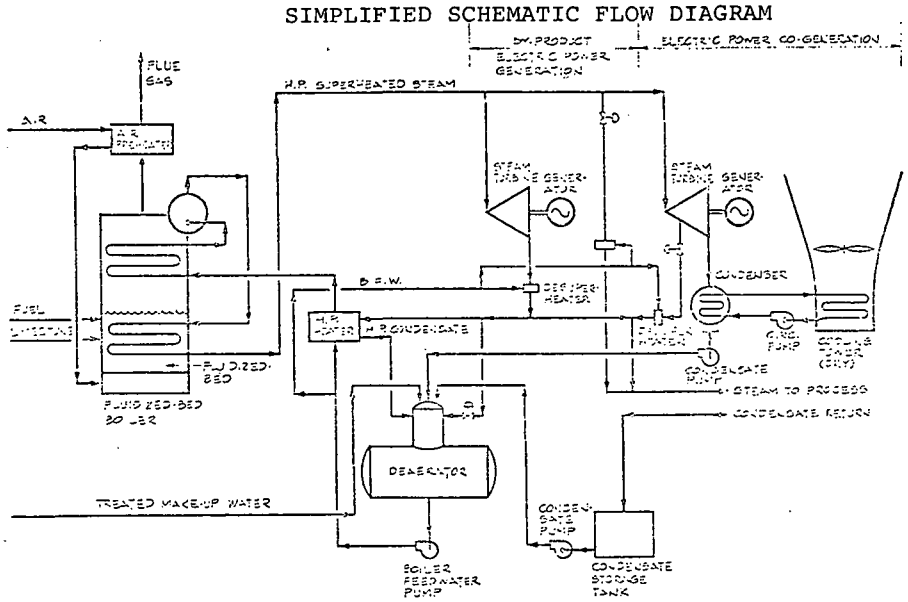


Figure 3

Aside from incorporation of high pressure boilers and back pressure turbine generator, other FBC steam plant systems are similar to the basic steam only plant. Again, the standard plant design allows for addition of boilers and another turbine generator to meet future growth needs.

Steam and Power Co-Generation

Larger electric generation capability can be incorporated in the planning design with the use of an extraction/condensing turbine generator. With a condensing turbine section in the cycle, power generation is no longer limited by the steam demand of the facility, but is only a function of boiler capacity and turbine size. A simplified schematic diagram of the extraction/condensing cycle is also shown as a portion of Figure 3.

ECONOMIC ANALYSIS

Methodology

A justifiable economic comparison and evaluation of the relative merits of energy investment alternatives can be performed using life cycle cost (LCC) analysis. The techniques are actively promoted by the U.S. Department of Energy and other government agencies. Using life cycle cost technique, the analysis performed for each location covers one oil and three FBC coal burning plant alternatives. These alternatives are sized to meet the projected 1985 steam needs, optimum by-product power generation level and 50% mand level power co-generation of each site. The alternatives can be summarized as:

1. Maintenance of status quo, that is, continuing operation with oil/natural gas firing and boiler replacement and/or plant expansion, as required. All power purchased.

2. Construction of a new coal fired FBC steam plant. All power purchased.

3. Construction of a new coal fired FBC steam plant generating steam and by-product electric power.

4. Construction of a new coal fired FBC steam plant generating steam and electric energy in co-generation, at about 50% of the facility's electric demand.

Capital Construction Costs

Capital design and construction costs were developed for the variations of the proposed plants, based on vendor quotations of major equipment and engineering estimates. Capital costs were extrapolated and adjusted for the five nominal firm capacities. Tabulations of these costs for the alternatives, including each plant size increment, based on firm steam and electric power generation capacity are given in Table 3.

Capital costs for maintaining the status quo (oil/gas firing) were considered as a 1979 fund which at 10% per year earning could serve to produce financing for replacement, renovation or addition of boiler and/or plant capacity.

Operating Costs

Recurring costs were individually calculated for each location. To accommodate the differential rates

TABLE 3

CONCEPTUAL CAPITAL COST ESTIMATE
COAL FIRED-FLUIDIZED BED COMBUSTION STEAM PLANT
COMPARISON OF COSTS

	PLANT CAPACITIES				
Plant Size	1	2	3	4	5
Steam Generation Only lbs/hr x 1000:	150	200	250	280	300
By-Product Power Generation kW:	5,000	6,000	6,500	7,000	7,000
Co-generation MW:	10	12	14	18	20

	PLANT COST (1979) (Dollars x 10^6)				
Plant Size	1	2	3	4	5
Steam Generation Only	25.6	29.2	32.7	33.9	35.5
By-Product Electric generation	29.8	33.9	37.5	39.5	41.2
Co-generation	34.7	39.2	43.6	46.0	48.0

	UNIT COST (1979) (Dollars/lbs/hr Plant Capacity)				
Plant Size	1	2	3	4	5
Steam Generation Only	171	146	131	121	118
By-Product Power generation	199	170	150	141	137
Co-generation	231	196	174	164	160
Power Plant $/kW (Co-gen.)	3,470	3,267	3,115	2,556	2,400
Notes: Locations	4 & 5	6	1	3	2

used, recurring costs were categorized as follows:

1. Annual fuel cost (oil, gas and coal).
2. Annual operation and maintenance costs.
3. Annual savings of purchased electricity.

Fuel Costs - The 1985 fuel requirements for each location were developed based on projected annual steam and power production. Prices used for oil and gas were those available from actual billings, escalated to expected 1985 levels. Values used for escalation were those of the figures published by the U.S. Government. Coal costs were calculated based on average prices indicated by potential future suppliers at current price levels, escalated to 1985 values based on U.S. Government published information.

Operating and Maintenance Costs - Annual operating and maintenance costs were derived by the addition of the following major expenses: operating labor, maintenance labor, sorbent material, plant electric energy consumption, ash removal and disposal and miscellaneous materials.

Purchased Electric Energy Savings - In the alternatives with electric generating capability, purchased electric power is replaced with less expensive power generated on site. The costs associated with self-generation are included in the fuel and O&M costs for each location. The savings on purchased power were calculated using current costs reported at each location. Plant turbine generator annual output is based on operation at average steam flow conditions, 7500 hours/year. Minimum condensing steam flow (as required for turbine cooling only) is assumed for 7500 hr/yr for co-generating plants.

COMPARISON OF COSTS

Life Cycle Cost Analysis

Life cycle cost analysis conducted for locations 1 through 6 compare the costs of maintaining the status quo of oil/gas firing to the costs of converting to coal use in a fluidized bed boiler plant and the production of by-product power, or co-generated electric power. The costs computed for 1979 were escalated to 1985 values as the year in which the operation will start. (The 25-year life cycle cost of each alternate, also the savings-investment ratio and discounted payback periods, were analyzed as shown on Tables 4 and 5.

Sensitivity Analysis

The life cycle costs (LCC) calculated are functions of several variables with future predictions. These predictions are subject to a degree of uncertainty; therefore, a sensitivity analysis was conducted for one selected site (Location 2). Sensitivity of LCC to changes in discount ratios and electric costs is shown in Figure 4.

CONCLUSIONS

General Conclusions

Based on analysis performed for the six different locations, the following summary of general conclusions is presented:

. Each location analyzed is being affected by increases in the cost and scarcity of oil and gas.

. The existing oil/gas fired boilers are not suitable for conversion to coal burning.

. New steam boilers would have to be installed at all sites before 1990 to replace aging existing units or to expand plant capacity to meet future loads.

. Requirements of the Fuel Use Act state that the new units will have to burn coal unless the user can obtain an exemption. Obtaining an exemption would prove difficult, based on the findings of the analysis.

. Fluidized bed combustion technology is commercially available in industrial steam generators. FBC provides the means to burn inexpensive, high sulfur coal in an environmentally acceptable manner.

. Disposal of waste materials produced should not present a major problem at the locations analyzed.

. Suitable coal and limestone supplies are available in sufficient quantities and at reasonable cost Coal and limestone deliveries can be made by truck or rail.

TABLE 4

25 YEAR LIFE CYCLE COST ANALYSIS OF ALTERNATIVES

FOR STEAM AND STEAM/ELECTRIC GENERATION

		STEAM GENERATION USING EXISTING & NEW GENERATORS (OIL/GAS)	STEAM GENERATION @ 250 psi COAL-FBC BOILER PLANT STEAM GENERATION ONLY	STEAM GENERATION @ 1350 psi COAL FBC STEAM/ELECTRIC BY-PRODUCT POWER	STEAM GENERATION @ 1350 psi COAL FBC STEAM/ELECTRIC CO-GENERATION
LOCATION 1	I. PRESENT COSTS (1979 DOLLARS)				
	1. Capital Costs	$ 3,800,000	$32,700,000	$37,500,000	$43,600,000
	2. Annual Fuel Costs	2,440,000($2.80/$10^6$Btu)	1,320,000($44/T)	1,540,000($44/T)	1,810,000($44/T)
	3. Annual Operating & Main.Costs	295,000	849,000	946,000	1,027,000
	4. Annual Electric Savings	0	0	(570,000)($26/MWH)	(820,000)($26/MWH)
	5. Total Annual Recurring Costs (2+3-4)	$ 2,735,000	$ 2,169,000	$ 1,916,000	$ 2,017,000
	II. 1985 COSTS (1985 DOLLARS)				
	6. Capital Costs	$ 5,434,000	$46,761,000	$53,625,000	$62,346,000
	7. Annual Fuel Costs	5,441,000	2,336,000	2,726,000	3,203,000
	8. Annual Operating & Main.Costs	410,000	1,180,000	1,315,000	1,427,000
	9. Annual Electric Savings	0	0	(1,008,000)	(1,451,000)
	10. Total Annual Recurring Costs (7+8-9)	$ 5,851,000	$ 3,516,000	$ 3,033,000	$ 3,179,000
	III. LIFE CYCLE COST (1985)	$65,472,000	$63,103,000	$62,855,000	$73,146,000
	IV. SAVINGS INVESTMENT RATIO(SIR)	BASE		1.69	
	V. DISCOUNTED PAYBACK PERIOD(DPP)	BASE		13.54 years(a)	
LOCATION 2	I. PRESENT COSTS(1979 DOLLARS)				
	1. Capital Costs	$ 4,500,000	$35,500,000	$41,200,000	$48,000,000
	2. Annual Fuel Costs	3,364,000($2.80/$10^6$Btu)	1,728,000($36/T)	1,944,000($36/T)	2,160,000($36/T)
	3. Annual Operating & Main.Costs	321,000	1,090,000	1,188,000	1,264,000
	4. Annual Electric Savings	0	0	(1,160,000($31/MWH)	(1,510,000)($31/MWH)
	5. Total Annual Recurring Costs (2+3-4)	$ 3,685,000	$ 2,818,000	$ 1,972,000	$ 1,914,000
	II. 1985 COSTS (1985 DOLLARS)				
	6. Capital Costs	$ 6,435,000	$50,765,000	$58,916,000	$68,640,000
	7. Annual Fuel Costs	7,502,000	3,059,000	3,441,000	3,823,000
	8. Annual Operating & Main.Costs	446,000	1,515,000	1,651,000	1,757,000
	9. Annual Electric Savings	0	0	(2,053,000)	(2,672,000)
	10. Total Annual Recurring Costs (7+8-9)	$ 7,948,000	$ 4,574,000	$ 3,039,000	$ 2,908,000
	III. LIFE CYCLE COST (1985)	$88,741,000	$79,345,000	$70,956,000	$77,706,000
	IV. SAVINGS INVESTMENT RATIO(SIR)	BASE		2.10	
	V. DISCOUNTED PAYBACK PERIOD(DPP)	BASE		10.71 years(a)	
				Δ SIR 2.03	
				DPP 10.25	
LOCATION 3	I. PRESENT COSTS (1979 DOLLARS)				
	1. Capital Costs	$ 4,200,000	$33,900,000	$39,500,000	$46,000,000
	2. Annual Fuel Costs	4,030,000($3.66/$10^6$Btu)	1,800,000($41/T)	2,080,000($41/T)	2,340,000($41/T)
	3. Annual Operating & Main.Costs	316,000	979,000	1,113,000	1,217,000
	4. Annual Electric Savings	0	0	(1,010,000)($32/T)	(1,340,000)($32/MWH)
	5. Total Annual Recurring Costs (2+3-4)	$ 4,346,000	$ 2,779,000	$ 2,183,000	$ 2,217,000
	II. 1985 COSTS (1985 DOLLARS)				
	6. Capital Costs	$ 6,006,000	$48,500,000	$56,500,000	$65,800,000
	7. Annual Fuel Costs	9,000,000	3,190,000	3,680,000	4,140,000
	8. Annual Operating & Main.Costs	439,000	1,360,000	1,550,000	1,860,000
	9. Annual Electric Savings	0	0	1,790,000	2,370,000
	10. Total Annual Recurring Costs (7+8-9)	$ 9,439,000	$ 4,550,000	$ 3,440,000	$ 3,630,000
	III. LIFE CYCLE COST (1985)	$104,688,000	$72,095,000	$66,332,000	$73,641,000
	IV. SAVINGS INVESTMENT RATIO(SIR)	BASE		2.07	
	V. DISCOUNTED PAYBACK PERIOD (DPP)	BASE		10.87 years (a)	
				Δ SIR 1.94	
				DPP 10.48	

NOTE: For notes see Table 5.

TABLE 5

25 YEAR LIFE CYCLE COST ANALYSIS OF ALTERNATIVES

FOR STEAM AND STEAM/ELECTRIC GENERATION

	STEAM GENERATION USING EXISTING & REPLACEMENT OIL FIRED BOILERS	STEAM GENERATION USING NEW FBC BOILER PLANT	STEAM GENERATION @ 1350 psig COAL FBC STEAM/ELECTRIC BY-PRODUCT POWER	STEAM GENERATION @ 1350 psig COAL FBC STEAM/ELECTRIC CO-GENERATION
LOCATION 4				
I. PRESENT COSTS (1979 DOLLARS)				
1. Capital Costs	$ 2,250,000	$25,600,000	$29,800,000	$34,700,000
2. Annual Fuel Costs	2,380,000($3.50/$10^6$Btu)	1,120,000($41/T)	1,330,000($41/T)	1,580,000($41/T)
3. Annual Operating & Main.Costs	287,000	793,000	890,000	977,000
4. Annual Electric Savings	0	0	(930,000)($40/MWH)	(1,320,000)($40/MWH)
5. Total Annual Recurring Costs (2+3-4)	$ 2,667,000	$ 1,913,000	$ 1,290,000	$1,237,000
II. 1985 COSTS (1985 DOLLARS)				
6. Capital Costs	$3,218,000	$36,608,000	$42,614,000	$49,621,000
7. Annual Fuel Costs	5,307,000	1,982,000	2,354,000	2,797,000
8. Annual Operating & Main.Costs	399,000	1,102,000	1,237,000	1,358,000
9. Annual Electric Savings	0	0	(1,646,000)	(2,336,000)
10. Total Annual Recurring Costs (7+8-9)	$5,706,000	$ 3,804,000	$1,945,000	$1,819,000
III. LIFE CYCLE COST (1985)	$62,977,000	$63,696,000	$58,466,000	$64,081,000
IV. SAVINGS INVESTMENT RATIO (SIR)	BASE		1.76	
V. DISCOUNTED PAYBACK PERIOD (DPP)	BASE		12.85 years(a)	

LOCATION 5				
I. PRESENT COSTS (1979 DOLLARS)				
1. Capital Costs	$2,250,000	$25,600,000	$29,800,000	$34,700,000
2. Annual Fuel Costs	2,450,000($3.50/$10^6$Btu)	1,120,000($40/T)	1,330,000($40/T)	1,610,000($40/T)
3. Annual Operating & Main.Costs	278,000	773,000	869,000	959,000
4. Annual Electric Savings	0	0	(792,000)($33/MWH)	(1,110,000($33/MWH)
5. Total Annual Recurring Costs (2+3-4)	$2,728,000	$ 1,893,000	$ 1,407,000	$ 1,459,000
II. 1985 COSTS (1985 DOLLARS)				
6. Capital Costs	$3,217,000	$36,608,000	$42,614,000	$49,621,000
7. Annual Fuel Costs	5,464,000	1,982,000	2,354,000	2,850,000
8. Annual Operating & Main.Costs	386,000	1,074,000	1,207,000	1,333,000
9. Annual Electric Savings	0	0	1,401,000	1,965,000
10. Total Annual Recurring Costs (7+8-9)	$5,850,000	$ 3,056,000	$ 2,160,000	$ 2,218,000
III. LIFE CYCLE COST (1985)	$63,612,000	$51,331,000	$46,440,000	$51,362,000
IV. SAVINGS INVESTMENT RATIO(SIR)	BASE		1.76	
V. DISCOUNTED PAYBACK PERIOD(DPP)	BASE		12.92 years(a)	

LOCATION 6				
I. PRESENT COSTS (1979 DOLLARS)				
1. Capital Costs	$3,000,000	$29,200,000	$33,900,000	$39,200,000
2. Annual Fuel Costs	2,670,000($3.50/$10^6$Btu)	1,120,000($41/T)	1,290,000($41/T)	1,580,000($41/T)
3. Annual Operating & Main.Costs	300,000	836,000	936,000	1,030,000
4. Annual Electric Savings	0	0	(800,000)($38/MWH)	(1,140,000)($38/MWH)
5. Total Annual Recurring Costs (2+3-4)	$2,970,000	$ 1,956,000	$ 1,426,000	$ 1,470,000
II. 1985 COSTS (1985 DOLLARS)				
6. Capital Costs	$4,290,000	$41,800,000	$48,500,000	$56,100,000
7. Annual Fuel Costs	5,950,000	1,980,000	2,280,000	2,800,000
8. Annual Operating & Main.Costs	410,000	1,160,000	1,300,000	1,430,000
9. Annual Electric Savings	0	0	(1,420,000)	(2,020,000)
10. Total Annual Recurring Costs (7+8-9)	$6,360,000	$ 3,140,000	$ 2,160,000	$ 2,210,000
III. LIFE CYCLE COST (1985)	69,858	56,078	51,060	56,339
IV. SAVINGS INVESTMENT RATIO (SIR)	BASE		1.74	
V. DISCOUNTED PAYBACK PERIOD	BASE		12.95 years(a)	

NOTE: (a) Computed based on comparison to "Base" scheme with $4.22/$10^6$ Btu 1979 fuel oil/gas costs.

Escalation rates (%) and escalation factor used:

	1980	1981	1982	1983	1984	1985	ESCALATION FACTOR	DIFFERENTIAL ESCALATION RATES
Capital Costs	6.5	6.0	6.0	———	———	———	1.43	0%
Annual O&M Costs	6.2	5.6	5.6	———	———	———	1.39	0%
Annual Fuel Costs								
Oil/Gas	16	14	14	———	———	———	2.23	8%
Coal	10	10	10	———	———	———	1.77	5%
Annual Electric Savings	10	10	10	———	———	———	1.77	7%

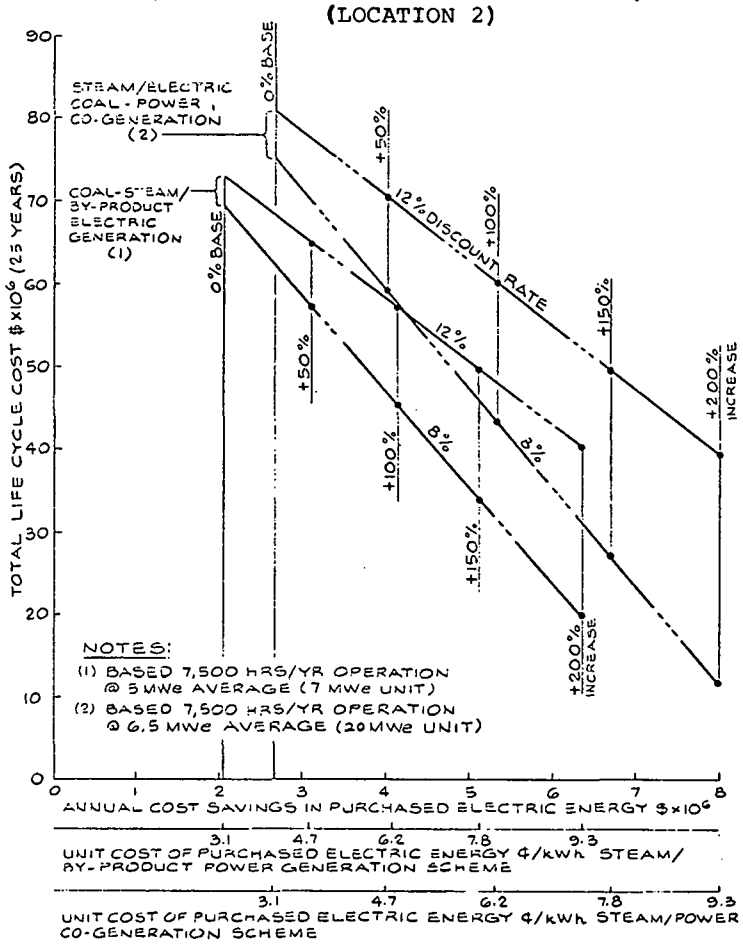


Figure 4

. Construction of a new coal burning FBC plant at each location would cost about ten times more than adding to or replacing existing oil/gas fired units. However, annual operating expenses for oil/gas fired plants are at least four times (or more) higher than coal fired plants. Using latest imported oil costs, discounted payback periods of eight years or shorter are attained.

. Installation of by-product power or co-generation capability in a new coal fired FBC plant produces significant savings in the cost of electric power consumed. Availability of "spinning" electric generators increases the reliability of electric power provided to a facility.

. Coal, limestone and ash can be handled and stored indoors with emissions of particulate matter and noise controlled with properly engineered systems.

. Coal firing can be phased-in in two stages using the existing plant for temporary standby.

. A "standardized" plant can be designed to reduce costs for converting multiple locations.

. The Federal Government currently offers a 10% tax credit (above the standard tax credit) for coal investments. FBC plant constructions qualify for this credit.

The following additional conclusions have been reached:

. Even at the very low cost of gas and electricity reported for several locations, the coal fired FBC steam generation and steam/by-product power generation alternatives are competitive with maintaining and expanding the existing oil/gas fired plants. For most of the locations, however, even when low cost mixed oil/gas fuels are used, the coal fired FBC steam generation with steam/by-product power generation alternatives have lower life cycle costs than maintaining present mode of oil/gas

operation (status quo).

. Increases in the price of oil and gas in the last year have greatly exceeded the conservative escalation factors used in the economic evaluation. The use of coal in FBC boilers, therefore, is more economical than the analysis actually shows.

. The by-product power alternative also allows the industrial facility to forego the purchase of certain quantities of high priced electric energy.

. Installation of either by-product power or co-generation facilities not only reduces operating costs at a specific location but also increases the reliability of the electric supply.

. On the basis of economic evaluation and the results of the life cycle cost analysis conducted, the writer has concluded that conversion of the existing facilities at each of the locations analyzed is both technically and economically feasible. Therefore, the industrial facilities analyzed were advised that implementation of FBC coal firing, in combination with by-product electric power generation, would be an overall benefit to the user, giving employment to addition six to eight people per location, would also eliminate dependence on uncertain and increasingly expensive oil and gas supplies, while reducing expenditures over the life of the plant.

Recognized Decision Making Barriers

For widespread industrial application of fluidized-bed combustion technology and by-product electric power generation, the following currently existing decision making barriers must be recognized, and by demonstrated satisfactory operation eliminated, reduced, or otherwise beneficially affected:

. Availability of FBC boilers from recognized vendors with standard commercial performance guarantees, including at least 98 percent carbon utilization and 90 percent sulfur capture.

. Total installed cost and operating costs to be comparable to, or lower than, conventional coal-fired units which are suitably fitted to meet environmental requirements.

. Demonstrated reliable long term operation of atmospheric FBC units in industrial facilities.

. At least a 4:1 practical and repeatable turndown ratio.

. At least 92% total system availability; that is 48 weeks on line per calendar year.

. Excess air level not to exceed 20 percent.

. $\pm$ 10^{o} steam temperature.

. Multiple fuel capability.

. Feedwater quality to be comparable to conventional units.

. Initial startup and shakedown not to exceed two weeks and subsequent startups are within 24 hours.

. Noise levels should not exceed that of a conventional unit, nor should OSHA requirements be exceeded.

. Total electric power requirements, that is power to make steam, should not exceed conventional units furnished with suitable flue gas cleaning devices.

. Waste product (ash) which is innocuous on commercial landfills.

. The minimum boiler efficiency, based on higher heating value of the fuel should not be less than 83%.

. Demonstrated long term environmental compliance.

. Availability of operators trained for FBC plant operation.

. Availability of fuels: coal, waste products,etc. for FBC use.

. Availability of sorbent material at a reasonable cost.

. Availability of disposal site or marketability of the ash and waste products.

. Availability of spare parts, replacement parts for future FBC maintenance. Fast developing technology within a short period of time could make certain boiler designs obsolete, making future purchase of replacement parts difficult and expensive.

Evaluations conducted for the six locations indicate that the technology is commercially available for industrial steam and power co-generation, using FBC technology, and that answers to some of the recognized decision making barriers are not yet available. However, within a relatively short period of time, by widespread use of the technology the industry could greatly reduce and/or eliminate all remaining decision making barriers.

Expected Payback Periods

The November/December 1979 estimated cost of FBC/by-product power generation plant construction the 1983/85 construction funding requirements,

estimated annual operating cost savings due to coal firing and the calculated discounted payback periods or the locations analyzed are the following:

Facility Location	Plant Cost (*) 1979 (Dollars x 10^6)	Plant Cost (*) 1985 (Dollars x 10^6)	Annual Operating (**) Cost Savings (Dollars x 10^6)	Payback Period (***) (Years) Oil Cost at $24/brl	Payback Period (***) (Years) Oil Cost at $40/brl
No. 1	37.5	53.6	5.6	13.5	8.0
No. 2	41.2	58.9	8.7	10.7	6.3
No. 3	39.5	56.5	7.4	10.9	6.4
No. 4	29.8	42.6	4.9	12.8	7.7
No. 5	29.8	42.6	4.8	12.9	7.8
No. 6	33.9	48.5	5.4	13.0	7.9

(*) Steam generation with by-product electric power.

(**) 1985 operation; coal vs. oil/gas. (Coal @ $36-44/T, oil/gas @ $4.22/$10^6$Btu $24/brl) 1979 cost.

(***) Comparison to oil/gas fired units continued operation with $4.22/$10^6$Btu (1979) fuel cost.

Based on the short payback periods and on the general findings of the evaluation, it was strongly recommended that by-product power co-generation with coal burning in FBC units should begin in major facility heating plants, as soon as possible. This technology appears to be the most economical environmentally acceptable technique for industrial steam plants. The sooner FBC/by-product power generation plants are in place, the lower implementation costs will be and the quicker operating savings will begin to accrue. See Table 6 and Figure 5.

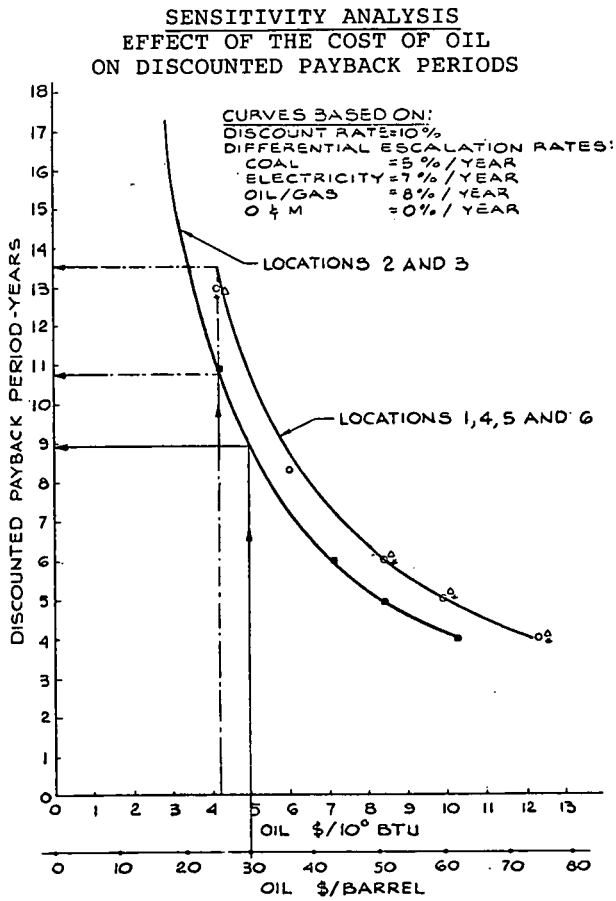


Figure 5

TABLE 6

SUMMARY
OF
ESTIMATED COST SAVINGS AND ADDITIONAL CAPITAL REQUIREMENTS
FLUIDIZED BED COAL VS. OIL/GAS FIRED PLANTS

FACILITY	COST OF FUELS OIL/GAS $/$10^6$Btu	COAL $/$10^6$Btu	ANNUAL FUEL COST SAVINGS $ x 1000 STEAM GENERATION ONLY 1979	ANNUAL FUEL COST SAVINGS $ x 1000 STEAM GENERATION ONLY 1985	ANNUAL FUEL COST SAVINGS $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1979	ANNUAL FUEL COST SAVINGS $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1985	ADDITIONAL LABOR REQUIREMENT (No.of Man)	TOTAL ANNUAL OPERATIONAL COST SAVINGS $ x 1000 STEAM GENERATION ONLY 1979	TOTAL ANNUAL OPERATIONAL COST SAVINGS $ x 1000 STEAM GENERATION ONLY 1985	TOTAL ANNUAL OPERATIONAL COST SAVINGS $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1979	TOTAL ANNUAL OPERATIONAL COST SAVINGS $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1985	ADDITIONAL CAPITAL REQUIRED $ x 1000 STEAM GENERATION ONLY 1979	ADDITIONAL CAPITAL REQUIRED $ x 1000 STEAM GENERATION ONLY 1985	ADDITIONAL CAPITAL REQUIRED $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1979	ADDITIONAL CAPITAL REQUIRED $ x 1000 STEAM & BY-PRODUCT POWER GENERATION 1985	CAPITAL RECOVERY TIME YEARS (xxx)
Site No. 1	2.80*	1.76	1,120	3,105	900	2,715	6-8	566	2,335	819	2,818	28,900	41,327	33,700	48,191	
	4.22**	1.76	2,357	5,864	2,137	5,474	6-8	1,803	5,094	2,056	5,577	28,900	41,327	33,700	48,191	13.54
	7.04***	1.76					6-8									8.00
Site No. 2	2.80*	1.20	1,636	4,443	1,420	4,061	6-8	867	3,374	1,713	4,909	31,000	44,330	36,700	52,481	
	4.22**	1.20	3,342	8,247	3,126	7,865	6-8	2,573	7,178	3,419	8,713	31,000	44,330	36,700	52,481	10.71
	7.04***	1.20					6-8									6.30
Site No. 3	3.66*	1.64	2,230	5,810	1,950	5,320	6-8	1,567	4,889	2,163	5,999	29,700	42,494	35,300	50,494	
	4.22**	1.64	2,846	7,187	2,567	6,697	6-8	2,183	6,266	2,780	7,376	29,700	42,494	35,300	50,494	10.87
	7.04***	1.64					6-8									6.40
Site No. 4	3.50*	1.64	1,260	3,325	1,050	2,953	6-8	754	1,902	1,377	3,761	23,350	33,390	27,550	39,396	
	4.22**	1.64	1,750	4,417	1,540	4,045	6-8	1,244	2,994	1,867	4,853	23,350	33,390	27,550	39,396	12.85
	7.04***	1.64					6-8									7.70
Site No. 5	3.50*	1.60	1,330	3,482	1,120	3,110	6-8	835	2,794	1,321	3,690	23,350	33,391	27,550	39,397	
	4.22**	1.60	1,834	4,606	1,624	4,234	6-8	1,339	3,918	1,825	4,814	23,350	33,391	27,550	39,397	12.92
	7.04***	1.60					6-8									7.80
Site No. 6	3.50*	1.64	1,550	3,970	1,380	3,670	6-8	1,014	3,220	1,544	4,200	26,200	37,510	30,900	44,210	
	4.22**	1.64	2,099	5,194	1,929	4,894	6-8	1,563	4,444	2,093	5,424	26,200	37,510	30,900	44,210	12.95
	7.04***	1.64					6-8									7.90

Notes * 1978 Fuel Prices ** $24/barrel October 1979 Price of Fuel *** $40/barrel 1980 February Spot Market Oil Price

(xxx) By-Product Electric Power Generation Scheme vs. Existing Oil/Gas Fired Systems Continued Future Operation

Analysis indicates that additional cost savings can be accrued, in addition to an increase in the reliability of power supplied to the facilities, by co-generating steam and electricity in the by-product power generation mode; therefore, when an industrial facility decides to convert to coal, installation of high pressure boilers and turbine generators to produce electric power should be encouraged.

FLUIDIC CATALYTIC-CRACKING

POWER-RECOVERY DYNAMIC COMPUTER SIMULATION

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Fluidic Cat Crackers (FCC) using the catalyst regeneration cycle are candidates for more power efficient operation by the use of high temperature dirty gas expanders. In a previous paper [1], a computer simulation was described for the steady state operation of the primary mechanical components, specifically the axial compressor and hot gas expander. The present work expands upon the steady state model to add the dynamic characteristics of these elements as well as the effects of the controlling process valves. In many applications the expander will develop more power than the axial compressor can absorb. A power absorbing source, specifically an electrical generator, converts the mechanical excess power into electrical energy. A review of the mechanical equipment and the electrical generator operating modes and controls is needed so that the process designer and operator will know how the system will respond if process upsets were to occur. The program code developed can simulate these elements for specific processes and demonstrate the logic control scheme proposed by the process designer. This information will therefore allow the process operator, process designer and mechanical equipment supplier an understanding of the interplay of the system control elements and define specific operating limits.

INTRODUCTION

Fluidic Cat Crackers (FCC) using the catalyst regeneration cycle are providing more power efficient operation by the use of high temperature dirty gas expanders. In a previous paper [1], a steady state computer simulation was described for the continuous operation of the primary mechanical components, specifically the axial compressor and hot gas expander. The need for a dynamic simulation became obvious as the mechanical equipment and controls became more sophisticated. The operating efficiency of the hot gas expander has increased since its first use in the early 1960's. The power developed in excess of the process air requirements can be significant in overall savings to the total process operation. The addition of an electrical generator will force the total mechanical string to be dependent not only on the process operation but the plant or outside electrical utility operation. The additi...

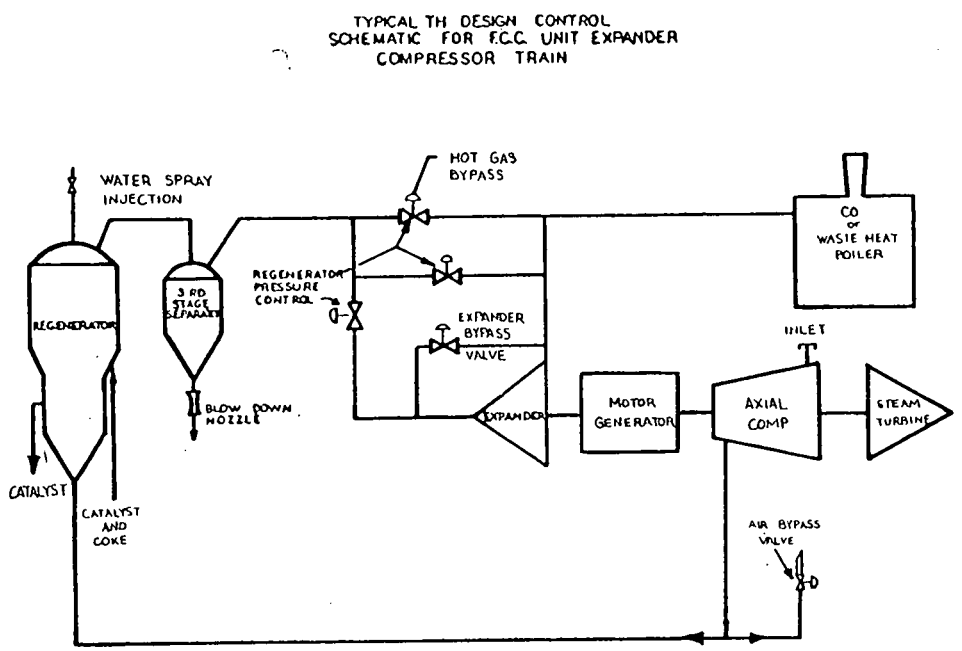


Figure 1. Typical FCC Regenerator System Schematic

of the electrical generator with its possible operating modes and controls needs to be simulated so that the process design/operator can know what to expect from the process if upsets were to occur. The mechanical equipment and the system controls interactions have to be known to protect the mechanical equipment and the process stationary vessels.

The present work expands the steady state model by adding the dynamic characteristics of the mechanical equipment, control valves, control logic, piping and pressure vessels. The program code can simulate the elements for a specific process and demonstrate the control logic scheme proposed by the process designer. It can give the process operators a chance to understand the process and the controls, prior to actually running the plant hardware. It will provide the process control designer with information of valve response time requirements to protect the process as well as the mechanical equipment. This program will therefore give the process operator, process designer and mechanical equipment supplier an understanding of the interplay of the system and control elements to simplify their understanding of the total process system operation.

The typical FCC regenerator system is shown in Figure 1. The basic components are the axial compressor, the regenerator, a third stage separator, various control valves, the expander and a Carbon Monoxide (CO) or waste heat boiler. In addition, a motor/generator and/or steam turbine can be added to the string. There are many possible combinations of equipment when an air compressor and an expander are combined with a steam turbine and a motor. The steam turbine is normally required only for starting purposes and is sized for 30% to 75% of normal air compressor operating power. The motor/generator is designed to absorb the excess power of the expander. It may also be used for starting if there is no

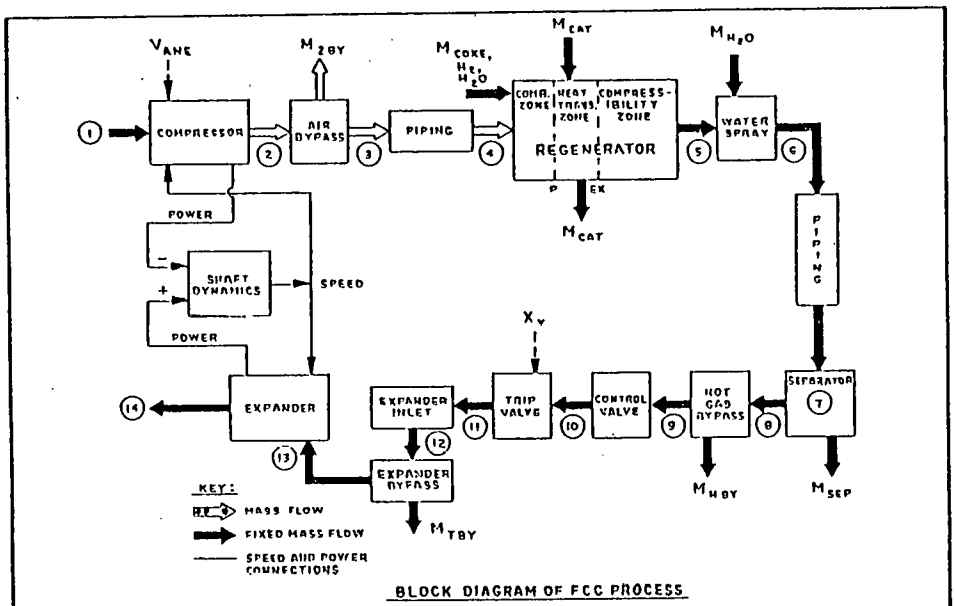


Figure 2. FCC Computer Program Elements

steam turbine specified or in combination with the steam turbine. Some trains may require gears when the motor speed cannot match the expander and axial compressor shaft speeds. Many cases can be proposed for different arrangements but usually process piping, plant layout, etc. will dictate the type of string required for a given site.

PROGRAM ELEMENTS

The program code developed for this dynamic simulation is a Fortran digital code on an IBM 370 system. The basic program elements considered by this code are shown in the block diagram (Figure 2) of the FCC process. Some of the elements are:

A. The air compressor, typically an axial unit, with adjustable vanes for flow variations. The train rotating speed is normally fixed if there is a motor or generator as part of the string.

B. The air control valves for blowoff, bypass and surge control.

C. The air discharge check valve between the compressor discharge and the regenerator inlet.

D. The power recovery expander (typically an axial inlet design).

E. Expander controls, specifically an inlet control/trip valve, hot gas bypass both before the inlet valve as well as an additional valve after the primary inlet.

F. The regenerator is modeled as a simple combustion chamber with compatibility of variable heat combustion capabilities.

G. The motor/generator is modeled as either a sink or source load depending on speed, expander power, and axial compressor power requirements.

H. Steam turbine can be added as a source load to provide start-up or make-up power to the axial compressor when the expander power is not sufficient.

I. System volumes are modeled so that

piping pressure drops as well as dynamic system responses may be expressed in the time dependent form.

COMPRESSOR CONTROLS

Figure 3 shows the basic control elements for the compressor. The compressor, be it an axial or centrifugal, would normally require some type of surge control to avoid the unstable aerodyanmic operating range. An emergency quick opening blow off valve can be used to load or unload the compressor as needed by process requirements. The blowoff valve can also be used during start-up to minimize the compressor load and reduce start-up power requirements. An axial compressor would normally be provided with variable vanes for flow control. The variable vanes can supply a constant discharge pressure and variable flow characteristics as required by the process while the train speed remains constant. The vane control is specified in the program with control logic. As an example the vanes may open, close, or fail position under a trip out the train.

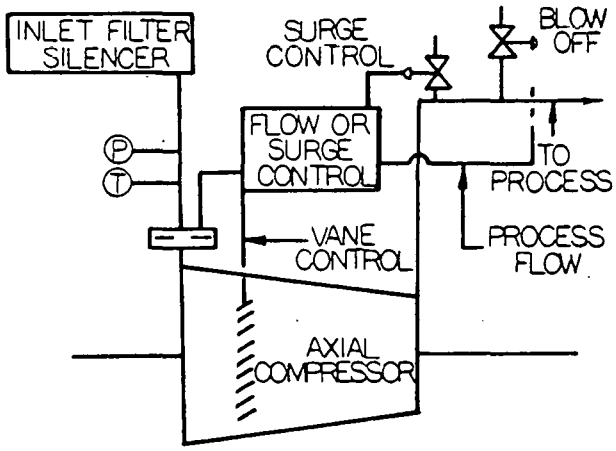


Figure 3. Axial Compressor Controls

REGENERATOR AND THIRD STAGE SEPARATOR

The model of the regenerator and third stage separator are as described in the previous paper [1]. The dynamics of the regenerator combustion system are included in this dynamic model so that temperature increases could be analyzed as a function of variable mass flow of the air supply. For modeling purposes, the catalyst and coke recirculation rate changes were assumed to be extremely slow and will not affect the system dynamics. The inlet piping volume has to be considered for the dynamic equations to allow for travel of flow, pressure and temperature disturbances in the system. The volume of the regenerator vessel has to be considered since it contains a very large part of the process stored energy. Considerations for the rate of pressure increases or decays have to be included. The third stage separator is also modeled as a volume element. The underflow or blow down is modeled as a constant percentage of the primary flow.

EXPANDER AND CONTROLS

Figure 4 shows the expander and some of the control valves contained in the simulator library. The expander normally has an inlet valve which may either be full open at all times or act to control the regenerator pressure. This valve may also have a trip function to react to an overspeed of the mechanical equipment train and shut it down. The primary hot gas bypass valves may be used as process pressure control or as process relief valves when the expander inlet valve goes closed. As many as two of these valves may be selected by the process designer if this mode of operation is specified.

The secondary hot gas bypass valve located between the expander inlet valve and the expander serves as a speed control and quick pressure relief under trip conditions [2]. Again it is up to the process designer to include or omit this control valve function.

In all cases the valve response to a change can be specified as well as a fast opening or closing rate for the tripping mode.

GENERATOR

The motor/generator element is modeled as a sink or source load. That is, the generator will absorb power up to a preset maximum limit or will provide power to the train again to the preset maximum limit. The motor/generator is normally an induction machine which will operate normally at 3600 RPM, or if geared - 1800 RPM, 1200 RPM etc. At full power in a generating mode the speed will normally exceed nominal speed by 1% or in motoring mode be below nominal speed by 1%.

STEAM TURBINE

The steam turbine when used in the train normally is the start-up device and will also provide make-up power when the expander cannot provide the full power required of the air compressor. The steam turbine is modeled within the program as a source power load. It will supply power and govern speed depending upon the control requirements of the process designer.

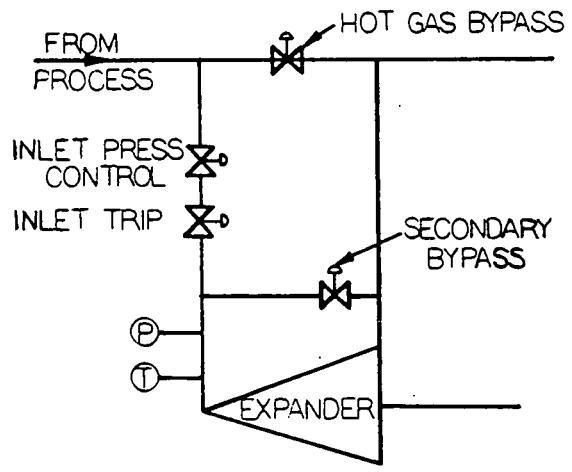


Figure 4. Hot Gas Expander Controls

As can be seen from the previous text, there are many controls and control variables to be considered in both the design and operation of the FCC string with power recovery. The Dynamic Simulation Program will allow the investigation of the control interactions that is; valve response times, speeds, control valve interactions etc., in trying to control pressure and/or flow. It can be used to investigate the effect on the process of a sudden load drop of the generator, predict the subsequent speed increase of the train, and evaluate how fast the expander trip valve has to close to provide overspeed protection for the string. Other process conditions that can be investigated are valve failure modes, either failing open, closed or improperly operating, process control logic, etc. Through the use of the program the process designer and process operator will have an indication of the process control and mechanical equipment response to transient upset condition.

SAMPLE PROBLEMS

A train has been modeled which consists of an expander axial compressor, motor/generator and steam turbine. The typical controls common to FCC systems were used (Figure 1). The problem presented typifies the program compatibility and is not intended to represent any specific process design or control logic.

The case of the generator load drop is the most common problem. The mechanical equipment designer needs to predict the train overspeed and verify the mechanical equipment integrity under this transient condition. Figure 5 demonstrates the effect the valve closure speed has on the overspeed conditions upon loss of normal operating electrical generation. As can be seen the quicker the valve closure the less

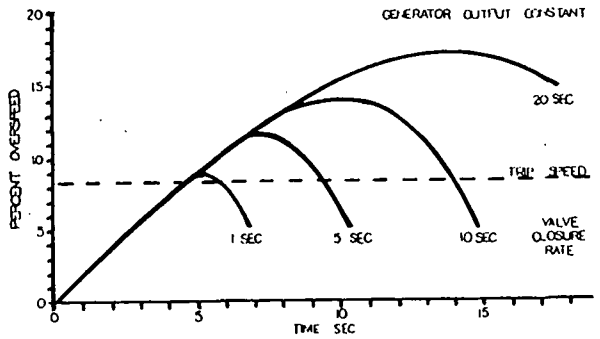


Figure 5. Train Overspeed as a function of expander inlet valve closure rate.

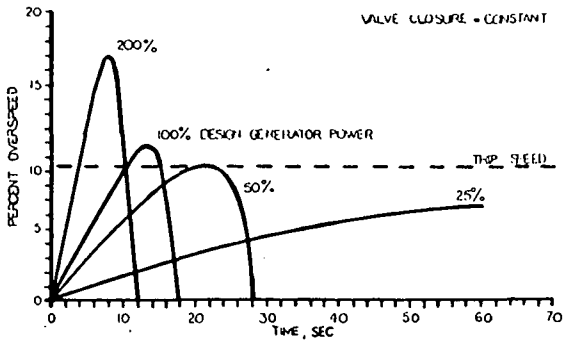


Figure 6. Percent overspeed as a function of excess generator power load drop for a constant valve closure time.

the overspeed. Most rotating equipment is designed to allow for transient speed increases of 20% above normal operation. A trip system and valve limiting this overspeed condition and preferably minimizing it should adequately protect the equipment.

Once a nominal valve speed has been specified the off design power generation effects on overspeed has to be reviewed. Figure 6 shows the maximum terminal speed of the modeled train for a constant valve closure rate. For the selected example problem the maximum capability of the generator was balanced by the valve closure speed such that the mechanical design limits were not exceeded. It is interesting to note that a loss of generator load below 25% of normal design generator power did not cause the string to reach trip speed and it continued to operate as the output of the expander was completely absorbed in the axial compressor.

The information generated above is only one example of the studies that can be done with the computer simulation. The system control logic can also be examined. Figure 7 is a plot of train speed versus time for a generator load drop. The load conditions resulted in a speed acceleration lasting 40 seconds before the high speed trip was activated. The curve shows there was no over speed as the load was just enough to reach the trip activation point. Figures 8, 9, 10 demonstrate the action of the control valves, resultant system pressures and mass flows respectively.

The valves used in the control analysis were the expander inlet and hot gas bypass. The axial compressor guide vanes were specified to "fail position" on trip. The compressor blow off valve was not included in the trip control logic. As can be seen in Figure 8 at time zero the trip valve is open to its normal control point and the hot gas bypass is also open bypassing flow and controlling the pressure. Between 0 seconds and 40 seconds the expander inlet valve remains in its normal position. The hot gas bypass is controlling the regenerator pressure. A response was specified which resulted in the valve position constantly adjusting to the changing flow and pressure conditions. Once the expander overspeed trip system was activated (40 seconds into the transient) the expander inlet valve closed in 2 seconds and the hot gas bypass valve opened at a slower specified rate.

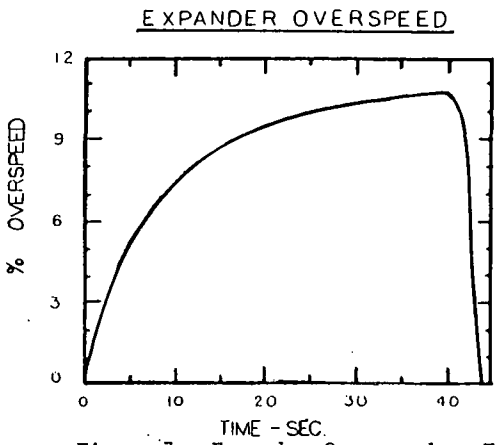


Figure 7. Expander Overspeed vs Time

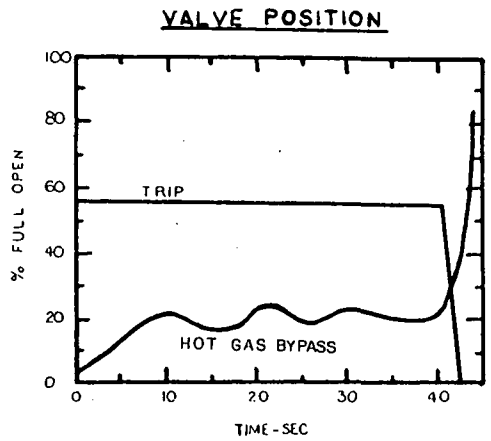


Figure 8. Valve Position vs Time

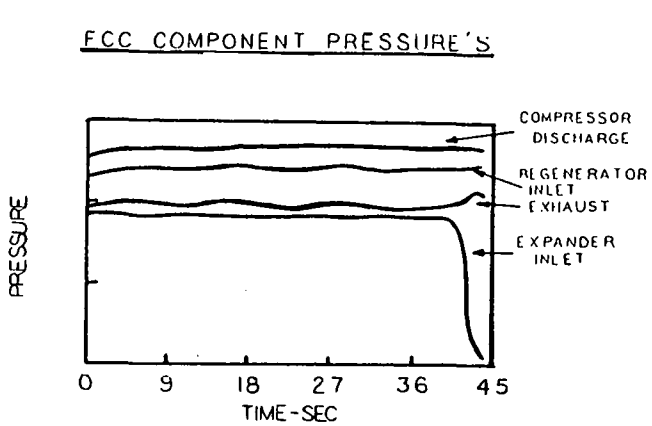


Figure 9. System Pressure vs Time

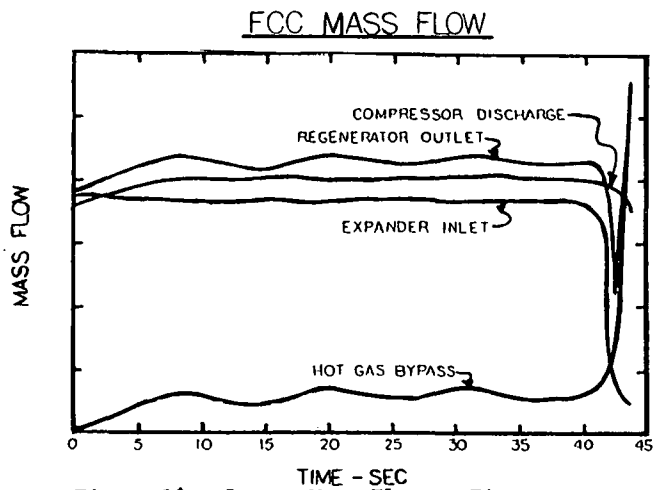


Figure 10. System Mass Flow vs Time

The system pressure response to the transient condition is shown in Figure 9. The compressor discharge pressure is the highest pressure level of the system. The regenerator and expander pressures are lower respectively due to the piping system pressure drops. Upon tripping of the inlet valve the expander pressure rapidly decreases. The compressor pressure responds more slowly to the decay since the speed is not dropping rapidly and the regenerator volume pressure is slow to decay.

Figure 10 demonstrates the response of the system mass flow to the transient condition. At time 0 seconds the compressor output flow is lower than the expander or regenerator flow. The regenerator flow is greater than the compressor due to the addition of the mass of combustion fuel. The expander flow is less than the regenerator outlet since the third stage separator has some blow down and the hot gas bypass valve is controlling the system pressure. Upon trip the flow to the expander drops to almost zero. The compressor flow also starts to fall off as the power and speed decrease. The regenerator outlet flow will drop off as the expander valve closes and the hot gas bypass valves

starts to open. Once the hot gas bypass valve goes goes to full open the instantaneous rate of flow increases due to the upset conditions.

CONCLUSION

A computer code has been developed for a dynamic simulation of the FCC regenerator process. This program will allow the process designer, plant process operator, and mechanical equipment designer to predict the design and off design operation of the process. The proposed control system and individual components can be evaluated to provide a highly reliable system. The plant process operators will be given an insight into the system operation giving them a greater understanding of the controls and their interactions, and providing them with better training to respond to an upset or malfunction thereby maintaining extended operating time.

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THE ORGANIC RANKINE CYCLE SYSTEM: ITS APPLICATION TO EXTRACT ENERGY FROM LOW-TEMPERATURE WASTE HEAT

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ABSTRACT

The conservation of energy by its recovery from low temperature waste heat is of increasing importance in today's world energy crisis. The Organic Rankine Cycle is a cost efficient and proven method of converting low temperature (200-400°F) waste heat to mechanical and/or electrical energy. Applying the Organic Rankine Cycle technology to typical liquid and mixed component condensing streams is described using actual examples. Selection of the organic working fluid is explored.

The Rankine Cycle efficiency is directly dependent upon the temperature difference between its evaporating and condensing phases. The evaporating level is set by the heat source; therefore, to maximize efficiency, it is essential to obtain the lowest condensing temperature practical. Various condensing schemes are discussed emphasizing methods of optimizing the net output of the total system.

Several Organic Rankine Cycle commercial applications are summarized with experience and general performance given.

The economics and optimization techniques in typical applications including multiple heat sources are discussed.

INTRODUCTION

The Organic Rankine Cycle, using an organic fluid as its working medium, is an advanced form of the classical Rankine Cycle, developed to enhance its use in recovering energy from low temperature waste heat. Its technology is founded upon the Steam Rankine Cycle System which is currently the major source of electrical and mechanical power generation in our industrial world. As early as 1960, efforts [1] were begun to prove the commercial applicability of using organic working fluids in a Rankine Cycle to extract energy from low temperature waste heat. By 1968, a 3.8 megawatt unit using R-11 refrigerant was placed in commercial operation in Japan [2] and currently has more than 80,000 hours of operational experience. To understand the problems of applying this technology to typical low temperature applications, this paper reviews the basic considerations and notes the solutions used in several applications.

BASIC ORGANIC RANKINE CYCLE

The basic Organic Rankine Cycle may be described using the Pressure-Enthalpy Diagram of a typical working fluid (R-11). (See Figure 1). Shown is the theoretical subcritical Rankine Cycle without superheat. From point ① to ② the saturated liquid working fluid is pressurized by feed pumps. From ② to ③ heat is added at constant pressure first raising the liquid temperature to the boiling point and then evaporating it to a saturated vapor. From ③ to ④ the pressurized vapor is expanded adiabatically in a turbine developing mechanical energy. From ④ to ① the vapor is condensed at constant pressure to a saturated liquid completing the cycle.

RANKINE CYCLE EFFICIENCY

The theoretical Rankine Cycle efficiency (η_R) is defined as:

$$\eta_R = \frac{h_3 - h_4}{h_3 - h_1}$$

Since each fluid has its own widely differing and unique pressure enthalpy characteristics, it follows that the theoretical Rankine Cycle efficiency for each fluid will also be different for any given temperature interval. Figure 2 compares the theoretical Rankine efficiency for several hydrocarbons, fluorocarbons and water within the evaporating temperature range of interest (160 to 320°F). A common condensing temperature of 104°F was used for comparison.

FIGURE - 1

Pressure-Enthalpy Diagram for Refrigerant 11

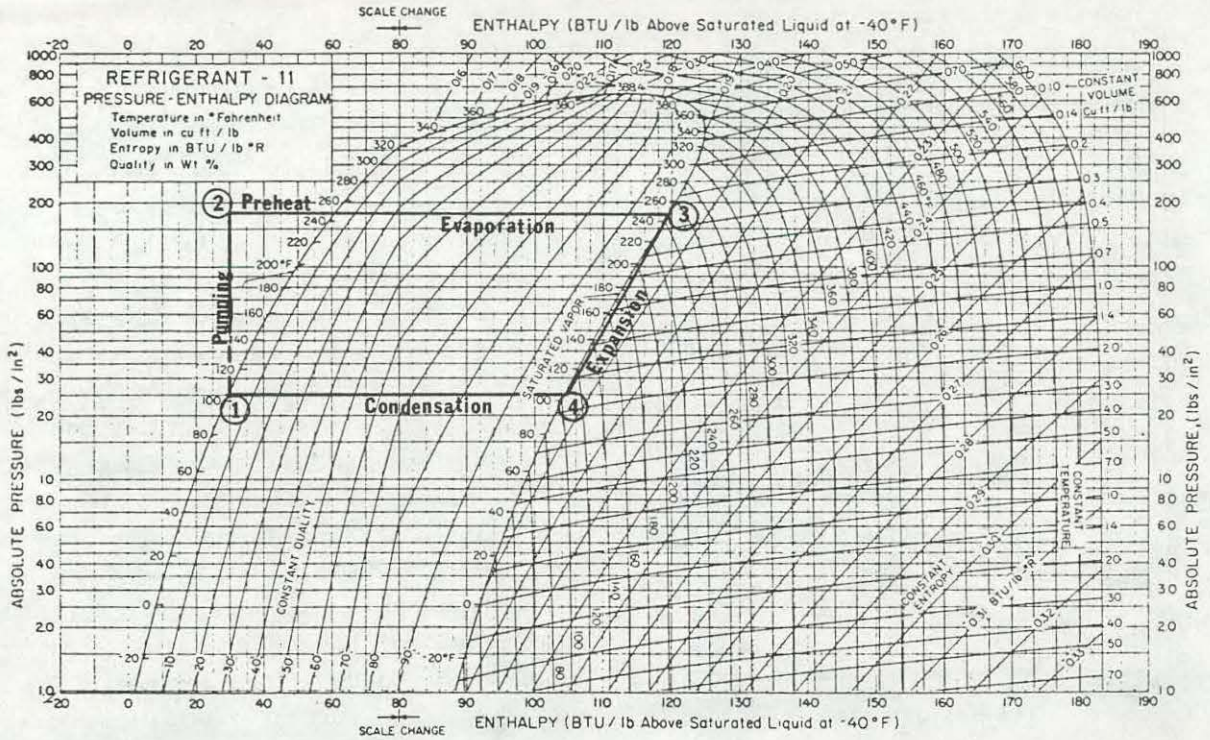
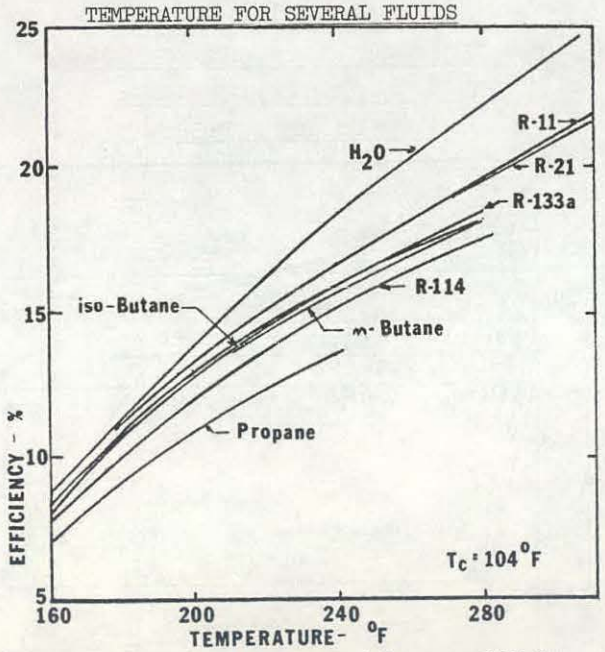


FIGURE - 2

THEORETICAL RANKINE CYCLE EFFICIENCY VS. EVAPORATING TEMPERATURE FOR SEVERAL FLUIDS



In an actual cycle, energy must be expended in pressurizing the working fluid (points ① to ②, Figure 1). This energy (W_p) may be expressed as a percentage of theoretical cycle output (W_o) as follows:

$$\frac{W_p}{W_o} = \frac{K_1 \Delta P}{\rho (h_3 - h_1) \eta_R \eta_P}$$

Figure 3 provides a comparison of the pumping power ratios for the same working fluids shown in Figure 2. It has been shown by Doerner [3] that an ideal working fluid is obtained when the saturated vapor line is parallel to the lines of constant entropy. This provides maximum efficiency while operating the turbine in the dry vapor region. He has shown that a fluid with a vapor heat capacity $(C_p)_g$ of 21 (Btu/Lb-mole °F) at its normal boiling point will meet this criteria and can be used as a guide for selecting the working fluid.

Table I lists the $(C_p)_g$ for some fluids of interest.

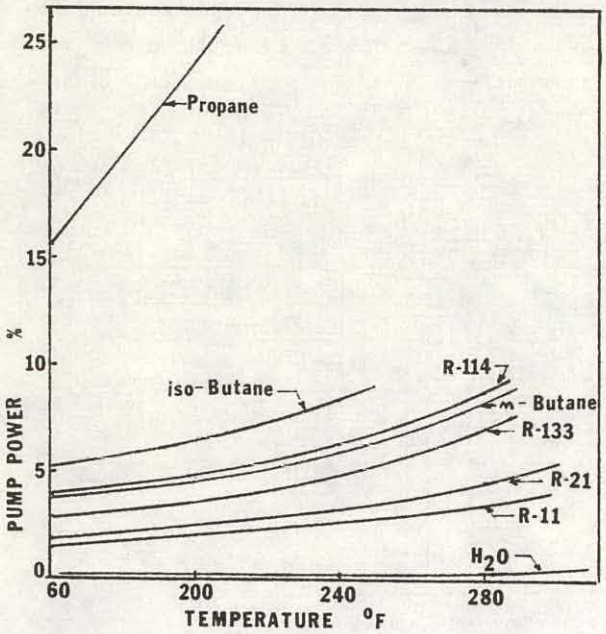
TABLE I

VAPOR HEAT CAPACITY (BTU/LB. MOLE °F) OF VARIOUS FLUIDS AT THEIR NORMAL BOILING POINT

FLUID	$(C_p)_g$	FLUID	$(C_p)_g$
R-11	19.72	C_3H_8	15.34
R-21	15.64	C_4H_{10} (n)	22.96
R-114	28.5	C_4H_{10} (iso)	20.87
R-133a	19.83	H_2O	8.75

FIGURE - 3

PUMPING POWER AS A PERCENT OF THEORETICAL OUTPUT VERSUS EVAPORATING TEMPERATURE FOR SEVERAL FLUIDS (CONDENSING TEMPERATURE = 104°F)



It can be seen from Table I that fluids such as R-21, propane and water having $(C_p)_g$ values significantly less than 21 cause operation of the turbine in the wet vapor region and may cause turbine erosion unless special steps are taken. While vapor superheating may be used to eliminate erosion, it normally is unattractive with low temperature heat sources.

SELECTING A WORKING FLUID

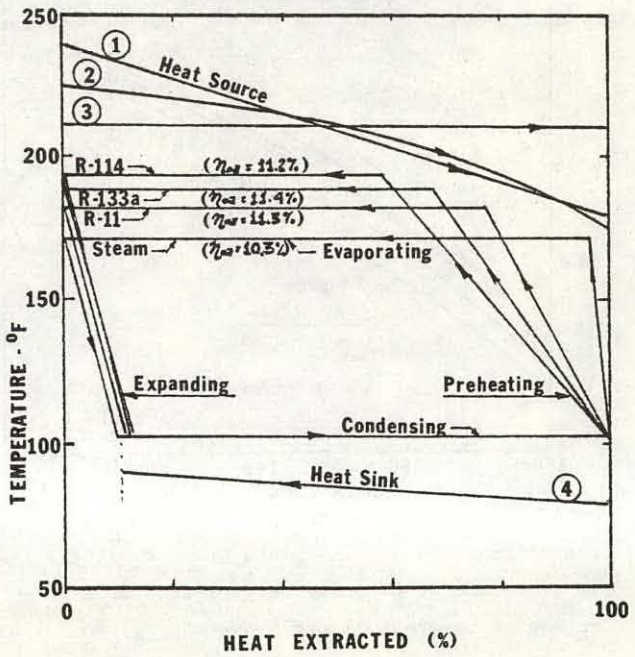
Using data similar to that presented in Figure 2 and 3, one could select the most efficient working fluid for any desired temperature range. As shown, water would be the first choice and certainly provides one major reason for its universal use especially in the higher temperature range. However, in the low temperature (200-400°F) waste heat application, there are other important factors which often override efficiency considerations alone. A few of these factors are:

1. The nature of the heat source and whether the waste heat is stored in the latent or sensible form.
2. The heat ratio between liquid-heating and vaporizing the working fluid during heat exchange with the energy source.
3. The specific volume of the working fluid vapor in the power generating process.
4. The nature of the working fluid's adiabatic expansion, that is, does it expand into the wet or dry zone?
5. The metallurgical, environmental and safety characteristics of the working fluids.

Let us first examine the nature of the heat source as it may be combined with the nature of the working fluid (Figure 2 & 3). Heat is available in two forms, sensible or latent. Figure 4, Curve ① shows a typical sensible heat source which could be any liquid or non condensible gas. Examples could be water, flue gas, liquid hydrocarbon, acids, etc. To extract the most energy from this type of heat source using a Rankine Cycle, one must determine which working fluid can provide the best overall efficiency. In Figure 4, the temperature-heat duty cycles for four working fluids are shown, each using a pinch point temperature of 10°F. The slopes of the preheating lines are determined by the ratio of sensible to latent heat for the working fluids and may be obtained from the specific pressure enthalpy diagrams. Using the efficiencies found in Figure 2 and 3, the overall theoretical efficiencies including pumping loss is given on each cycle. For this example, it is noted that the three refrigerants are

FIGURE - 4

TEMPERATURE - HEAT DUTY CHARACTERISTICS FOR SEVERAL FLUIDS WITH VARIOUS TYPES OF HEAT SOURCES



very similar in efficiency while the steam cycle is lower by 10%.

The heat source containing both sensible and latent heat is shown by the typical Curve ② in Figure 4. This heat source must be treated in the same manner as the sensible source; however, because of the curved shape, determined by the ratio of the contained sensible to latent heat, the resultant choice of working fluid may change. Waste heat sources of this nature are commonly found in the petroleum, petrochemical and chemical industries.

Such sources may be mixtures of steam and non-condensible gases (CO, CO_2, H_2, N_2, O_2) or mixture of various hydrocarbon vapors which may also contain steam.

The latent heat source shown as Curve ③ on Figure 4, provides the simplest case to study. Here the location of the pinch point does not affect the evaporation temperature and the most efficient working fluid may be used. Typical latent waste heat sources are low pressure steam and single hydrocarbon compounds.

In some applications, the terminal temperature of the heat source may be varied to best suit the energy recovery system. In these instances, working fluids with pinch points farthest to the left (shallowest preheating slope) can extract the largest quantity of heat and usually prove most economically attractive.

It should also be noted that when the inlet temperature of a sensible heat source is increased, the outlet temperature can be lowered, effectively pivoting the curve about the Rankine Cycle pinch point. This allows extracting more waste heat from a given stream than would be expected by the increase in inlet temperature alone. As noted above, the working fluid which provides a shallow preheating slope is most beneficial.

Heat Load Handling Capacity

Efficiency is but one facet in the selection of a working fluid; now let us examine the effects of specific volume and heat capacity. In any practical system, the cost of equipment is normally proportional to its size. Therefore, the size of the expander and the working fluid transport lines must be considered. The expander size is determined by the combination of many factors such as type of machine, radial or axial, impulse or reaction, the specific speed selected, etc.; however, the basic flow areas are governed by the character of the working fluid used. To compare working fluids for their ability to carry heat per unit of flow area, it is possible to establish a figure of merit based upon specific volume, heat capacity, and sonic velocity for the operating temperature levels of interest. Table 2 lists the relative figures of merit on both inlet and outlet conditions for various fluids of interest. An evaporating temperature of 200°F and condensing temperature of 104°F were used for this table.

TABLE 2

HEAT CAPACITY FIGURES OF MERIT FOR VARIOUS FLUIDS AT 200°F EVAPORATION AND 104°F CONDENSING TEMPERATURES

FLUID	FIGURE OF MERIT (MM BTU / HR. FT^2)	
	INLET	OUTLET
R-11	307	72
R-21	621	148
R-114	513	123
R-133a	613	138
C_3H_8	2237	438
$C_4H_{10}(n)$	714	177
C_4H_{10}(iso)	909	231
H_2O	153	14.7

While the values given in Table 2 can not be used for equipment design purposes, they do allow a valid comparison of sizes; larger values predict smaller expanders and transport line sizes and costs. As noted in this table, the selection of a working fluid can change equipment flow areas by one order of magnitude, thus, making this a serious parameter to consider in any design. It should be noted that the Figures of merit change rapidly with the temperatures selected and any valid study must be conducted with the specific temperature of interest.

Environmental, Commercial And Safety Conditions

In addition to the factors affecting basic performance, it is often necessary to consider other characteristics in the selection of the working fluid. Take for instance the following:

1. Flammability - Will the fluid burn or support combustion? Will spills or leaks create a fire hazard?
2. Stability - Does the fluid remain stable (does not decompose) within the temperature extremes of interest? Is the fluid compatible and remain stable

when mixed with other fluids in the system with which it may come in contact because of leakage or equipment failures?

3. Toxicity - Is the fluid toxic or hazardous to operators?

4. Contamination - Is contamination of the heat source or cooling source by the working fluid acceptable, and vice versa?

5. Environmental - Will normal operation and maintenance procedures cause violations or environmental regulations, (air, water or land)?

6. Cost - What is the initial expense of charging a system and keeping it charged in operation?

7. Availability - Is the fluid commercially available or would its use constitute the total world's output?

8. Compatibility - Is the fluid corrosive to normal construction materials? Since each of the categories mentioned above is the subject for numerous books and papers, they will not be further explored here. Mention is made as a reminder that these characteristics should not be ignored.

This paper has discussed principally the subcritical Rankine Cycle without superheat. While critical and supercritical cycles or cycles with superheat may be used, it is often found that any advantages obtained are offset by the added complexity of equipment and/or system control. In any industrial process where energy is to be recovered from waste heat, it is of paramount importance that the recovery system does not reduce stream reliability or distract operators from producing the product.

CONDENSING SYSTEMS

The previous discussions have dealt with the maximization of the evaporation temperature to obtain a high cycle efficiency. Since efficiency is nearly proportional to the cycle temperature difference, the same result can be achieved by lowering the condensing temperature. Greater benefits are actually obtained per degree of temperature change at the condensing end due to the nature of the pumping losses (Refer to Figure 3). The condensing temperature is determined by the heat sink or cooling source. Our choice of a cooling source is normally limited to large bodies or water (lake, river, ocean) or the air. Environmental regulations have reduced the desirability of using once through water systems in many instances so we are often left with our surrounding air as the only viable heat sink.

Three type of condensers are commercially available to condense the working fluids. First, the shell and tube condenser using cooling water from either a once through supply or from a cooling tower source. Second, a wet surface air condenser (often called evaporative condenser), a third, a "fin-fan", or dry, air condenser.

Water Cooling

Curve (4) of Figure 4 shows a typical heat sink curve for the Rankine Cycle. It is desirable that the heat sink have as small a temperature rise as possible providing a low condensing temperature, thus increasing the output of the Rankine Cycle. The shell and tube condenser can operate as shown in Figure 4; however, large quantities of cooling water must be used if a small temperature rise is to be achieved. In most applications it is necessary to balance the increased cost of cooling water pumping against the value of the increased energy recovered. In general, it has been found that for once through systems, a cooling water temperature rise of 10-15°F is economical while in cooling tower applications a 20-30°F temperature rise provides the better return.

Wet Surface Cooling

When cooling water is at a premium, the wet surface air condenser provides an alternate choice. It cools by the evaporation of water in air using only 1 to 5% of the water needed by the once through shell and tube condenser. Also, the waste heat is rejected to the air as in the water cooling tower or fin fan systems, making it more environmentally acceptable. Since cooling is mainly by water evaporation, the temperature change of the cooling curve is relatively small, thus matching closely the condensing curve of the Rankine Cycle. In the wet surface air condensing system, the Rankine Cycle working fluid is condensed inside banks of tubes placed in the stream of cooling air mixed with copious quantities of recirculated water. In this arrangement, lower condensing temperatures can be achieved for a given environmental condition because only one temperature difference is required between evaporating water and working fluid condensate versus two for the cooling tower system. The wet surface air condenser operating power requirements are generally less, while its capital costs are normally greater than the comparable shell and tube condensing arrangement. The wet surface air condenser can be operated with the air and water in either a countercurrent or

co-current configuration. For use with the Rankine Cycle, the co-current configuration offers the advantages of a flatter cooling curve, more uniform wetting of the tube surfaces and less carryover of water droplets.

Dry Air Cooling

In conditions where water is unavailable or when yearly average air temperatures are very low, the use of the "fin-fan" air condenser may be used as the Rankine Cycle heat sink. Since the fin-fan arrangement condenses the working fluid inside banks of tubes placed in an air stream, condensing heat is carried off only by the sensible heat in the air stream. This requires that the air temperature rise be large or the air flow be large; both are undesirable characteristics. The large temperature rise increases the Rankine Cycle condensing temperature, reducing power extracted while large quantities of air flow would require large auxiliary power losses. Only under extreme conditions could this type of condensing be used economically in energy extraction from low temperature waste heat.

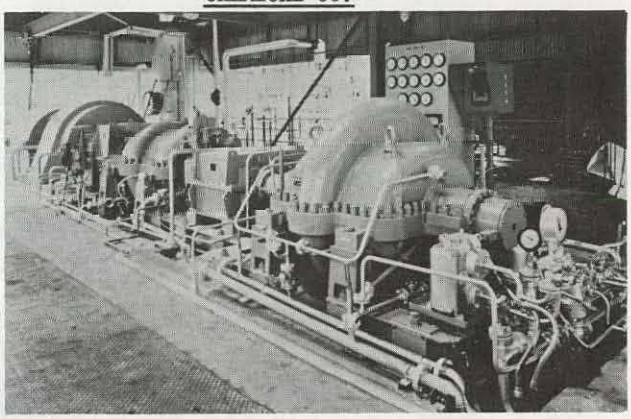
COMMERCIAL APPLICATIONS

Two commercial installations are here examined. They represent two widely different applications from the nature of the heat source, system size, cooling systems and working fluids used.

First, an installation at the Mitsubishi Gas Chemical Company in Mizushima, Japan, is extracting energy from the waste heat of a mixed xylene distillation process. This heat source contains both latent and sensible heat, and may be characterized by Curve ②, of Figure 4, with its temperature higher than those shown on Curve ②. It contains multiple heat sources using the overhead condensing streams of both the Orthoxylene and Ethylbenzene distillation columns to vaporize the R-11 refrigerant to power a single stage radial inflow expander. The 3800 KW of energy extracted by the expander is used to power a large propane refrigeration compressor and a 2000 KW synchronous Generator-motor. Figure 5 shows the machinery room of this installation. A countercurrent evaporative condenser is used as the combined heat sink for the Rankine Cycle and propane refrigeration system. This Organic Rankine Cycle has more than 80,000 hours of operation since its installation in 1968 and has demonstrated a typical availability of more than 98%.

FIGURE - 5

MACHINERY ROOM - ORGANIC RANKINE CYCLE INSTALLATION - MITSUBISHI GAS CHEMICAL CO.



The second installation is at a concentrated sulfuric acid plant in the U.S. Extracting only sensible heat from the acid, this heat source is described by Curve ① of Figure 4. The waste heat generated by the sulfuric acid manufacturing process is used to vaporize the R-133a selected as the working fluid for this unit. A single stage radial inflow expander drives an induction generator developing 560 KW of electrical power under yearly average conditions. Once through river water is used to condense the working fluid in a shell and tube condenser.

Table 3 is provided as a summary of the characteristics and general performance for these two installations.

OPTIMIZATION AND ECONOMICS

The determination of the optimum energy recovery system from low temperature waste heat cannot lose sight of the economic trade-off. In addition to selecting an efficient and economic working fluid, consideration must be given to the heat exchanger design and the temperature differences to be used. The system equipment cost increase for each incremental decrease in temperature difference must be balanced against the increased energy recovery created by that change. This care in analysis must be applied to both the evaporation and condensing phases of the cycle.

Economy of size must be used wherever possible. As is true of many industrial processes, there is a correct size for the best economical case. In some applications it requires using less than the total source available, while in others it may be necessary to combine two or more heat sources to reach a

TABLE 3

CHARACTERISTICS AND PERFORMANCE FOR TWO ORGANIC RANKINE CYCLE INSTALLATIONS

Heat Source	Installation 1 Mixed Xylene Vapors	Installation 2 Conc. Sulfuric Acid
Fluid flow rates (#/hr)	683,000	927,700
Temperature in (^{o}F)	289 - 307	240
Temperature out (^{o}F)	156 - 230	183
Heat duty MM Btu/hr	105	19.4
Working fluid	R-11	R-133a
System output	3800 KW (generator + propane compressor)	560 KW (generator)
Expander type	Double flow single stage radial inflow	Single flow single stage radial inflow
Expander speed	5280 RPM	9000 RPM
Expander nozzle type	fixed	variable
Vaporizer - type	U-tube kettle	Fixed tube sheet shell & tube
Vaporizer - temp. (^{o}F)	253^{o}F	190^{o}F
Preheater - type	Shell & U-tube	Shell & tube
Condenser - type	Evaporative Condenser	Fixed tube sheet shell & tube
Cooling water temp. (^{o}F) in/out	-	63/73
Condensing temp. (^{o}F)	104	85
Generator rating	2000 KW synchronous 3300 V, 60 HZ. 3 ϕ 1800 RPM	650 KW induction 2400 V, 60 HZ. ϕ 3628 RPM
Auxiliary pumping power	294 KW	55 KW
Overall system efficiency (%)	12.3	9.8

practical case. When combining sources, it is important that they be compatible in regard to operating time, load and utilization. The selection of the best plant design condition for designing the Rankine Cycle System is useless if that condition is never realized in operation or its availability is low.

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NOMENCLATURE

h_1 = enthalpy of the saturated liquid (Btu/Lb)

h_3 = enthalpy of the saturated vapor (Btu/Lb)

h_4 = enthalpy of the adiabatically expanded vapor (Btu/Lb)

K_1 = dimensional constant = .1852 $(\frac{Btu}{ft^3} \quad \frac{In^2}{Lb})$

ΔP = differential pressure (psi); pump press. rise

W_p = pump power

W_o = cycle output power

η_R = theoretical Rankine Cycle efficiency (%)

η_{oa} = overall cycle efficiency (%)

η_P = pump and driver combined efficiency (%)

ρ = working fluid density (Lb/ft^3)

POWER GENERATION FROM WASTE HEAT USING ORGANIC RANKINE CYCLE SYSTEMS

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ABSTRACT

Many efforts are currently being pursued to develop and implement new energy technologies aimed at meeting our national energy goals. The use of organic Rankine cycle engines to generate power from waste heat provides a near term means to greatly increase the fuel utilization efficiency of many processes. Sundstrand has developed a 600 KW ORC unit to recover energy from various waste heat sources. A field test program has been jointly funded by Sundstrand and the U. S. Department of Energy. As part of this program, five units are being placed in field to demonstrate the economic viability and the reliability of the equipment in commercial and industrial applications. This paper describes the system and the field test program.

INTRODUCTION

The Sundstrand Organic Rankine Cycle (ORC) Waste Heat Power Conversion System is intended to be a universal bottoming cycle that can convert the energy in waste heat streams into usable shaft power. The nominal rating of the unit is 600 KWe or 900 SHP. The basic bottoming cycle concept is shown in Figure 1.

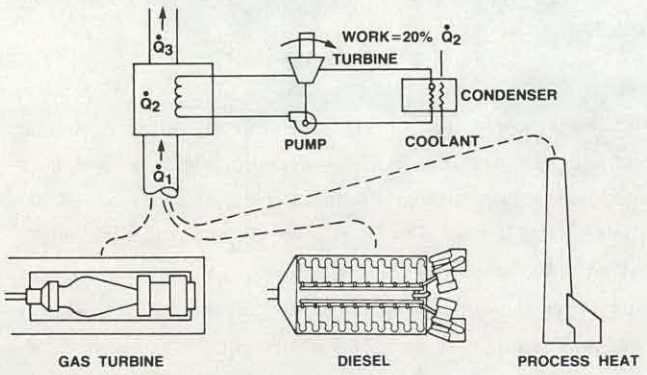


Figure 1. Bottoming Cycle Concept

By changing the configuration of the waste heat recovery vaporizer, the unit can accommodate any gaseous waste heat stream that has a temperature above 600°F and sufficient flow. The vaporizer can also be designed for liquid or condensing waste heat streams with temperatures above 500°F, which makes it well suited for solar power systems using concentrating collectors.

SYSTEM OPERATION

The system operates on Rankine cycle which is shown in schematic form in Figure 2. The diverter valve directs the waste heat stream through the vaporizer. The working fluid is boiled and slightly superheated in the vaporizer. The superheated vapor expands through the turbine, generating mechanical power. This expansion process causes the working fluid to become highly superheated. The vapor is desuperheated by passing it through a

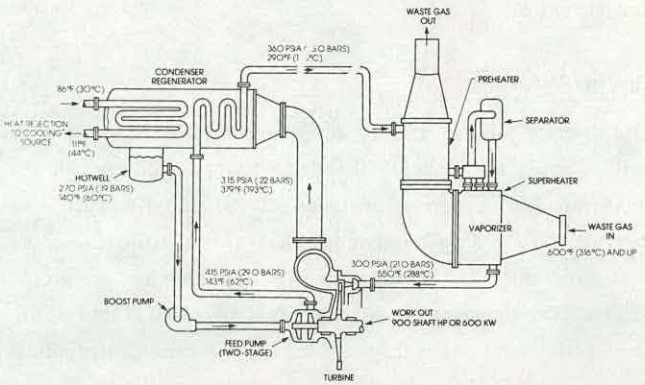


Figure 2. 600 kW ORC Schematic

regenerator, then condensed and collected in a reservoir. The pumping system increases the working fluid pressure and sends it to the regenerator for preheating. The preheated liquid then flows to the vaporizer, thus completing the cycle.

The cycle as shown in Figure 2 along with the working fluid state points is used for system operation with heat source temperatures above 750°F. A second version of the system that uses the same basic hardware but operates with a turbine inlet temperature of 465°F at 200 psi is applied to heat streams above 600°F. The design cycle efficiencies are 22.7% and 20.5%, respectively.

The unit is designed for unattended operation. In suitable applications even the startup and shutdown can be performed totally automatically.

SYSTEM DESCRIPTION

The system is a closed organic Rankine cycle using as many off-the-shelf components as possible, creating a state-of-the-art design. The system is a complete package consisting of all the equipment required for startup and unattended operation with the exception of the cooling tower. The equipment supplied by Sundstrand is shown in Figure 3 and consists of the following: 1)

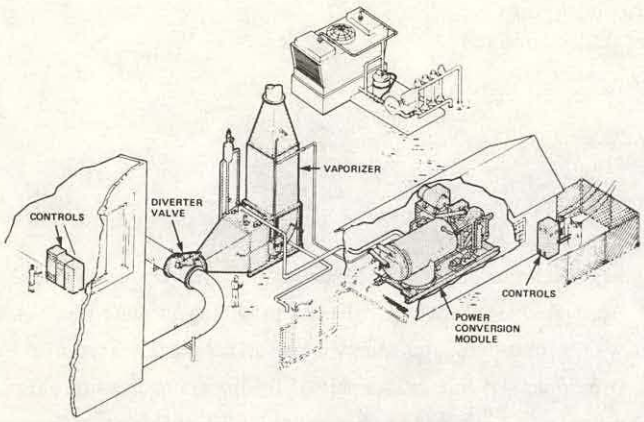


Figure 3. 600 kW ORC System

diverter valve, 2) vaporizer, 3) power conversion module (PCM), and 4) controls.

Diverter Valve

The diverter valve is a three-way, pneumatically actuated valve that controls the flow of the waste heat stream through the vaporizer. During normal operation of the 600 KW ORC, the diverter valve is an active control element, regulating the waste heat flow through the vaporizer, thus maintaining the proper turbine inlet temperature. When the 600 KW ORC is shut down, the diverter valve routes the waste heat stream through the normal exhaust gas path. The valve design is dependent on application and can be a single package or two separate valves.

Vaporizer

The external configuration and internal design of this component are dependent on the application but will generally appear as shown in Figure 4. The vaporizer contains a steel finned tube preheater and boiler of similar construction. The preheater has a multiple pass serpentine counterflow arrangement and is located in the vertical section. The boiler is of a natural circulative design located in the horizontal section. The working fluid exiting the boiler is slightly superheated and enters a centrifugal separator that allows vapor flow to the turbine while recycling the liquid to the boiler. The heat addition to the working fluid will be 11.2 x 10^6 Btu/hr for a 200 psi system or 10.2 x 10^6 Btu/hr for a 300 psi system.

The component design, manufacture, and stamping is in accordance with Section I and Section VIII of the ASME Boiler and Pressure Vessel Code.

Power Conversion Module (PCM)

As the component title implies, this component recovers the energy from the waste heat stream and converts it to usable

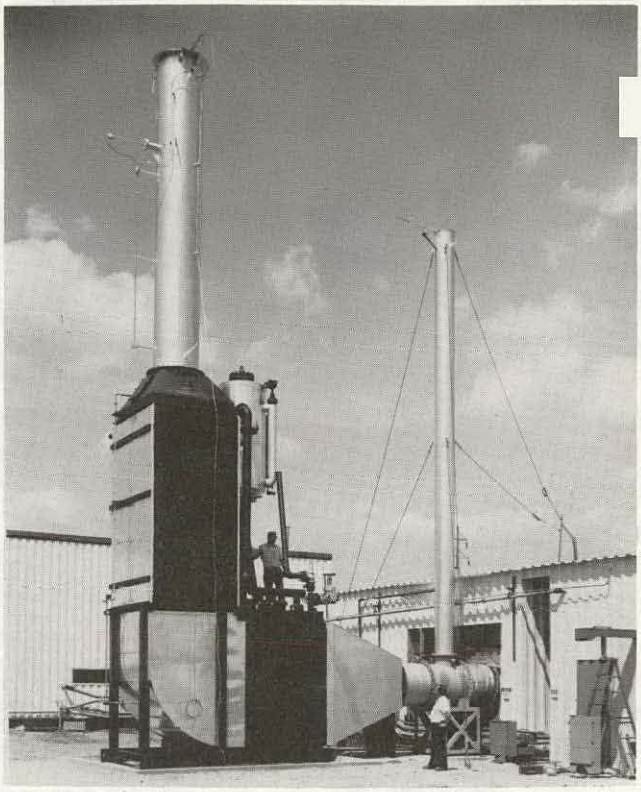


Figure 4. Standard Vaporizer

mechanical power that can be used directly or converted to electricity. The standard PCM, as shown in Figure 5, contains a supersonic impulse turbine with input operating conditions of 200 psi, 465°F or 300 psi, 550°F. These conditions rotate the output shaft at 9,300 or 10,100 rpm, respectively, generating 671 KW of shaft power. A gearbox is employed to slow the shaft to whatever speed is appropriate for the driven equipment.

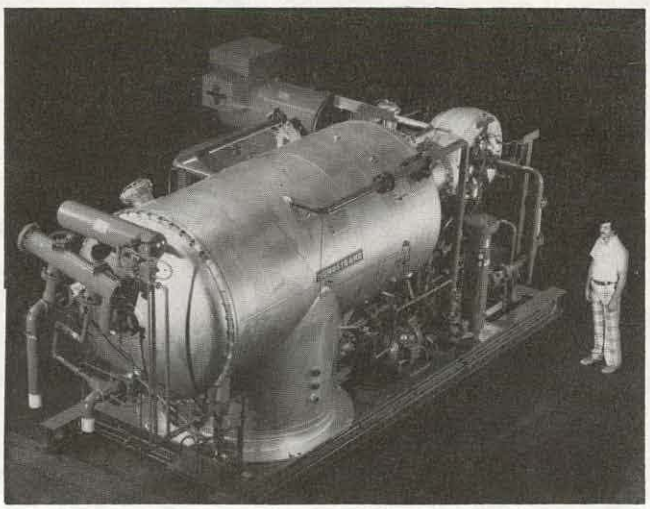


Figure 5. Power Conversion Module

The PCM is also equipped with the condenser/regenerator housi that contains the condenser and regenerator heat exchangers.

These heat exchangers de-superheat and convert the working fluid vapor to a liquid that is collected in the reservoir. The housing and heat exchangers are designed to Section VIII of the ASME Boiler and Pressure Vessel Code.

The pumping system of the ORC engine is also within the boundaries of the PCM. The working fluid is drawn from the reservoir by a boost pump that partially pressurizes the fluid. The final pressurization of the fluid is accomplished by the feed pump. The feed pump is a two stage, back-to-back, vaned impeller contained within the same housing as the turbine and connected directly to the turbine shaft. This combined rotating unit is supported by working fluid lubricated fluid film bearings.

Controls

The control system, as shown in Figure 6, includes the controls for the ORC system as well as the controls for the driven equipment. These allow the system to operate unattended in two modes, infinite bus and finite bus fixed speed.



Figure 6. Controls

Working Fluid

The fluid selection criteria were toxicity, availability, resulting system cost, flammability, and performance; listed in order of importance. Low toxicity and current industrial acceptance were considered to be very important. Availability was a must and some of the more desirable fluids failed this test. The effect of the working fluid on cost included the cost of the fluid itself, any special materials required for construction, and the thermodynamic effects, e.g., heat exchanger size, number of turbine stages, etc. These effects were included in the cost optimization that was carried out for water and the few organic fluids that survived the screening process. The optimization analysis indicated that toluene was the leading contender among organic working fluids and provided a cost effective system. Steam systems remained considerably more costly because of the large waste heat boiler size and complex turbomachinery. Therefore, the decision was made to use toluene as the working fluid. Sundstrand has had considerable experience with toluene, and in addition to having desirable thermodynamic and physical characteristics, it is inexpensive, widely used, well understood, and of low toxicity.

APPLICATIONS

The Sundstrand 600 KW ORC has been designed to be as flexible as is practical with respect to application. The vaporizer, diverter valves and controls can be readily adapted to a wide variety of heat sources. The driven equipment can be selected to meet the requirements of the user.

One of the initial applications for the 600 KW system has been at municipal utilities. The exhaust gases from large reciprocating diesel engines are very suitable for the ORC unit. The heat source is generally clean and easily accessible, and the vaporizer can be designed for several inches of water pressure drop without upsetting the engine efficiency. The gas turbine exhausts are equally attractive for use with the ORC system. There are a number of diesel engines and gas turbines operated by municipal utilities and natural gas pipe line compressor stations which are potentially good applications for the ORC system.

Several other applications have been examined where the exhaust from an industrial process is used as the heat source. Each of these applications has its own set of constraints and unique requirements. One characteristic which is common to most of the industrial applications is the need for a draft fan to make up the additional pressure drop caused by the heat recovery boiler and associated ducting. Some of the other conditions which must be examined are minimum temperature to which the waste heat can be cooled without causing fouling and corrosion of the vaporizer and the characteristics of particulate material in the waste heat stream. These properties must be taken into account in the vaporizer design and construction.

Some of the industrial applications with good potential for heat recovery are cement kilns, ceramic kilns, glass furnace, refractory kiln, foundry furnace, solid waste incinerators. In addition, the operating temperatures of the Sundstrand system are such that it is ideally suited for solar power using concentrating collectors.

FIELD TEST PROGRAM

An organic Rankine cycle unit for waste heat recovery from various sources has been developed and built by Sundstrand Energy Systems under a jointly funded program with the U. S. Department of Energy. This cooperative agreement between

Sundstrand Energy Systems and the U. S. Department of Energy also provides for installing five field test units at various municipal utilities and industrial sites.

The first development system is installed at Sundstrand in Rockford, Illinois. It is a full 600 KW unit operating in parallel with the utility. The unit has accumulated over 7,200 hours and has generated over 3,727,000 KWH.

The field test program is designed to prove the technical and economic viability of the 600 KW ORC unit for various waste heat recovery applications. The first three of these field test units have been installed in municipal utilities to recover energy from diesel engine exhausts. The fourth unit is being installed at a ceramic kiln and the fifth one is slated for a glass furnace.

The five field test sites and units with their performance as of February 1980 are described below briefly.

1) Municipal Power Plant, Beloit, Kansas

The waste heat source is the exhaust from two dual fuel engines. The installation is shown schematically in Figure 7. The generator operates in parallel with the main grid. The unit has accumulated over 6,000 hours of operation and has generated over 2,500,000 KWH.

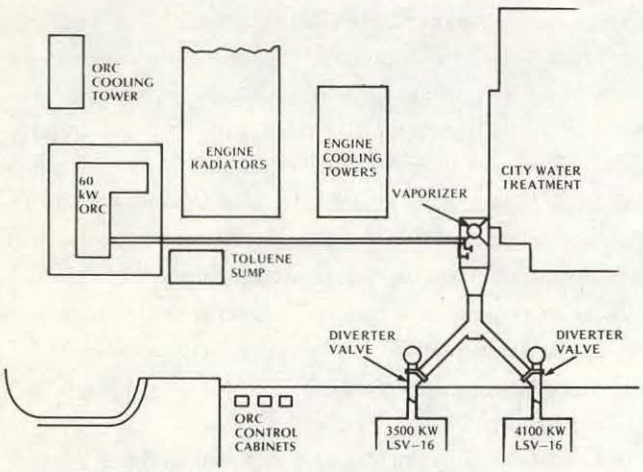


Figure 7. Installation of 600 kW at Beloit, Kansas Municipal Utility

The system parameters are as follows:

Heat Source

Engine make - Cooper Bessemer
Size (BPH) - 4,910 and 5,744
Exhaust temperature - 821°F

Vaporizer

Pressure drop - 7 in W.C.
Flow rate - 94,237 lb/hr

Power output

Electrical - 600 KW

2) Municipal Power Plant, Easton, Maryland

The unit is connected to two large diesel engines; however, it can produce full power from exhaust from one engine only. The installation is shown schematically in Figure 8. The generator is tied to the main grid in parallel. The power plant is operated by remote control from the main power plant located a few miles away. During normal running there are no operators present at the ORC installation. The unit has accumulated over 1,100 hours and has generated over 520,000 KWH.

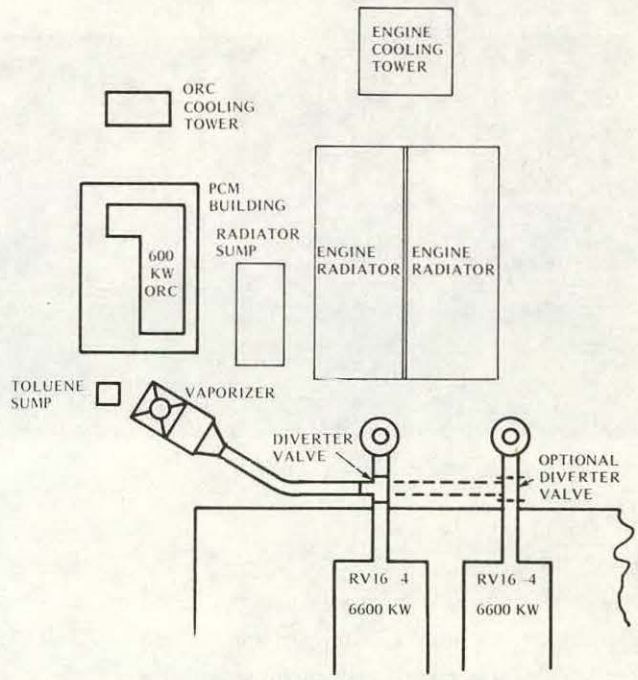


Figure 8. Installation of 600 kW ORC at Easton, Maryland Municipal Utility

The system parameters are as follows:

Heat source

Engine make - Delaval
Size (BHP) - 8,658
Exhaust temperature - 752°F

Vaporizer

Pressure drop - 7 in W.C.
Flow rate - 99,932 lb/hr

Power output

Electrical - 600 KW

3) Municipal Power Plant, Homestead, Florida

This unit is also connected to two large diesel engines as shown in Figure 9. Full power can be developed from one engine exhaust only. The installation has just been completed and the unit will be started shortly.

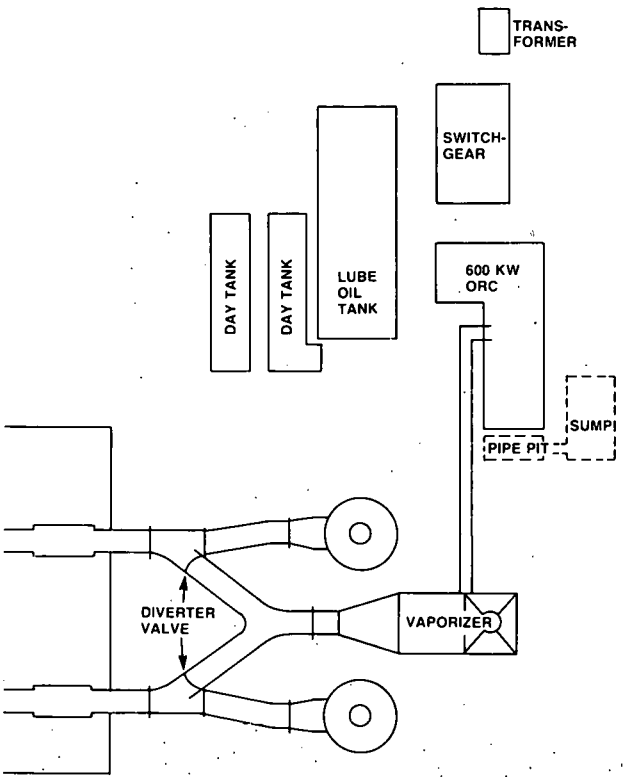


Figure 9. Installation of 600 kW ORC at Homestead, Florida Municipal Utility

The system parameters are as follows:

Heat source

Engine make - Delaval
Size (BHP) - 12,216
Exhaust temperature - 752°F

Vaporizer

Pressure drop - 7 in W.C.
Flow rate - 128,229 lb/hr

Power output

Electrical - 600 KW

4) Crane Company, Ferguson, Kentucky

The ORC unit has been designed to recover heat from ceramic kilns. The installation is shown schematically in Figure 10. The unit is connected to several ceramic kilns. A draft fan has been provided to overcome the pressure drop in the ducts without upsetting the kiln pressure. Each kiln can be individually controlled with dampers and butterfly valves. The generator has been designed to operate in parallel to the utility under normal conditions; however, during utility brownout or blackout the nonessential loads at the ceramic plant are dropped, and the generator switches to stand alone mode to service the essential loads of the kiln.

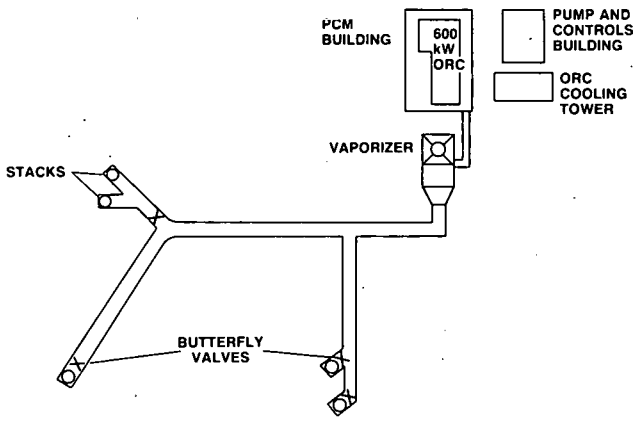


Figure 10. Installation of 600 kW ORC at Crane Co., Ferguson, Kentucky

The design features are as follows:

Heat source

Ceramic kilns
Exhaust temperature - 781°F

Vaporizer

Pressure drop - 2.4 in W.C.
Flow rate - 62,010 lb/hr
Waste gas exit temperature - 336°F

I.D. Fan

Supply pressure - 7.5 in W.C.
Flow rate - 62,010 lb/hr

Power output

Electrical - 680 KW

5) Glass Furnace

The fifth field test unit is designed for waste heat recovery from a glass furnace. The glass furnace exhaust has particulate matter and condensate material which are detrimental to the heat exchanger surface. The vaporizer has a horizontal configuration with a plenum designed for particulate separation. It is also equipped with soot blowers.

6) Solar Irrigation

A sixth site, DOE funded, but not under the same program, is a solar irrigation application. The system was installed in November 1979, and is located in Coolidge, Arizona. The ORC generates 200 KW gross from a modified 600 KW system.

The system parameters are as follows:

Heat source

Heat transfer oil
Temperature - 550°F
Flow - 14,031 lb/hr

Power output

Electrical - 200 KW

ECONOMICS

The amount of saving is dependent on several site specific factors and, therefore, each application must be evaluated individually taking into account specific circumstances. The most significant factors which affect the economics of ORC systems are the cost of electricity, the number of operating hours per year, and the installed cost of the ORC. Figure 11 shows the gross annual savings which will result from the 600 KW ORC system as a function of energy cost and operating hours per year. Figure 12 shows the after tax return on investment as a function of installed cost per KW and gross annual savings.

The assumptions used in calculating the ROI are:

ORC life - 20 years
Depreciation - 16 years DDB
Investment tax credit - 10%
Income tax rate - 50%
Inflation - 8%
ORC maintenance expense - $.0015/KWH

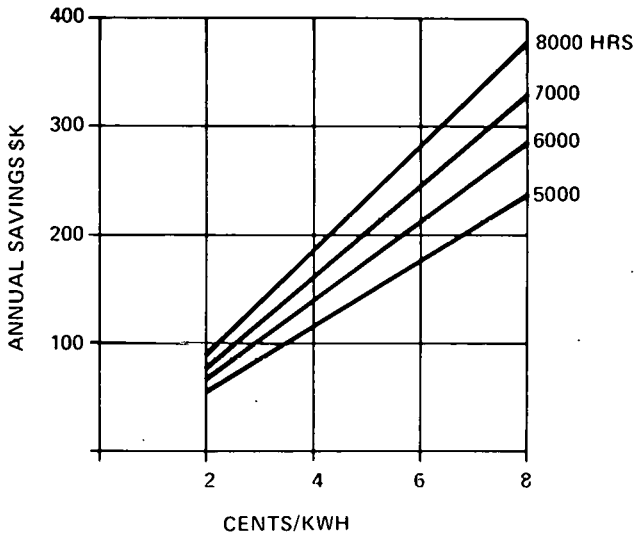


Figure 11. Operating Cost Annual Savings

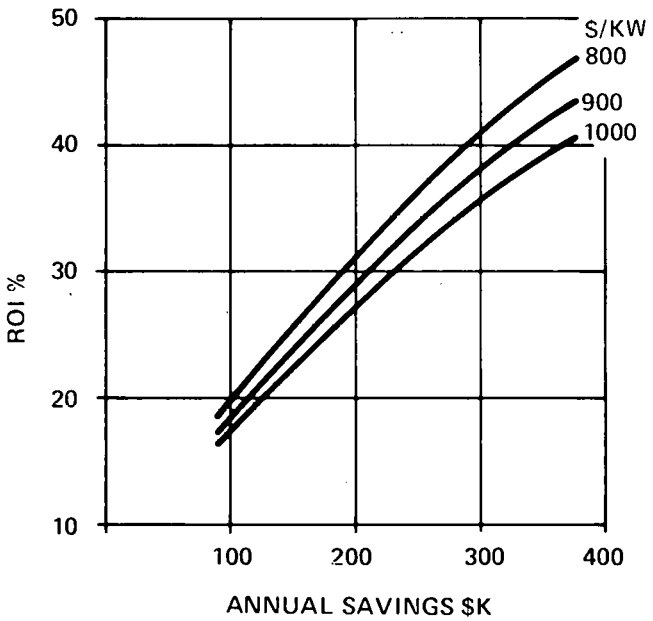


Figure 12. Return On Investment

CONCLUSION

The testing done to date indicates that the 600 KW ORC design is reliable, and exceeds its design performance requirements. As of February 1980, the field test units together with the development unit have accumulated over 15,000 hours of operation. The field test program plus the solar energy program should provide the necessary reliability and operating cost data to allow early introduction of the equipment to the commercial market. In light of the success of the field test program and based on experienc gained so far, the unit is being uprated from 600 KW to 750 KW. Eventually the rating will be increased to 900 KW.

COST-EFFECTIVE WASTE-HEAT ORGANIC RANKINE CYCLE APPLICATIONS AND SYSTEMS DESIGNS

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ABSTRACT

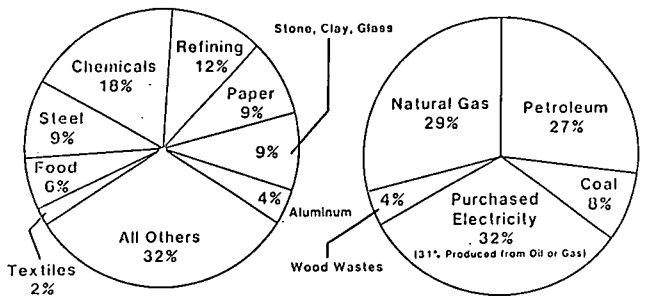
Conceptually, the Organic Rankine Cycle (ORC) power cycle has been well known to the engineering community for many years. Despite the rapid escalation of energy costs during the past decade, and a concerted, though somewhat belated, effort towards industrial energy conservation, very few industrial ORC systems have been installed. The level of technical interest on the part of potential users is high and cannot be blamed for the lack of installations to date. Technical risks are low with systems becoming commercially available. The authors feel the key to increased usage of ORC systems for industrial energy conservation lies in combining cost effective ORC system designs with well selected applications.

It is the intent of this paper to provide those within the process industries with an appreciation of the factors considered by ORC systems designers. The paper then attempts to provide a simple framework, admittedly crude, to assist those attempting to identify and rank order potential ORC applications within their process plant or company.

BACKGROUND

The industrial sector as shown in Figure 1 consumes about 37% of our total U. S. energy supply.

FIGURE 1
INDUSTRIAL ENERGY USAGE

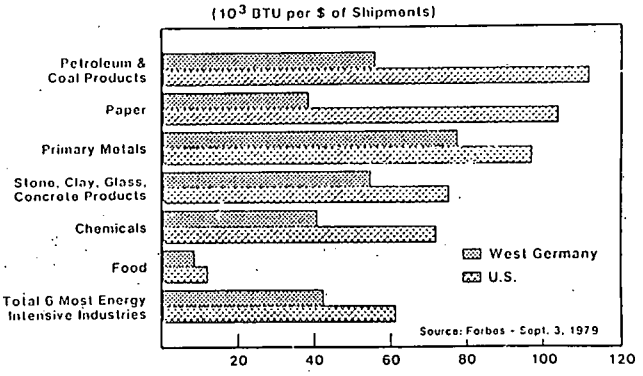


Total 1978 Industrial Consumption was 29 QUADS
(13.7 Million B.O.E.) or 37% of U.S. Total

Source: July 1979 D.O.E. Monthly Energy Review

Most of this energy is derived from rapidly depleting oil and gas reserves and as such will face rapid price escalation relative to labor, capital, and other more abundant resources. These primary industrial fuels will also face more frequent supply uncertainties which result in even more severe, though unpredictable, economic penalties. The consumption of energy by our primary manufacturing industries exceeds that of most other industrialized nations, including West Germany, as illustrated in Figure 2. This is due partially to the fact that they faced higher priced imported energy costs earlier than in the U. S. and also because of a heavier energy intensive primary process content in many U. S. industries (i.e. ore smelting vs. machine tool manufacture, export pulp vs. fine paper production, or basic resins vs. textile fiber production).

FIGURE 2
U.S. VS. WEST GERMAN INDUSTRIAL ENERGY USAGE
(10^3 BTU per $ of Shipments)



During the last decade the real price (in constant dollars) of energy has about doubled relative to the cost of other goods and services. Consumers who previously spent about 8% of their after taxes income on energy, now spend about 15%, with the nation as a whole spending over 10% of its Gross National Product on primary energy. Energy costs now represent from 5 to 50% of the delivered price of industrial goods.

When one considers that industrial profits average only 5% of the selling price of industrial goods, it becomes obvious that economical purchase and use of industrial energy will have profound effects on the profitability and competitive position of most manufacturing firms.

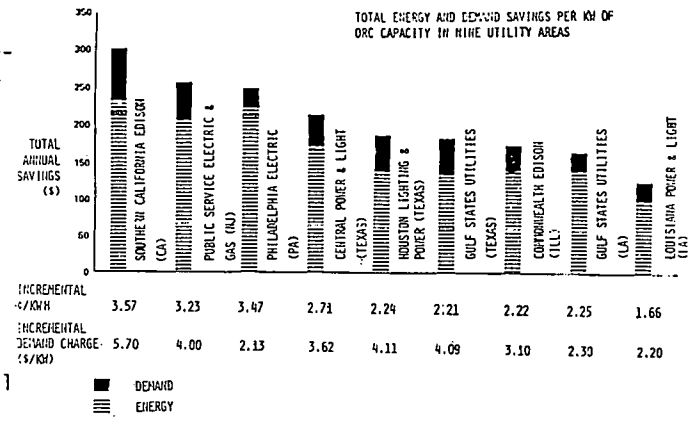
From a national energy policy standpoint, investment in both industrial and consumer energy conservation are the most cost effective energy investments available to our nation. One billion dollars invested in home insulation or industrial conservation will save more energy than one billion dollars invested in new primary energy production, and perhaps several times more than an investment in capital intensive renewable sources such as solar. Cost effective use of increasingly scarce investment money is especially important.

Conservation, obviously, cannot solve our entire energy problem since declining fossil fuel production and/or increased industrial growth (if and when it resumes) will necessitate new primary energy production. It can fill the gap, however, over the next 5 to 15 years until synthetic fuels (primarily from coal and shale), followed by renewables, can come to our aid.

ORC systems displace electrical power which has not yet escalated as rapidly as oil and gas. This situation, however, is starting to change. New trends in pricing power, such as incremental pricing (in which industry, rather than consumers pay for the new more expensive power plants), and the removal of declining block pricing which has favored industry, are finding strong favor with legislators and public utility commissions, who realize that inflation hit consumers have more political impact than industrial firms. Additionally, the cost of highly unionized coal will likely keep pace with price increases in oil and gas. Incremental pricing will pass the higher cost of new lower efficiency scrubber equipped coal fired plants to industry rather than consumers. The de-facto moratorium on new nuclear plants will offer little relief.

Utility rates displaced by ORC systems vary considerably across the country as shown in Figure 3. Note that demand or capacity related charges generally run from 15 to 25% of power costs. New laws, such as the Public Utility Regulation Policy Act, will require utilities to credit industrial self generators for both displaced energy and demand charges as well as requiring them to provide backup power at reasonable rates. This new law will probably take 12 - 24 months to implement at the state public utility commission level, but will make ORC systems look more attractive by increasing displaced power cost. The Energy Tax Act provides an additional 10% investment tax credit for conservation equipment, which are believed to include ORC systems, further improving their economic attractiveness. Accelerated depreciation of ORC systems, if allowed, could attract more investment capital into ORC systems.

FIGURE 3



THE ROLE OF ORC SYSTEMS IN INDUSTRIAL CONSERVATION

ORC systems are intended to recover and convert otherwise unusable low grade heat into a useful energy form, namely power. In the design of new facilities or in contemplating modifications to existing ones, first priority should go to minimizing the amount of low grade heat produced. This can be done by recognizing the increased economic value of high grade heat (high temperature or low enthropy). Carpenter and Thomas (1) propose designing heat recovery equipment in chemical process plants using varying energy costs based on their Second Law potential value. A BTU escaping from a high temperature pipe costs more than one escaping from a lower temperature one since heat loss (or temperature degradation) from high temperature sources reduced the possible use of that heat for subsequent lower temperature purposes. Even with the most efficient cascading of heat, however, a portion eventually is reduced to a temperature where no in-plant use for it exists. At this point, the only option remaining is to convert this heat into something which can be used, such as electrical power via an ORC. Alternatively, if the process plant has a high heat requirement at temperatures only slightly above

the heat rejection temperature, heat pumping (possibly using an ORC prime mover) might make economic sense. As pointed out later in this paper, at today's power costs, only a portion of low grade waste heat streams can make cost effective use of ORC systems though this portion will increase substantially over the near term.

PROMISING ORC MARKETS

A recent D. O. E. study identified 2,073 MW_E of electrical power, which could be technically and economically produced by ORC systems from six industries surveyed (Figure 4). The vast majority of the

FIGURE 4
EXISTING COST EFFECTIVE MARKET FOR ORC MACHINES

Industry	Market Size (mw)	Energy Saved (BPDE X 10^3)	% of Total Market
Petroleum	1407	56.8	67.9
Chemicals	554	22.3	26.7
Stone, Clay, Glass	81	3.3	3.9
Paper	2	0.1	0.1
Primary Metals	29	1.2	1.4
Total	2073	83.6	100.0

Source: Resource Planning Associates 12/78

applications identified by this study were in the refining and chemical industries and are listed in Figure 5. Other applications such as diesel and turbine exhausts from mobile uses like marine engines, and stationary uses such as transmission pipelines, may also have merit.

FIGURE 5
TECHNICAL MARKET POTENTIAL AND ENERGY SAVINGS FOR ORGANIC RANKINE CYCLE BOTTOMING SYSTEMS

INDUSTRY	PROCESS	SYSTEM SIZE RANGE (KW)	TECHNICAL MARKET POTENTIAL (MW)	ENERGY SAVINGS (BPDE)
PETROLEUM REFINING	CATALYTIC REFORMING	1,000-8,000	674.6	27,220
	HYDROTREATING	600-2,700	285.7	11,528
	VACUUM DISTILLATION	600-9,500	275.1	11,100
	ATMOSPHERIC DISTILLATION	600-7,500	213.5	8,615
	HYDROGEN MANUFACTURING	600-7,500	115.2	4,648
	FLUID CATALYTIC CRACKING	600-2,500	59.3	2,393
	HYDROCRACKING	600-3,400	54.4	2,194
REFINING TOTAL			1,677.8	67,698
SULPHURIC ACID	CONTACT	615-11,469	233.3	9,414
STYRENE	DEHYDROGENATION	2,886-54,113	369.8	14,921
POLYETHYLENE	POLYMERIZATION (WET)	4,687-14,802	55.5	2,239
ACETALDEHYDE	TWO-STEP OXIDATION	26,817-44,695	71.5	2,885
AMMONIA	SYNTHESIS	659-9,003	183.3	7,396
CHEMICALS TOTAL			913.4	36,855

To date, the few industrial ORC systems currently operating or being installed in the U. S. are not in the refining or chemical markets identified as the primary future market by the study referenced above. Most initial systems have gone on to municipal diesel generating stations. Other initial ORC applications have gone on high temperature waste heat streams which produce higher ORC power outputs, but are becoming increasingly scarce (and rightfully so) in the primary process industries as energy cascading becomes more widespread.

ORC SYSTEM DESIGN CONSIDERATIONS

ORC heat recovery systems are a classical case of displacing energy (and operating expense) with capital. Well designed ORC systems should provide unattended operation and minimal routine annual maintenance. The economic viability of an ORC application, therefore, depends primarily on two factors:

1) the total installed cost of a system (including equipment, installation, and both consumer, and vendor engineering;
2) the most likely future power savings,

Predicting the likely power savings of a proposed ORC system involves substantial uncertainty. One can be assured, however, that power costs will raise faster than the general rate of inflation. Power costs will also increase faster than the cost of ORC systems thus increasing their future attractiveness. This paper will not attempt to deal with predicting future power costs, but it should be noted that using current power rates in evaluating a potential ORC investment is unrealistic.

While many competent engineers can "put together" an ORC design from available components, designing systems which can be economically employed requires a combination of multiple unit production and a rigorous optimization approach to design seldom required of other equipment systems. This section discusses primary considerations facing the ORC system designer. It is not intended to be comprehensive, but rather to give potential users some appreciation of the designers task.

STANDARDIZED AND PREASSEMBLED VS. CUSTOM DESIGNED AND FIELD ERECTED UNITS

The choice between these entirely different design approaches will often have a great impact on unit cost (installed cost per KW capacity) than any

other design factor. Standard design and preassembly of ORC units results in savings in multiple unit manufacture and component purchasing as well as common engineering. Installation costs will also be less provided unit size permits shipment in one or two assembled units. Preassembled units normally will have slightly lower efficiences due to design compromises necessary for standardization. Another advantage of standard designs is improved reliability through repeat designs. Generally one would have to use very large ORC systems (i.e. over 2,000 KW) in low construction cost areas to compete with standard packages. Most packaged systems offered today are in the 300 to 600 KW size range leaving a gap between those initial packaged systems currently offered and the minimum sized custom designed systems which might prove cost effective.

UNIT SIZE

As previously shown in Figure 5, in refinery applications, waste heat streams of up to 8,000 KW potential exist. A few streams in chemical processes are even larger. For individually designed and constructed units, cost is strongly effected by unit size. One study (2), for example, found that in a system designed for a 300°F liquid stream a 30 mm BTU/hour system (approx. 1,000 KW) was 24% more expensive than a 100 mm BTU/hour system and a 10 mm BTU/hour system cost 74% more. Such studies, however, do not address the savings possible through multiple unit design and manufacture which can save 25% or more. For preassembled units, installation costs, which can otherwise equal machinery costs, are also substantially reduced.

SIMPLE VS. COMPLEX CYCLES/WORKING FLUID SELECTION

The designer must constantly chose between simple cycles and more complex cycles which can provide greater efficiency at the expense of system complexity and higher cost. For example, binary cycles (employing two working fluids and two turbines) can improve efficiencies of system operating on waste streams of 500°F to 700°F, but are clearly not cost effective on systems operating below this range. The use of superheat, reheat, and staged cycles can, in certain circulstances, improve cycle efficiencies, but are often not cost justified.

It is usually beneficial to select a working fluid, from the many candidates available, which avoids condensing conditions during expansion, thus simplifying both evaporator and turbine design. Several fluids have temperature/entropy characteris tics which allow a relatively close approximation of the ideal Carnot Cycle thus improving efficiency. Fluids must also be chosen for convenient working pressures at the boiling and condensing temperatures dictated by the application. The useful temperature range of standardized ORC systems can often be quite broad due to the many different working fluids available.

Cycle efficiency can vary from 50% of ideal Carnot efficiency for simple cycles, to over 70% for complex cycles also combining large heat transfer areas. It is seldom obvious which choices yield the lowest cost per installed KW.

TURBINE SELECTION AND DESIGN

A wide range of turbines have been proposed for ORC use. Generally high speed radial or mixed flow units produce higher turbine efficiencies (up to 80% of theoretical). Such units, however, require high speed gear reducers to match generator speeds which add cost and forfeit a portion of their efficiency gains. Low speed single stage impulse type turbine which can direct drive generators can achieve turbine efficiencies exceeding 65% on most of the heavy fluids typically used in ORC systems. Such turbines also simplify seal and bearing designs.

LOW VS. HIGH TEMPERATURE APPLICATIONS

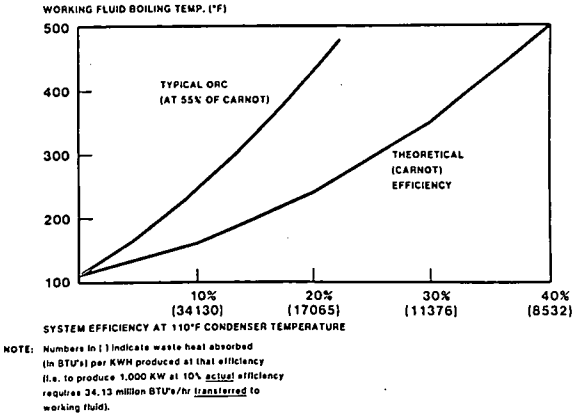
Like conventional steam power plants, ORC systems can achieve 50 to 70% of their ideal Carnot efficiency. The Carnot efficiencies, of low temperature sources, however, are substantially reduced, and actual cost effective design efficiencies are probably only about 55% of the Carnot efficiency (see Figure 6). Also the waste heat stream must be significantly hotter than the boiling working fluid to reduce heat exchanger surface area requirements to acceptable levels.

Higher temperature sources could help, but they usually offer other cost effective recovery opportunities such as feedstock or combustion air preheating. Figure 7 shows the distribution of rejected heat identified in a recent D. O. E. survey. This curve will probably shift to the left as energy prices co tinue to climb.

Many existing nonutilized higher temperature streams present problems of heat exchanger corrosion

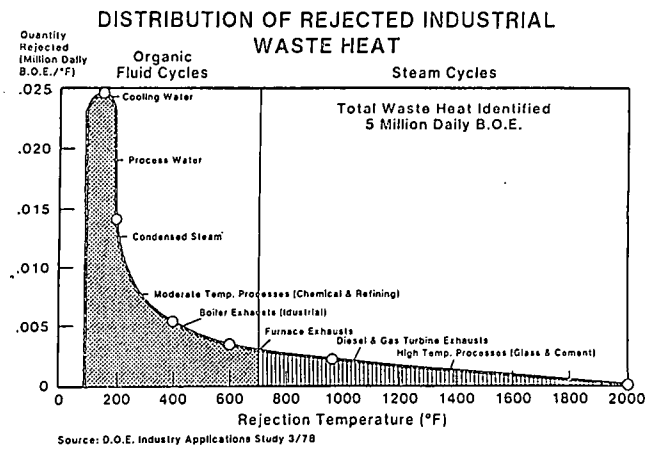
or fouling which precluded prior recovery. It is, therefore, anticipated that most ORC systems will be used on lower temperature waste heat streams which offer no such alternatives.

FIGURE 6



NOTE: Numbers in [ ] indicate waste heat absorbed (in BTU's) per KWH produced at that efficiency (i.e. to produce 1,000 KW at 10% actual efficiency requires 34.13 million BTU's/hr transferred to working fluid).

FIGURE 7



Source: D.O.E. Industry Applications Study 3/78

AMOUNT OF WASTE HEAT UTILIZATION

To get the highest utilization out of a waste heat stream, one system designer might attempt to cool the stream to a temperature approaching the working fluid condensing temperature. He must choose an ORC boiling temperature significantly below the waste heat temperature so boiling will proceed as the waste stream gives up heat and looses temperature, such as approach is illustrated in Figure 8.

An alternative design (Figure 9) would be to use a lesser portion of more waste heat, allowing larger temperature differentials for both the condenser and evaporator/preheater (cheaper heat exchangers) which also result in more KWs out of the same machine.

While the latter system utilizes only about 25% of the available stream temperature (and heat), (vs. 85% for the former system) it will produce twice the power out of a machine of about the same cost. In many situations this could spell the difference between an economical application and none at all. It is often better to "waste" some waste heat than to make a futile attemot to recover it all.

FIGURE 8

HEAT SOURCE & WORKING FLUID TEMPERATURES-HIGH UTILIZATION

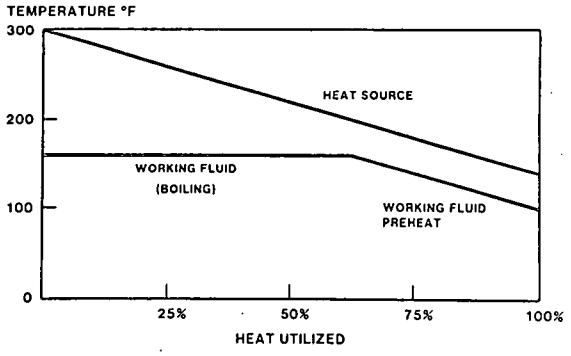
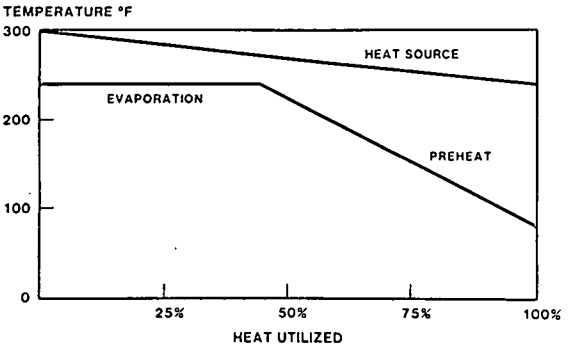


FIGURE 9

HEAT SOURCE & WORKING FLUID TEMPERATURES-LOW UTILIZATION



CONDENSING MEDIUM

Many process plants are gradually shifting to more air cooling at the expense of water cooling. Since air cooled condensers require 50 to 60°F higher Rankine cycle condensing temperatures, the effect on ORC output (and cost/KW) is significant. On a 300°F waste stream producing a 200°F boiling point, it would reduce net output by over 25% and increase costs correspondingly.

LIQUID, CONDENSING, OR GASEOUS HEAT SOURCES

While selecting heat sources are outside the province of the ORC system designers, they will have a profound effect on the feasibility of a given application. For a given source temperature, condensing low pressure stream usually presents the most economical applications followed by non-corrosive liquids, partially condensing hydrocarbons, and lastly, clean flue gasses. Corrosive or fouling liquids and dirty flue gasses are avoided by most ORC system suppliers given the multitude of easier applications which present themselves today.

RANKING POTENTIAL ORC APPLICATIONS

At the risk of over simplification, the last section of this paper will attempt to propose a system for rank ordering potential ORC applications by their probable economic viability. Once potential applications are so ordered, a more detailed application analysis is justified. Such an analysis requires substantial effort for both the potential user and suppliers, thus it is productive to start with your best application prospects first. Standardized designs which permit some degree of adaptability, make system evaluation and costing somewhat easier. Computer simulation can permit analysis of a wide range of alternatives for a given application with some assurance of approaching system optimization.

For purposes of rank ordering potential applications, we have chosen a typical application of a 1,000 KW system operating on a 350°F noncorrosive liquid hydrocarbon. We have assumed that about 60% of the heat (relative to 100°F ambient) in the liquid stream is utilized, and it exits at 200°F. The boiling point is about 280°F and the condenser (water cooled) operates at 110°F. We have arbitrarily assigned this unit a relative cost of 1.0 ($/KW installed).

BASE MACHINE PARAMETERS

Machine Installed Relative Cost	1.0
Size	1,000 KW Output
Design Approach	Standard-Mult. Unit
Source Type	Hydrocarbon Fluid
Source Temperature	350°F
Condenser Temperature	100°F(Working Fluid)
Source Heat Utilization Rate	60%(200°F Exit Temp.)
Condenser LMTD	10°F
Evaporator/Preheater LMTD	60°F
Special Installation Factors	None

GROSS EFFECTS OF DESIGN PARAMETERS ON UNIT COST

1. Machine Size

Machine size has a significant effect below 1,000 KW units with a lesser effect above 1,000 KW size.

Adjustment factors:

Below 1,000 KW Cost Ratio = (Size Ratio)$^{.6}$

Above 1,000 KW Cost Ratio = (Size Ratio)$^{.8}$

2. Type of Waste Heat Sources

Assuming the same source temperature, the following reflect approximate cost adjustments due to evaporator/preheator cost variation and installation of same:

Hydrocarbon liquid	no cost adjustment
Condensing Steam	25% reduction
Hot Water	10% reduction
Condensing hydrocarbon (due to installation complexity)	10% increase
Flue gas (due to surface area & installation)	35% increase

3. System Design Approach

The choice between a multiple pre-engineered shop assembled unit (if available) and a custom designed field constructed unit can be substantial. It is unlikely that pre-assembled units above 1,000 to 1,500 KW will become available due to shipping considerations. Installation costs are highly site specific.

1. 10 or more pre-assembled/ pre-engineered units	no adjustment
2. Single custom engineered preassembled	20% over base case
3. Single site assembled, custom engineered	30% over base case

4. Source Temperature and Condenser Temperature

Source temperature, source utilization rate, and evaporator surface area are key ways to effect working fluid boiling point which is the key factor determining the output of a given machine. Actual machine output is proportional to (but significantly lower than) Carnot efficiency. For a given source utilization rate (i.e. extracting 60% of the available level) and given machine, the effect of source temperature and condenser temperature on output can be approximated by the following:

$$\text{Cost Adjustment} = \frac{\text{Base Source Temp}(350^\circ\text{F}) - \text{Base Condenser Temp}(100^\circ\text{F})}{\text{New Source Temp} - \text{New Condenser Temp}}$$

Normally air cooled condensers condense about 50°F cooler (i.e. 150°F to 160°F) than water cooled unit (i.e. 100°F to 115°F).

5. Heat Utilization Rate

As illustrated previously, one can increase the boiling temperature and therefore machine efficiency and output by decreasing the percent of heat extracted from a given waste heat source. In the extreme, we would use a very small percent of very large stream with the practical limitation being the minimum cost effective mean temperature difference between the source and

working fluids (typically about 15°F for water, 25°F for liquid hydrocarbons, and 50°F to 75°F for flue gases). The precise effect on output of a given sized unit (and hence cost) varies with working fluid selected, but three approximate cases are listed below. One hundred percent utilization is defined as the difference between source temperature and condenser temperature.

@40% waste heat source utilization-25% cost decrease
@60% waste heat source utilization-no adjustment
@80% waste heat source utilization-75% cost increase

For condensing sources, this possibility of significantly improving ORC economics via lower utilization does not exist.

6. Condenser and Evaporator Surface Area (LMTD) Changes

Increases or decreases in the surface area in the evaporator or condenser will increase both unit costs and output. It is not easy to predict which will rise faster, but if the original design is economically optimized, movement from this design point will increase cost per KW of output. In our base case the evaporator/preheater and condenser each represent about 15% of system installed cost. If we doubled the size of each, thus reducing the LMTDs to 25°F and 5°F, respectively, costs would increase by about 30%, and output would rise 25% for a slight net cost increase. Reducing the size of both exchangers by 50% would have a more serious negative cost impact.

7. Special Installation Factors

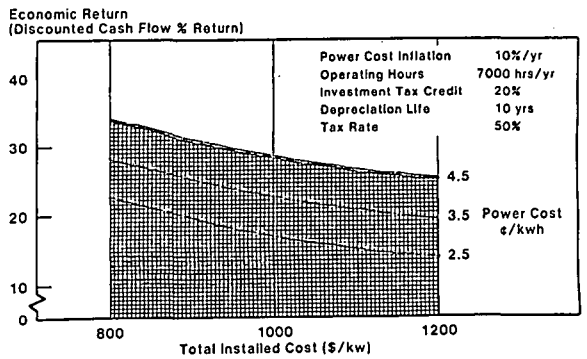
Installation of preassembled systems will typically cost from 30% to 50% for liquid or condensing vs. flue gas systems, respectively. Site assembled systems are most costly. Both of these effects are included in 2 and 3 above.

Installation complexities such as elevated mounting; long waste heat or condenser piping runs; high corrosive, errosive, or fouling conditions, etc. can easily double installation costs. Local labor productivity and work practices can likewise double installation expense. Special alloys when required can double the cost of the evaporators or condensers with cost impacts as indicated in 6 above.

UNIT COST

The above cost factors should provide some assistance in rating the relative attractiveness of various ORC applications. The D. O. E. study of ORC systems referenced earlier suggested that the installed unit cost for the above reference system might range from $800 to $1,000 per KW adjusted for 1980 dollars. Figure 10 provides a means of estimated the economic return of an ORC project based on the displaced power cost and tax assumptions as stated. It is important that the actual or likely displaced power is determined, which may involve discussions with your utility. Increasing or decreasing the operating hours per year has a linear effect comparable to adjusting installed cost per KW.

FIGURE 10
ORC SYSTEM RETURN ON INVESTMENT



Summary

Cost effective ORC applications exist today. As power generation costs and industrial power pricing policies outpace the cost of producing ORC systems, more applications will become cost effective. The systems are made up of well proven standard components, and several vendors have initial units in commercial demonstration. System standardization and multiple unit manufacture will further reduce costs and improve reliability. Standard units of 300 to 600 KW are commercially available today from several suppliers. Larger preassembled units currently under design will provide improved economies.

Property selected applications in medium to high cost power regions can yield acceptable economic returns today using either very large scale custom systems or those packages systems commercially available. Complex custom systems seeking to recover every available BTU, while technically elegant, may not always be cost effective especially when installation difficulties are present. Simple turbine cycles, low to moderate waste heat utilization rates, and economical heat exchanger surface area selections can yield attractive economics especially on condensing steam, hot water, and liquid hydrocarbon applications which generally involve installation simplicity.

References

1. D. J. Carpenter and D. J. Thomas, Oil & Gas Journal, (January 28, 1980) p. 137-148.
2. Industrial Markets for ORC Bottoming Systems, prepared by D.O.E. by Resource Planning Associates, Inc., 1979.

LOW LEVEL HEAT RECOVERY THROUGH HEAT PUMPS AND VAPOR RECOMPRESSION

By J. Gilbert

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Latham, New York

ABSTRACT

The intent of this paper is to examine the methods and economics of recovering low level heat through heat pumps and vapor recompression. Actual commercially available equipment is considered to determine the near-term and future economic viability of each approach as a function of the source and sink temperatures and magnitude of heat flow.

Generic heat pumps and vapor recompression designs are explained, costed, estimated in performance, and evaluated as a function of the economic parameters such as local utility and fuel rates, hours of operation, investment tax credits, and other standard investment variables. The results are presented in a manner that permits simple economic evaluation of these technologies.

Those of you who have considerable background in heat pump principles may find this presentation overly simplistic. It is the author's contention that the energy economics are more critical to the incorporation of heat pumps into plant designs than detailed design calculations. Consequently, the presentation to follow will start out with a brief primer on economic analysis, describe the basic heat pump cycles and then develop the energy savings achieved through their use in a distillation column. While general guidelines for equipment cost are offered, it must be remembered that installation costs are very site specific and potentially represent the lion's share of the total project cost. With these considerations in mind, we proceed.

THE ECONOMICS OF LARGE ENERGY CONSERVATION PROJECTS

This analysis is very general in nature and would apply to most capital-intensive energy conservation projects. The results provide a rapid, accurate prediction of financial attractiveness. The measures used to summarize the attractiveness are after tax payback period and the project internal rate of return (IRR). Another equivalent to the IRR is the project discounted cash flow (DCF).

In general, an energy conservation project may be described as an investment in capital equipment that produces savings beyond the operating costs yielding a return on the use of funds. The following parametric factors were included in this financial model:

Capitalized Cost. The total cost of energy conservation equipment including installation, process modifications and related costs.

Energy Savings. The annual value of the energy saved including credits for reduced cooling water or increased plant production capacity.

Depreciation Charges. The depreciation charges based upon equipment life and standard schedules.

Operating Costs. The annual costs associated with operating and maintaining the equipment including labor, materials, taxes and insurance. The rise in operating costs is also considered. Operating costs have historically risen more slowly than energy costs.

Table 1 illustrates a typical economic analysis for a $1 million conservation project that is anticipated to return $350,000 in savings in the first year of operation. These returns have been assumed to rise at 10% per year. The operating and maintenance costs are estimated at 7% of capitalized cost (i.e., $70,000) and are expected to rise at 8% per year. This company's depreciation method is sum of the years digits with a 10-year asset life. The project is to be evaluated over a 10-year period.

Notice that the 20% investment tax credit is taken in the year the equipment is purchased. The next year, $350,000 in energy savings was achieved, depreciation charges of $182,000 were allocated and $70,000 in operating and maintenance charges were incurred yielding earnings before interest and taxes (EBIT) of $98,000. Assuming a marginal income tax of 50%, the after tax profits are $49,000. Cash flow consists of after tax profits plus depreciation charges totaling $231,000 in this year.

The discounted cash flow represents that percentage satisfying the following equation:

TABLE 1

SAMPLE INVESTMENT ANALYSIS

Year	Eqpt Bal	Savings	Deprec	Op & Mnt	Ebit	Aftax	Cash Flow	Cum Cfw	DCF
0	1000	-	-	-	-	200	(800)	(800)	-
1	818	350	182	70	98	49	231	(569)	( )
2	655	385	163	76	146	73	236	(333)	(-)
3	509	424	146	82	196	98	244	(89)	(-)
4	382	466	127	88	251	126	253	164	7.8
5	273	512	109	95	308	154	263	427	15.8
6	182	564	91	103	370	185	276	703	20.9
7	109	620	73	111	436	218	291	994	24.2
8	55	682	54	120	508	254	308	1297	26.5
9	18	750	37	130	583	292	329	1626	28.2
10	-	825	18	140	667	334	352	1918	29.4

$$\Sigma \text{ Investments (Year i)}\left(\frac{1}{(1.0+DCF)^{i}}\right) =$$

$$\Sigma \text{ Returns (Year i)}\left(\frac{1}{(1.0+DCF)^{i}}\right)$$

which for this example can be simplified to (for 4 years):

$$800 = \sum_{i=1}^{4} \text{Returns (Year i)}\left(\frac{1}{(1.0+DCF)^{i}}\right)$$

$$= 231\left(\frac{1}{1.078}\right)^{1} + 236\left(\frac{1}{1.078}\right)^{2} + 244\left(\frac{1}{1.078}\right)^{3}$$

$$+ 253\left(\frac{1}{1.078}\right)^{4} = 214 + 203 + 195 + 188 = 800$$

Consequently 7.8% is that discount rate that equivalences that current expenditure of $800,000 with the first four years of after tax savings. Notice that the DCF rises very quickly at first and then very slowly. This rapid rise can cause a project that is attractive on a 10-year horizon to be shown quite unattractive in the 6-8 year time frame.

Another common measure of financial attractiveness is the after tax payback period, or that period of time in which the cumulative cash flow is zero. DCF is more indicative of long-term comparative performance. The after tax payback period is related back to a simple payback and relative energy escalation rate in Table 2. Simple payback is defined as the savings (net of operating and maintenance charges) divided by the investment. Notice how inaccurate simple payback calculations are at both extremes.

Before going into the details of heat pump performance and economics, let us look at a simplified categorical description of heat pump types. Illustration 1 outlines four basic heat pump concepts ranging from simple vapor recompression through waste heat driven external refrigerant systems. Heat pump economic performance can be described simply through the well-known parameter, coefficient of performance:

$$COP \equiv \eta_m \eta_f \left(\frac{460 + T_\beta}{T_\beta - T_\alpha}\right)$$

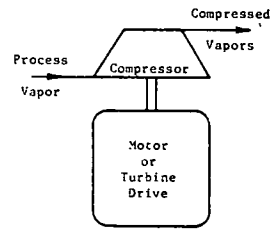
where T_α and T_β are the heat source and heat user temperatures (°F), and η_m and η_f are the mechanical equipment and fluid thermodynamic efficiencies, respectively. Optimal heat pump designs typically achieve a combined thermomechanical efficiency of 70% which is what will be assumed to develop the economic performance charts.

BUT HOW MUCH DO YOU SAVE?

Heat pumps are purchased to save money and energy. Since energy is becoming an extremely valuable commodity and may have significantly different values within or external to an individual process, the following discussion focuses on the experienced savings due to pumping one million Btus from T_α to T_β assuming that the energy at T_α and T_β is valued at α and β dollars per million Btus, respectively. The heat pump is assumed to use energy valued at γ dollars per million Btus.

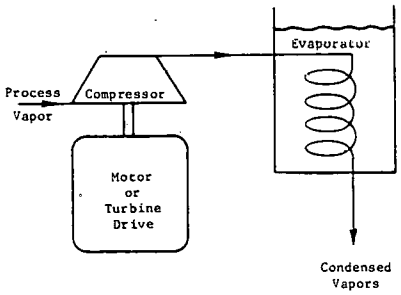
ILLUSTRATION 1

BASIC HEAT PUMP CATEGORIES



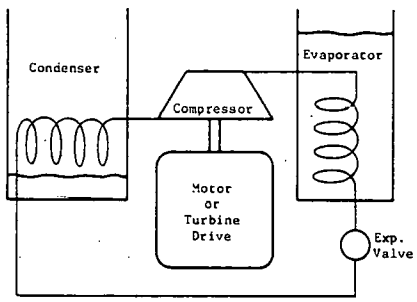
I. SIMPLE VAPOR RECOMPRESSION

Common applications include steam recompression where it is less expensive to compress vapors for reuse in the process rather than to condense and reboil. This category of heat pump represents a minimum capital cost but has the narrowest range of applicability, very often limited by pressure rise or steam purity. After tax payback periods are often just a matter of a few months.



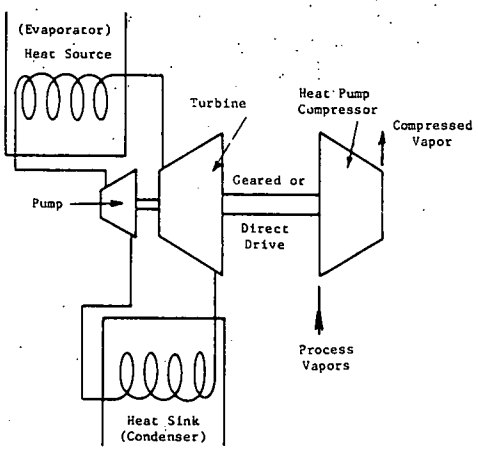
II. VAPOR RECOMPRESSION EVAPORATION

Frequently an attractive alternative to multiple effect evaporators where evaporator vapors are compressed sufficiently to transfer the latent heat to the evaporator upon condensation. This type of heat pump is frequently attractive for distillation towers where overhead condensers and bottoms reboilers are within about 150°F of each other. Polymerization or other reactions may prevent application even when condensers and reboilers are thermally close. This class of heat pumps has frequently shown after tax payback periods of six months to one year.



III. HEAT PUMP WITH EXTERNAL REFRIGERANT (REVERSED RANKINE CYCLE)

This is the most common form of heat pump to come to mind, and is frequently applicable where refrigerated condensers are used and the evaporation load is within about 150°F of the reboiler. These systems are significantly more expensive than simple vapor compression approaches, but do often produce after tax payback periods of one to two years.



IV. RANKINE CYCLE (WASTE HEAT) DRIVEN

Where the heat to be pumped is significantly smaller than the heat available, a Rankine cycle drive may be feasible. While the probability of a match between heat pump and heat source characteristics is lower than the previous categories, and the capitalized cost is the highest, this concept of using "free" waste heat to pump heat often yields after tax paybacks of between two and three years.

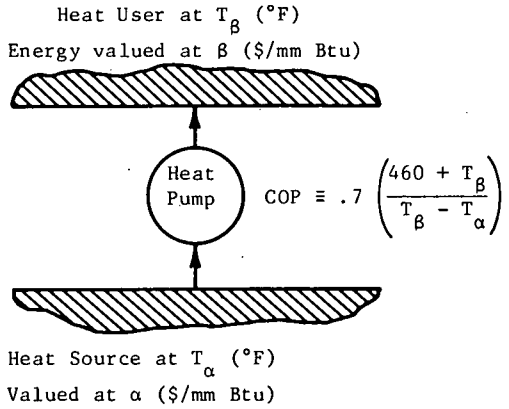
TABLE 2

AFTER TAX PAYBACK PERIOD AS A FUNCTION OF SIMPLE PAYBACK AND ENERGY ESCALATION

Simple Payback (%)	Energy Escalation (% per year) 0	5	10	15	20
10	7.1	6.5	6.0	5.7	5.4
15	5.5	5.2	4.9	4.6	4.4
20	4.6	4.3	4.1	4.0	3.8
25	4.0	3.8	3.6	3.5	3.4
30	3.5	3.3	3.2	3.1	3.0
35	3.1	3.0	2.9	2.8	2.7
50	2.8	2.7	2.7	2.6	2.5
55	2.2	2.2	2.1	2.1	2.0
60	2.1	2.0	2.0	2.0	1.9
65	1.9	1.9	1.9	1.8	1.8
70	1.8	1.8	1.8	1.7	1.7
100	1.4	1.3	1.3	1.3	1.3
140	1.0	1.0	1.0	1.0	1.0

Assumptions: 10 year asset life, 50% tax rate, 20% investment tax credit.

Simple Payback defined as first year's net savings ÷ total investment.



Now, of course, there is one fact of life that we have ignored to this point and that is that most heat pump applications require heat removal at a temperature lower than the source and delivery at a temperature higher than the sink due to heat transfer area economic considerations. A section later in this report persues the economics. Suffice it to say at this point that an optimal design would probably only add 10°F to the combined $T_\beta - T_\alpha$. Revising the COP equation from before to reflect these optimums yields:

$$COP \equiv .7 \frac{460 + T_\beta}{10 + T_\beta - T_\alpha}$$

Delivering one million Btu to the heat user requires $\frac{10^6 \text{ Btu}}{COP}$ in the heat pump plus $\frac{COP - 1}{COP} \times 10^6$ Btu from the heat source. Therefore the energy savings per million Btu through heat pumping is represented by the expression:

$$\text{Savings (per } 10^6 \text{ Btu)} = \beta - \frac{COP-1}{COP}\alpha + \frac{\gamma}{COP}$$

$$= \beta - \frac{\alpha COP - \alpha + \gamma}{COP} = \text{Value} - \text{Cost}$$

Example: For a typical situation the heat source energy could be free or even negative (as in a refrigeration heat load) but for this example it will be assumed at $1/MM Btu for the 200°F sources. Energy delivered to the heat user at say 250°F is valued at $3/MM Btu. Let's also assume that the heat pump has an electric drive and local electric rates are 3¢/kWh

$$COP \equiv .7 \frac{710}{10+250-200} = 8.28$$

γ = Electricity Cost per million Btu

= .03 $/kW x 293 kW = $8.79

$$\text{Savings Per } 10^6 \text{ Btu Energy Delivered} = \$3.00 - \frac{8.28-1.00+8.79}{8.28} = \$1.06$$

or about a 35% reduction in the cost of energy delivered to the heat user.

WHAT CURRENT ECONOMICS INDICATES ABOUT HEAT EXCHANGERS

The operating costs for many processes are becoming increasingly energy intensive. Because of this, processes are being specified with more and more heat exchange equipment and that equipment is being specified with greater surface area than ever before. The following simplified analysis will demonstrate one reasons why this is true.

Assume that one million Btus are delivered in a vapor recompression heat pump. The question to be answered is, "What is the most economic surface area to specify?" Table 3 has been constructed to examine this question. The first column parametrically varies from 2 to 10°F across the exchanger dictating the surface area and marginal surface area depreciation expense as shown in the next two columns. The next three columns indicate the marginal horsepower-related costs. The last three columns show the total operating costs as electricity varies between 3 and 4¢/kWh. Notice that the minimum operating costs are produced with 4 or 5°F temperature differences. These are due to the large effect of the relative cost of electricity compared to the cost of heat exchange surface area.

TABLE 3

ANNUALIZED OPERATING COST PER MILLION BTU DELIVERED IN THE HEAT PUMP

ΔT (°F)	Surface[1] (Sq. ft.)	Surface[2] Cost ($)	Typical HP Required	HP Related[3] Costs ($)	Electric[4] Costs ($)	Total Cost ($) @ 4¢/kWh	Total Cost ($) @ 3.5¢/kWh	Total Cost ($) @ 3.0¢/kWh
2	4000	2000	21.6	270	5154	7424	6780	7136
3	2667	1334	22.4	280	5345	6959	6291	5623
4	2000	1000	23.2	290	5536	6826*	6134	5442
5	1600	800	24.0	300	5727	6827	6111*	5395*
6	1333	667	24.8	310	5918	6895	6155	5416
7	1143	572	25.6	320	6109	7001	6237	6143
8	1000	500	26.4	330	6300	7130	6343	5555
9	889	445	27.2	340	6491	7276	6465	5653
10	800	400	28.0	350	6681	7431	6596	5761

Notes:
1. Assuming an overall heat transfer coefficient of 125 Btu/hr-sq.ft.
2. Assuming straight line depreciation (10 year life), cost = $5 x surface area
3. Assuming straight line depreciation (10 year life), cost = $125 x hp required
4. Assuming 4¢/kWh and 8000 hrs/yr operation

COMMERCIALLY AVAILABLE EQUIPMENT

For the majority of heat pump applications, the predominant components are compressors, mechanical drives, heat exchange equipment, piping and controls. Typically, the user will assume responsibility for the process tie-in and may even directly purchase the components and do the entire installation. The large heat pump applications (pumping more than 100,000 acfm of vapors) are often the domain of the A&E firms due to the size and expense of the equipment.

An estimate of the cost of an installed heat pump can be made by using the following guidelines. The compressor has two basic parameters that benchmark its cost: flow and horsepower. Basically, the flow is dictated by the amount of heat pumped while the horsepower is also a function of the pressure ratio required to pump the heat. Again the useful formula for COP can give us an easy handle on that:

$$\text{Energy of Work (hp)} = \left(\frac{\text{Energy Pumped (Btu/hr)}}{1782}\right)\left(\frac{10+T_\beta-T_\alpha}{460+T_\beta}\right)$$

While actual equipment should be selected based upon manufacturers specifications such as in Illustration 2, the cost of the compressor including controls and lube system may be approximated in 1980 dollars by the expression:

$$\text{Compressor Cost (\$)} = 2000 \times (\text{flow})^{.5} + 30 \times \text{hp}$$

where the flow is expressed in entering acfm of vapor. Corrosive resistant materials could cost up to 1½ times this amount.

Heat exchangers are estimated at about $5 per square foot of required surface with typical shell costs at $25,000. Stainless generally doubles these costs. The other costs would be that of installation and process tie-in. These costs are highly variable and are difficult to estimate in general. Our experience has indicated that they are about as large as the equipment in question. We will continue the analysis on that basis, i.e., that the installed cost is twice the cost of the equipment.

A DISTILLATION TOWER EXAMPLE:

Illustration 3 is a schematic of a distillation tower with an overhead condenser (shown dotted) and a reboiler modified to use the overhead vapors to reboil the bottoms. These vapors are compressed to the pressure corresponding to about 5-10°F above the bottoms so that the latent heat may be transferred. Frequently an additional trim cooler is required since the heat duty of the overhead condenser is often greater than the reboiler heat duty. For this example, we will look at transferring 40×10^6 Btu from the overhead condenser at 170°F to the reboiler at 250°F. The overhead vapors in this case have a specific volume of 2.5 cu-ft/lb, a latent heat of 800 Btu/lb, and are flowing at 50,000 lb/hr. Energy used in heating the reboiler is valued at $3 per million Btus, the cost of providing overhead cooling is $.25 per million Btus and the local electric rate is 3¢/kWh. The column typically runs for 8000 hours per year.

$$\text{Heat Pump Work (hp)} = \frac{40\times10^6}{1782}\left(\frac{10+250-170}{460+250}\right)$$

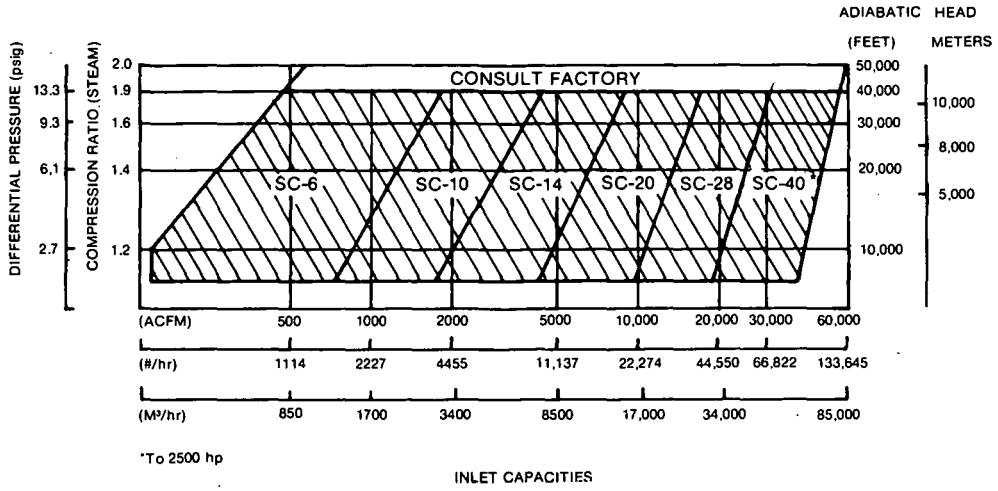
$$= 2845 \text{ hp}$$

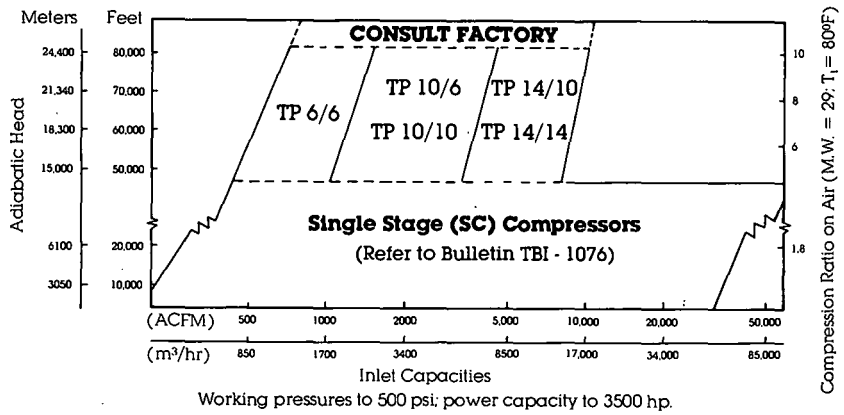
$$\text{Vapor Flow (acfm)} = 50{,}000 \text{ (lb/hr)} \times 2.5 \text{ (cuft/lb)} \div 60\text{(min/hr)}$$

$$= 2083 \text{ acfm}$$

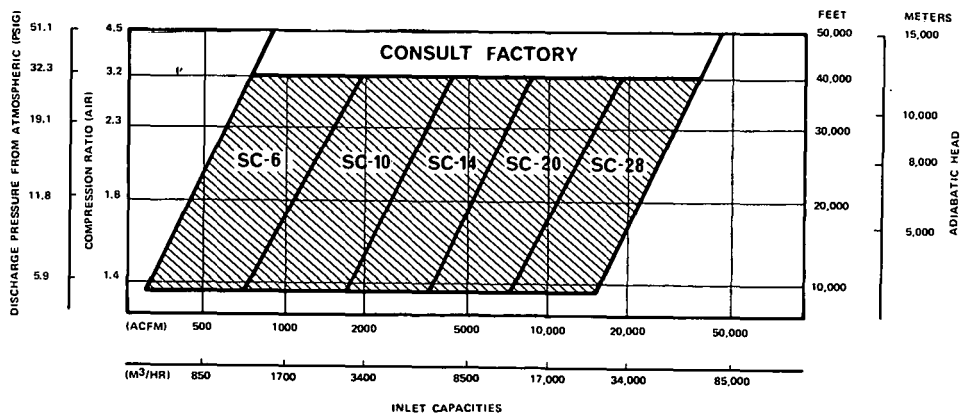
ILLUSTRATION 2

SINGLE- & 2-STAGE (TP) CENTRIFUGAL COMPRESSOR SIZING CHARTS





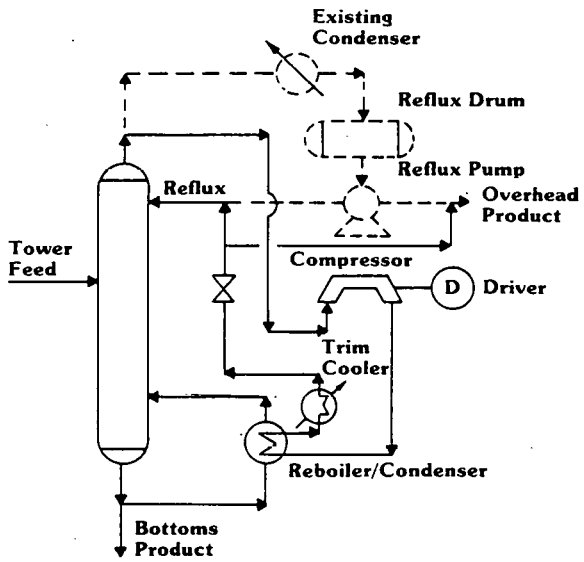
Working pressures to 500 psi; power capacity to 3500 hp.



Note: Data supplied by Turbonetics, a division of Mechanical Technology Incorporated

ILLUSTRATION 3

DISTILLATION TOWER HEAT PUMP
USING OVERHEAD VAPOR COMPRESSION



Compressor Cost ($) = 2000 x $(2083)^{.5}$ + 30 x 2845

= $176,600

Heat Exchanger Area (assuming a 5°F ΔT and U=125)

$$= \frac{40 \times 10^6}{(125)(5)} = 64{,}000 \text{ sqft}$$

Heat Exchanger Cost ($) = 64,000x5 ($/sqft)+25,000

= $345,000

Total Equipment Cost ($) = 176,600 + 345,000

= $521,600

Probable Installed Cost ($) = $1,050,000

Savings are calculated as follows:

$$COP \cong .7 \frac{460+250}{10+250-170} = 5.52$$

γ = Electricity cost per million Btu

= .03 $/kW-x 293 kW = $8.79

Savings per million Btu delivered

$$= \$3.00 - \frac{(-.25)(5.52)+.25+8.79}{5.52}$$

= $1.61 per million Btus

The first year savings are:	$515,200
- Operating costs (assuming 7% of cap cost) =	$73,500
Net first year savings	$441,700

$$\text{Simple payback} = \frac{\$\ 441{,}700}{\$1{,}050{,}000} = 42\%$$

which, using Table 2, will yield about a 3-year after tax payback.

AN EVALUATION OF INDUSTRIAL HEAT PUMPS FOR EFFECTIVE LOW-TEMPERATURE HEAT UTILIZATION

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Mechanical Technology Incorporated
Latham, N.Y.

The implementation of industrial heat pumps utilizing waste water from various industrial processes for the production of process steam is presented as a viable economic alternative to a conventional fossil-fired boiler and as an effective fuel conservation measure. With advanced, high-performance industrial turbocompressors capable of delivering 45,000 feet of head at 60,000 acfm, waste stream temperatures as low as 140°F can be used economically.

Three heat pump systems are described and presented schematically, differing primarily in the heat exchange strategy from the effluent to the heat pump power fluid. Detailed studies were made of two open-type Rankine cycle systems using water vapor as both the heat pump and process fluid.

The heat pump capital cost, maintenance and electric power costs are calculated through the year 2000 to determine the amortized cost of the process steam and are compared with conventional fossil-fuel-generated steam costs. Heat pump capacities range from 10,000 lb/hr to 250,000 lb/hr of process steam. System variables such as the waste stream temperature, process temperature, heat exchanger and approach ΔT are evaluated parametrically.

The salient features of the vapor turbocompressor, the heat pump's major component, are described. The high-performance turbocompressor is capable of head capacities of 45,000 feet at 80% isentropic efficiency, using a centrifugal impeller driven through a geared speed increaser. Tip speeds and rotational speeds up to 1500 ft/sec and 52,000 rpm, respectively, are characteristic of present-day, high-performance compressors for industrial process applications.

SUMMARY

The application of open-type Rankine cycle heat pumps for industrial process steam generation using effluent streams as low as 140°F is already competitive with coal-fired steam. Amortization of the capital costs added to the annual operating costs results in a 1981 energy price of about $3-4 per million Btu's depending on the plant size and source temperature. However, in each succeeding year, the heat pump becomes more attractive, a consequence of its 50% higher coefficient of performance (COP) (1.30 versus 0.85)* and corresponding lower annual fuel costs. By the year 2000, heat-pump-generated steam is estimated to be anywhere from 16% to 41% cheaper than coal steam.

The Open-Open™** Rankine heat pump uses its unique open cycle features together with an efficient, high head capacity vapor compressor train to provide economic attractiveness. As shown in Figure 1, the Open-Open™ heat pump does not require indirect heat

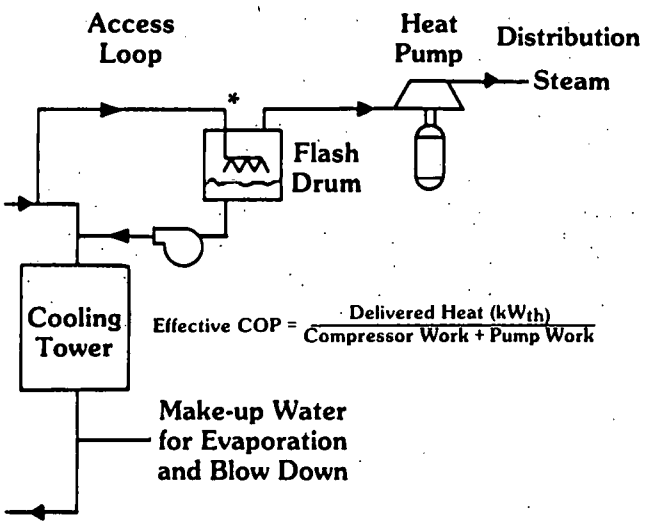


Figure 1 Schematic for Open-Open™ Heat Pump

*The heat pump COP of 1.30 assumes an electric power conversion efficiency of 0.33.

**Open-Open™ as used here describes a heat pump which is open on both sides, i.e., no evaporator nor condensor is required, thus the term Open-Open™.

exchange equipment, and, thereby, reduces capital costs and operating costs; the latter is a result of eliminating the approach ΔT normally required to effect the heat exchange to and from the heat pump fluid. As a limiting factor, however, the Open-Open™ configuration can only be used in conjunction with relatively uncontaminated effluent streams, lest the carry-over of the contaminants to the final process.

For a base-line case, 29,000 lb/hr of 260°F, 20-psig process steam was generated using 150°F effluent water resulting in a COP of 3.86. The total installed cost, in 1980 dollars, was estimated to be $2.35 million. By amortizing these capital costs and using fuel costs (electricity) reflecting the 3.86 COP, the 1981 cost of energy was calculated at $3.18 per million Btu's. A one-year construction period was assumed. This escalates to $9.90 per million Btu's by the year 2000 assuming a 6% general inflation rate. A 10% rate results in a cost of $19.60 per million Btu's. See Figure 2.

A new coal-fired boiler of comparable size is estimated to cost about $2.7 million, including the automated feed handling and stack gas clean-up equipment. Using an 85% conversion efficiency (COP = 0.85), the 1981 amortized cost of steam is $4.50 per million Btu's and escalates to $13.90 by the year 2000, assuming 6% inflation. A comparison of the heat pump versus coal boiler for 11,000 lb/hr to 300,000 lb/hr is shown in Figure 3.

Distillate fuels are no longer competitive. At $0.90/gallon in 1980, the amortized cost of oil-fired steam starts at $7.00 per million Btu's in 1981 and escalates to $28 per million Btu's by the year 2000, assuming 6% inflation. At 10% inflation oil-fired steam is estimated to cost $56 per million Btu's. See Figure 4.

INTRODUCTION

It is estimated that approximately 20% of the heat rejected by industrial processes within the United States is at a temperature below 200°F. Utilization of this rejected heat is severely limited by its lower temperature and by the logistics of the effluent streams. These streams are normally located at remote industrial sites where direct utilization such as district heating, greenhouse heating, catfish farming, etc., are not economical.

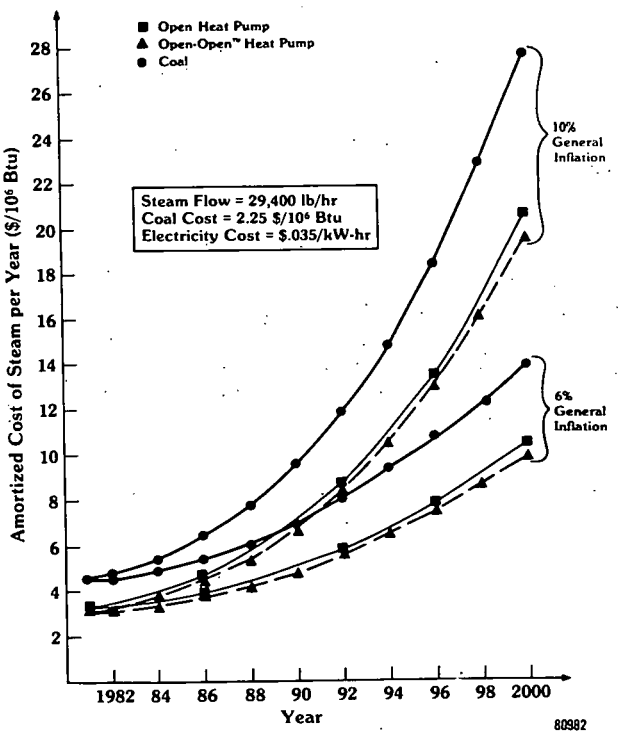


Figure 2 Amortized Cost of Steam Per Year Coal Boiler Versus Open Heat Pump

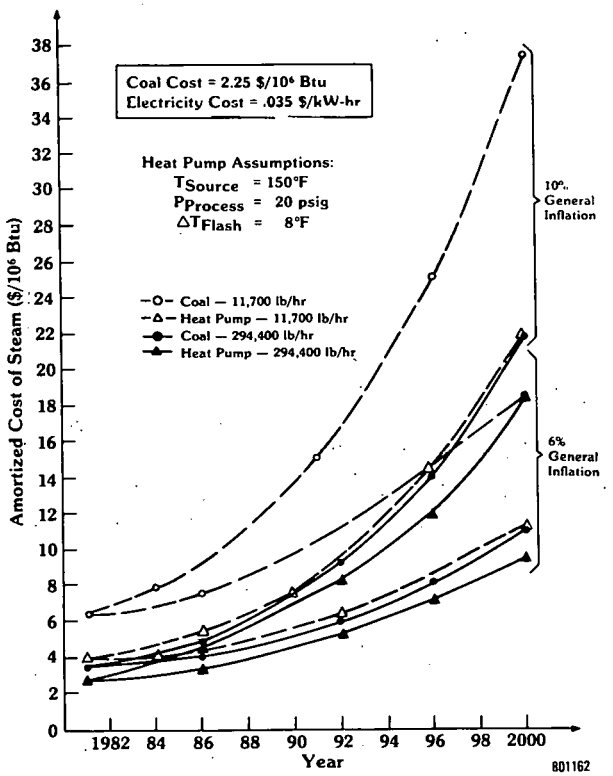


Figure 3 Amortized Cost of Steam Per Year Using Coal Boiler and Open-Open™ Heat Pump

Based on a study [1]* evaluating the potential uses for large quantities of 140-150°F water, heat pumping was selected as an attractive near-term approach. However, electric power generation did not appear as economically attractive.

Three heat pump configurations were examined in the study: a conventional closed-loop organic Rankine cycle and two open-type Rankine cycles. One open type required a kettle reboiler heat exchanger, while the other used waste water directly in a flash evaporation process.

The conventional, closed-loop heat pump operates in a Rankine or refrigeration cycle bounded by two constant temperature lines (isotherms) and a compression and expansion process. The components of the cycle and its thermodynamic description are shown schematically in Figures 5 and 6, respectively. During this cycle, heat supplied in the form of a waste stream effluent (water, vapor, etc.) is used to evaporate (boil) a refrigerant fluid flowing in a closed loop. The fluid is judiciously selected for its thermodynamic properties: boiling point, stability, density, specific heat, etc., for the required temperature range. Selection of a low boiling point fluid (refrigerant) permits evaporation (boiling) to take place at a temperature slightly below that of the waste-stream fluid. The vapor is then compressed to a higher pressure and temperature, whereupon it is condensed to the liquid phase using the process fluid to effect phase transformation. The latent heat given up by the refrigerant during its phase transformation is delivered to the process fluid. The condensing temperature and process fluid flow rate determine the phase of the process fluid, i.e., whether process steam or hot water is to be produced. The hot refrigerant fluid, remaining at an elevated pressure but in a liquid form, is expanded through a throttling valve where its pressure and corresponding temperature are reduced. This reduction in pressure and temperature results in a partial phase transformation as the fluid has expanded to a pressure below the saturation pressure of the refrigerant.

*Numbers in brackets designate references at end of the paper.

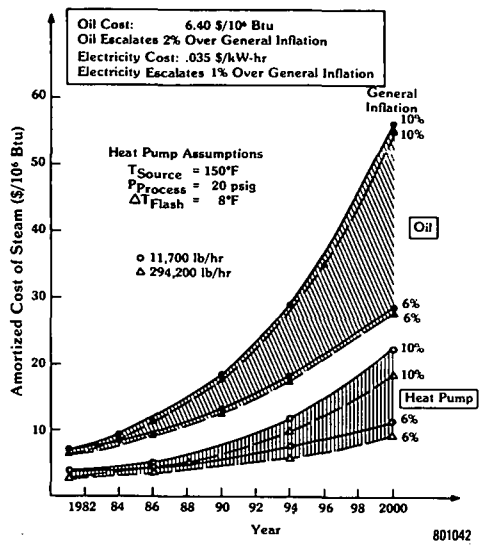


Figure 4 Amortized Cost of Steam

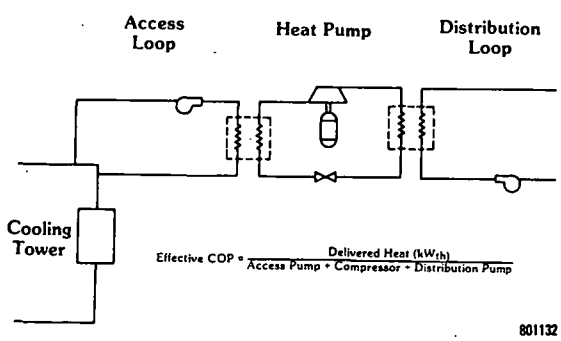


Figure 5 A Conventional Industrial Rankine Cycle Heat Pump

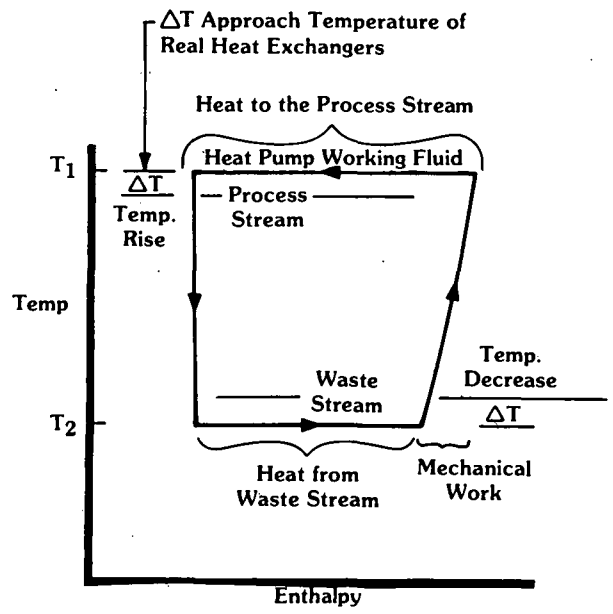


Figure 6 Thermodynamic Description of Closed Rankine Cycle Heat Pump

The two-phase refrigerant mixture then enters the evaporator and the cycle repeats.

Variations of this cycle include one which employs a flash-intercooled, multistage compression strategy designed to take better advantage of the vapor dome and improve the heat pump's performance.

ALTERNATIVE HEAT PUMP CONFIGURATIONS

The closed-loop Rankine or refrigeration cycle just described is the conventional form of most heat pump applications, but there are slight variations that can be implemented which, under particular circumstances, may make another arrangement more desirable. For instance, at source temperatures in excess of 130°F where water undergoes phase change at subatmospheric but workable pressure levels, either one or both of the heat exchangers may be removed and the refrigerant fluid replaced by the process fluid to achieve an open or Open-Open^{TM} loop system. This is shown schematically in Figures 7 and 8. Because these systems are open at one or both ends, the penalty associated with the temperature drop across two heat exchangers in the closed cycle is either halved or eliminated entirely.

The ability to either halve or eliminate the requirement for indirect heat exchangers provides the open-type systems with two inherent advantages: a cost reduction commensurate with the number of heat exchangers eliminated and the performance benefit associated with not having to provide an approach ΔT for the heat exchanger(s). On the other hand, open systems which use water as both the heat pump power fluid and process fluid require larger and more expensive compressor trains owing to the much lower density of water vapor (steam) compared to that of a refrigerant. For example, 15-psig steam has a density of .073 lb/ft^3 while Freon 11 (R-11) has a density of 0.710 lb/ft^3; the latter requires a smaller compressor and fewer stages to pump an equal amount of fluid to the same temperature level. The Open-Open^{TM} system is also limited to applications where the waste wat stream is not contaminated with undesirable pollutants.

Its larger compressor train notwithstanding, the Open-Open^{TM} cycle represents an attractive alternative to the conventional closed cycle both from a thermodynamic and capital cost consideration. As such, it merits further study and is the main subject of this paper. In addition, the incremental change in steam cost resulting from the substitution of a shell and tube heat exchanger for the flash evaporator tank is discussed. The substitution is made necessary by the planned utilization of contaminated waste streams where the carryover of undissolved solids through a flash evaporation process is deemed unacceptable.

Open-Open ^{TM} Cycle

The Open-Open^{TM} heat pump is conspicuous by the absence of heat exchangers at both the evaporating and condensing sides of the conventional closed-loop cycle.

On the hot side, the condenser is eliminated by using steam as both the heat pump power fluid and final process fluid, thereby eliminating an expensive component. In addition, eliminating the condenser improves the cycle performance by eliminating a 20°-30°F approach ΔT and the pump normally required on the distribution side of the condenser.

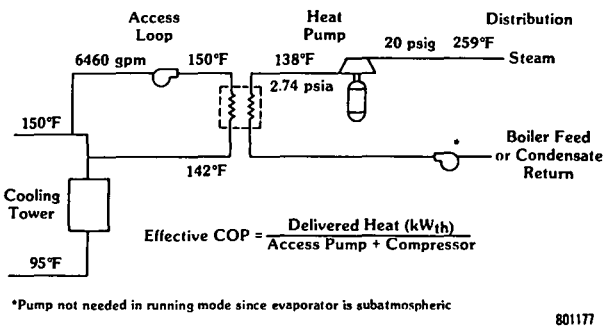


Figure 7 Schematic for Open Heat Pump

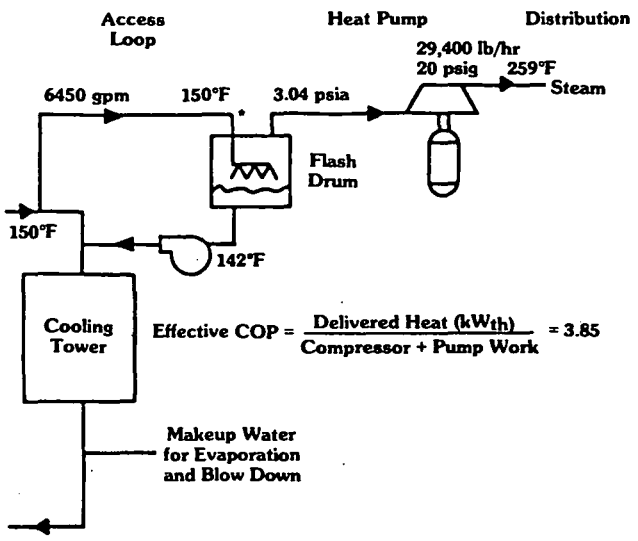


Figure 8 Open-Open^{TM} Rankine Cycle Heat Pump

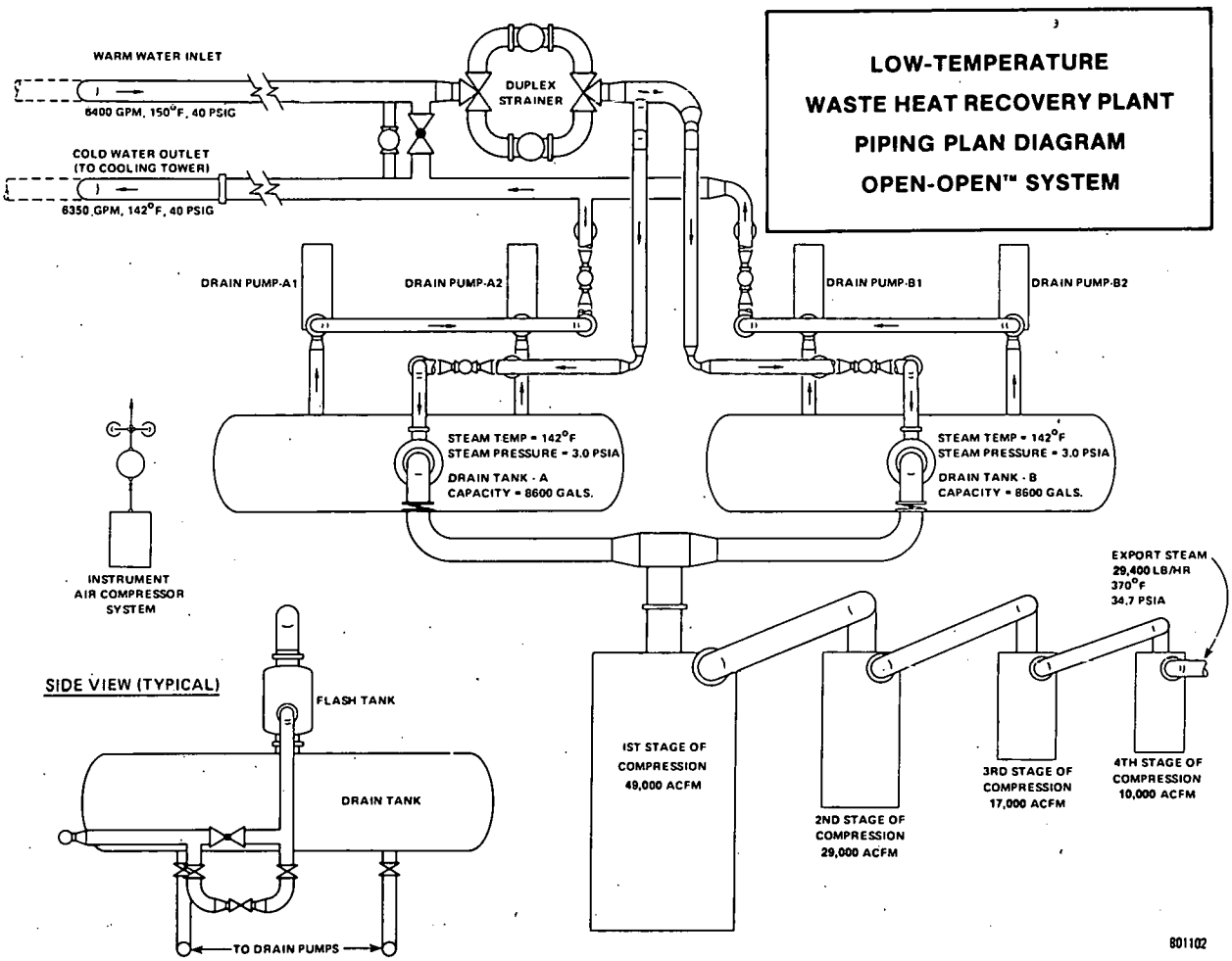


Figure 9 Low Temperature Waste Heat Recovery Plant Piping Plan Diagram Open-Open™ System

On the access side, the tube and shell reboiler used for the evaporator is replaced by a simple, inexpensive flash tank in which the source fluid is flashed to steam (actually subatmospheric water vapor) and then compressed to process temperature and pressure.

As in the case of the distribution side, the replacement of an indirect heat exchanger with a direct flash process improves the heat pump economics in three ways: reduction of hardware cost, access pumping power, and elimination of the approach ΔT. As a result, the final amortized cost of the steam produced is potentially far below that generated using the conventional closed-loop configuration.

While the Open-Open™ cycle has many attractive features which include simplicity, low capital cost, high performance and environmental compatibility, its use is limited to operations where the waste stream is uncontaminated. Any undissolved particles in the waste stream may tend to carry over into the vapor phase during the flash process and would contaminate the compressor train and downstream process.

Operation of the Open-Open™ Cycle. For the baseline case, 6400 gpm of 150°F uncontaminated water is pumped to a 3.5-ft diameter by 5-ft-high flash tank as shown in Figure 9. Here, the sensible heat of the stream is reduced to effect subatmospheric vaporization. The calorimetric heat balance follows:

$$\dot{m}_L \, c_p \, \Delta T_L = \dot{m}_v \, H_{fg} \qquad (1)$$

where: $\dot{m}_L$ = liquid mass flow (lb/hr)
c_p = liquid specific heat (=1 for water)
ΔT = temperature drop
$\dot{m}_v$ = vapor mass flow (lb/hr)
H_{fg} = latent heat of vaporization

Normally, the optimal ΔT_L at these temperatures is about 10°F which then yields a ratio of $H_{fg}/\Delta T_L \sim$ 100 and, correspondingly, indicates that only one part of vapor is generated for every 100 parts of liquid pumped through the flash tank. The 99% of the stream remaining as liquid falls to the drain tank at 142°F and then is pumped back to the cooling tower. Two sets of flash tanks, drain tanks, and pumps are

shown as a redundant measure. Each set of tanks is sized to provide 80% of the vapor flow; 80% is the minimum allowable flow through the compressors without using variable inlet geometry.

With the tank pressure set at 3.04 psia by the compressor suction and the corresponding flash temperature set at 142°F, 25,000 lb/hr of dry saturated vapor is produced. The 142°F flash tank temperature (8°ΔT) was set by optimizing the operating cost of the heat pump as shown in Figure 10. Changing the flash ΔT affects two parameters simultaneously: the liquid side pumping power and the vapor compressor work. At ΔT < 8°F, the ratio of liquid to vapor flow increases. This increases the pumping power more than the overall reduction in vapor compressor work that results from a higher inlet temperature and pressure. At ΔT greater than 8°F, the opposite is true. However, when this occurs, the operating costs escalate at a lower rate than when the ΔT is set lower than 8°F. This suggests that the flash ΔT be biased toward the high side, i.e., ΔT = 8-10°F is preferred over ΔT = 6-8°F.

This vapor is then compressed through four stages using a train of high-performance, high through-flow turbocompressors to produce 29,400 lb/hr of 20 psig dry saturated steam to process. The condensate returning from process is reinjected into the flash tank, decreasing the pumping power by 10%. Because

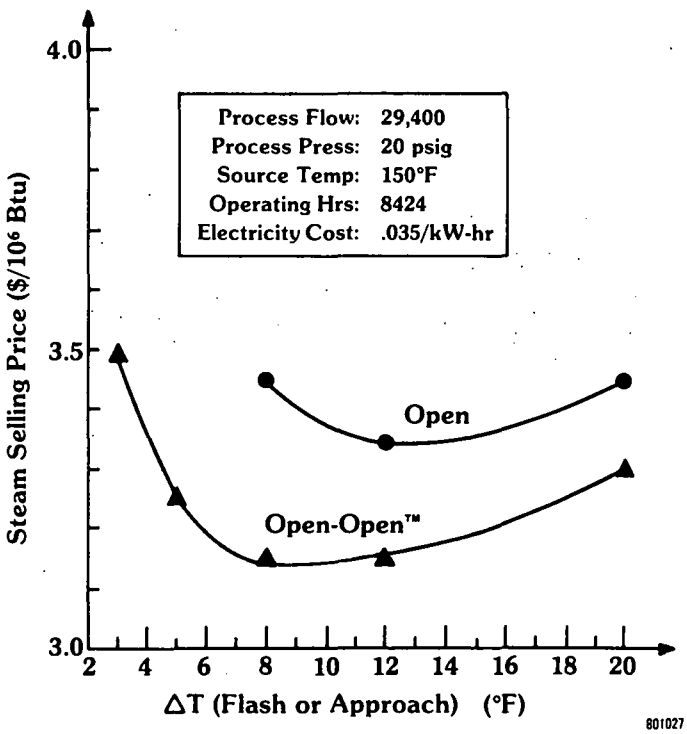


Figure 10 Steam Price Versus Flash Tank ΔT

the compressors play such a vital role in the heat pump cycle, they are discussed in detail in later paragraphs. The thermodynamic representation of the compression process is shown in Figure 11 and the schematic representation of the compressor train is shown in Figure 12.

Using these high-capacity compressors, pressure ratios of about 2 to 1 are achievable in a single stage. These ratios correspond to an isentropic enthalpy rise of approximately 50 Btu/lb (40,000 ft lb_f/lb_m). To maximize performance, the superheat is removed after each stage by injecting atomized water in the desuperheating pipes that separate each compressor. This results in approximately 10% less compressor work as a consequence of the constant pressure lines that diverge as they move away from the saturation line, particularly at the lower pressures where this cycle operates. In other words, for a given pressure ratio, the least amount of work (enthalpy rise) is expended by compressing as close to the saturation line as possible. An example is shown in Table 1. The amount of coolant required for desuperheating represents about 4 to 5% of the vapor flow per stage, and, as a result, there is 4400 lb/hr more steam leaving the heat pump than entering (29,400 lb/hr versus 25,000 lb/hr).

Performance. Overall, the 29,400 lb/hr of process steam is produced at a COP of 3.86. This requires 2100 kW_e of electric power; 1943 kW_e for the compressor drivers, and 157 kW_e for pumping the liquid back to the cooling tower. Amortizing the $2.35 million capital costs in conjunction with the annual operating costs results in a 1981 steam price of $3.18 per million Btu's. At this price the heat pump produces steam for 30% at less than the $4.50 selling price of coal-fired steam. This suggests that the attractive range of the heat pump can be extended to lower source temperatures and/or higher process pressure before reaching the same $4.50 coal-fired steam price. This is shown in Figure 13 where the heat pump's COP, and corresponding steam price, is plotted against the source temperature and process pressure. The heat pump is considered attractive when the steam price is below that of the coal-fired steam, and termed unattractive when the opposite is true.

Effect of Heat Pump Size. The price of steam is presented in Figure 14 for heat pump sizes ranging from 10,000 to 300,000 lb/hr. Interestingly, the costs do not suggest any economy of scale beyond 30,000 lb/hr, both in terms of installed costs and

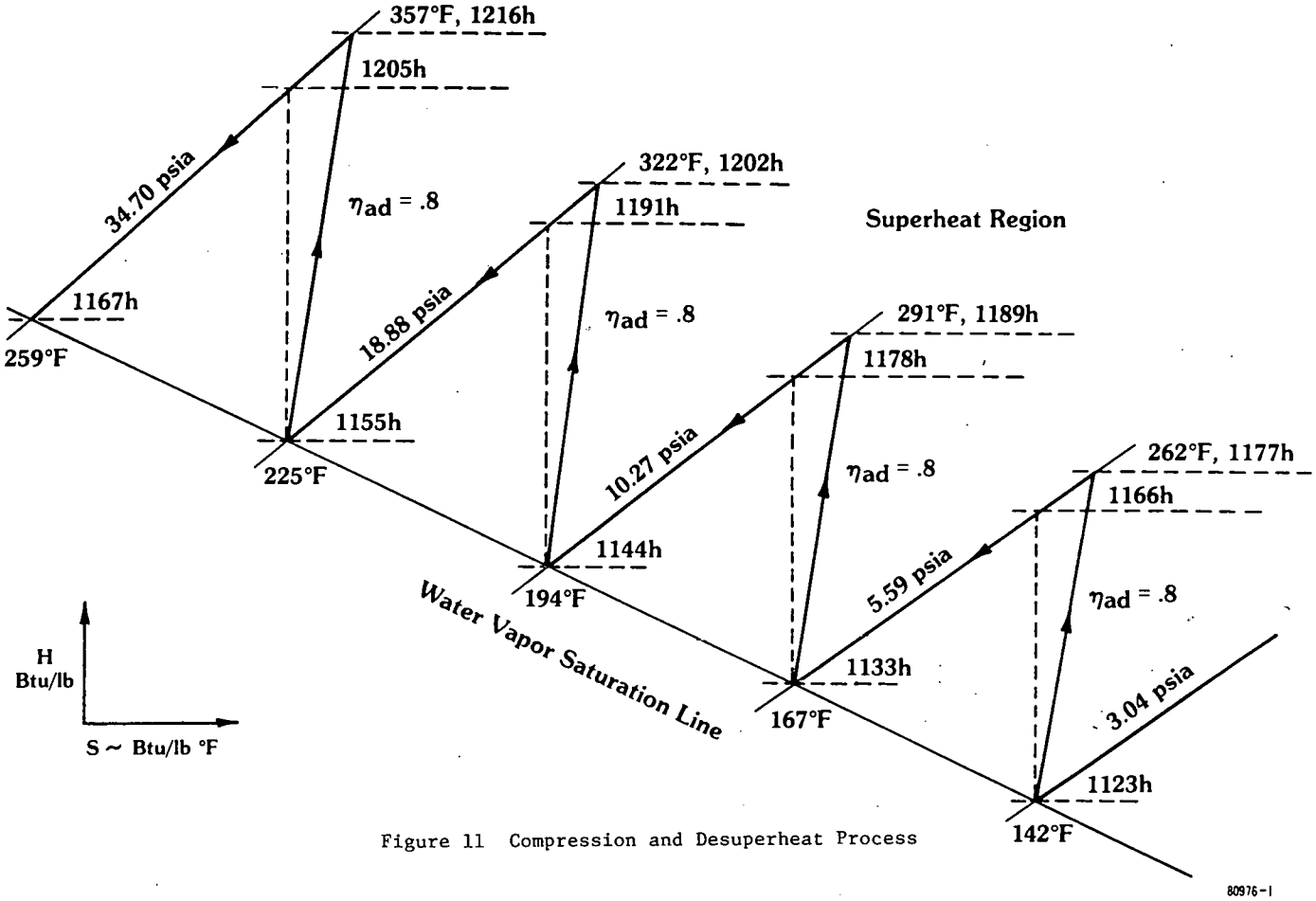
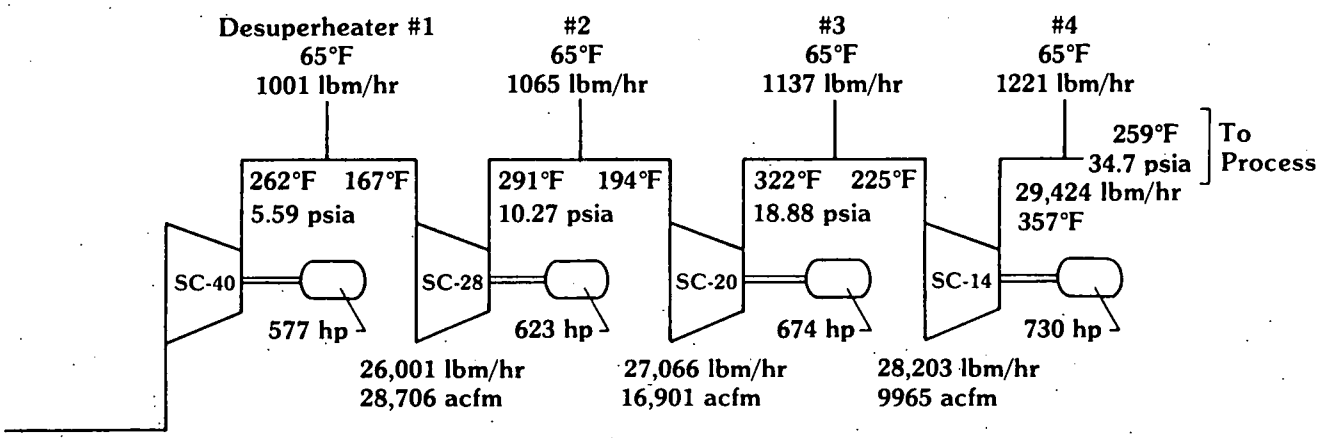


Figure 11 Compression and Desuperheat Process



Power Requirements

$\dot{M}_t$ lb/hr	Δhg (Btu/lb)	(aero + mech) hp
25,000	54.1	577
26,001	56.2	623
27,066	58.4	674
28,203	60.7	730
Process Total 29,424		2604 (1943 kW)

801333-1

Figure 12 Compressor Drive for 29,424 lb/hr, 20 psig Open-Open™ Heat Pump

Table 1
Effect of DeSuperheating During Vapor Compression

With Desuperheaters

Stage No.	T_{sat} °F	P_{sat} psia	M_t lb/hr	M_{ds} lb/hr	Δhg Btu/lb	$(M_t \Delta hg)/3413$ kW
1	142	3.04	25,000	1001	54.1	396.5
2	167	5.59	26,001	1065	56.2	428.1
3	194	10.27	27,066	1137	58.4	463.1
4	225	18.88	28,203	1221	60.7	501.5
To Process	259	34.70	29,424			1789.2

Aerodynamic Compressor Work = 1789.2 kW

Without Desuperheaters

Stage No.	T_{sat} °F	P_{sat} psia	M_t lb/hr	M_{ds} lb/hr	hg Btu/lb	$(M_t \Delta hg)/3413$ kW
1	142	3.04	24,516	4908	271.3	1948.8
To Process	259	34.70	29,424			

Aerodynamic Compressor Work = 1948.8

∴Desuperheating Saves: 1948.8 - 1789.2 = 159.6 kW (8.2%)

Where:

M_t = Stage Inlet Mass Flow

M_{ds} = Desuperheat Flow

Δhg = Enthalpy Rise Across Stage (Assuming 80% Adiabatic Stage Efficiency)

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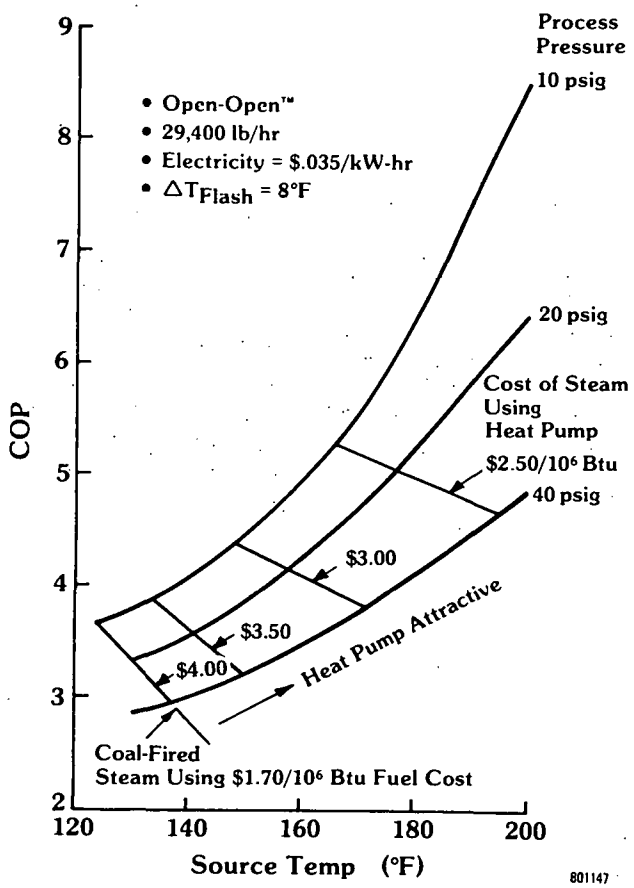


Figure 13 Heat Pump Performance

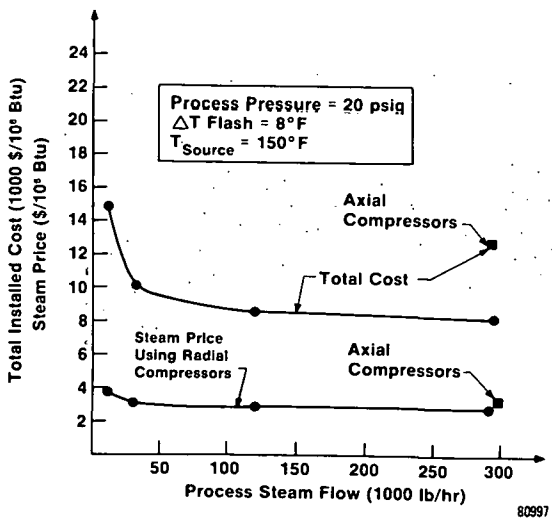


Figure 14 Effect of Open-Open™ Heat Pump Size on Steam Selling Price

amortized costs. This is due to the compressor selection strategy. For plants smaller than 30,000 lb/hr, the compressor train includes machines that are quite smaller than the largest available. On a dollars-per-pound-of-steam basis, these machines are considerably more expensive than the larger ones used throughout the larger plant sizes.

Although it is recognized that a heat pump plant size exists which should dictate the use of axial machinery, the cost of steam was calculated for the 300,000 lb/hr case using axial compressors where possible. The axial compressor trains generated steam at a cost slightly more expensive than the all centrifugal configurations, i.e., $3.20 per million Btu's for the axials versus $2.80 per million Btu's for the centrifugals. While the axial compressors can accommodate almost 10 times as much volume flow, the head rise is so low (7 Btu/lb versus 52 Btu/lb for radials) that it requires almost 8 times as many stages. Consequently, the costs are quite high as attested to by the $9.8 million compressor cost using axials versus $6.0 million for the centrifugal train as required for the 300,000 lb/hr plant.

Open Cycle

Where the effluent stream is contaminated and direct flashing is not feasible, a kettle reboiler is substituted for the flash tank. As shown in Figure 7, evaporation now occurs at 138°F, with a 20°F approach ΔT to keep the heat exchanger surface reasonably low. As a consequence of this lower evaporation temperature (138°F versus 142°F) and corresponding increase in compression power, a COP of 3.73 is achieved which is 3% less than that of the Open-Open™ configuration. This slight reduction in COP, when used in conjunction with a total installed cost of $2.75 million, yields an amortized cost of steam of $3.35 which is $.18 per million Btu's more expensive than the Open-Open™ steam. See Figure 2. The $400,000 difference in capital costs is essentially the result of replacing the flash-tank/drain-tank combination in the Open-Open™ cycle with a kettle reboiler.

Kettle Reboiler. Considerable effort was made to find a high-performance heat exchanger recognizing its critical role in the open configuration. Accordingly, reboilers employing the Union Carbide High Flux™ [2] tubing were selected. Although these were about 60% more expensive than conventional heat exchangers, the overall heat transfer coefficient improved five to six fold.

In terms of the trade-off between the heat exchanger capital cost, tube side ΔT, and approach, the amortized cost of steam was used to optimize the heat exchange process. As shown in Figure 10, the minimum cost occurs at an approach ΔT of 12°F. The tube side ΔT was set at 8°F.

Vapor Compressor

The most technology-intense component within the heat pump is the vapor compressor. Other than the built-in thermodynamic constraints of the system, i.e., the temperature and flow rate of the waste stream and, likewise, that required by the process, the compressor exerts the greatest influence on the performance and overall cost of the steam produced. For the heat pump to be most effective the compressor should accommodate large volumes and should exhibit a high head (lift) capacity while maintaining high levels of efficiency. These requirements are most effectively met using a high-speed radial outflow turbocompressor driven through a single, step-up gear set. A cross section of typical Turbonetics high-performance compressor gearbox assembly is shown in Figure 15.

This generic design results in a family of compressors capable of generating 45,000 ft of head (2:1 pressure ratio with steam) at 80% isentropic efficiency with volume flows of up to 60,000 acfm. Consequently, fewer stages are required resulting in lower capital costs, and, combined with the high conversion efficiency, producing the lowest life-cycle steam costs.

The strategy required to achieve these performance capabilities is directly tied to one crucial ingredient: speed.

Speed Versus Efficiency. The turbocompressor's sensitivity to speed is shown in Figure 16. It suggests a compressor design wherein the blade tip speed and rotational speed are selected to yield maximum efficiency. The specific speed algorithm, defined as:

$$Ns = \frac{NQ^{1/2}}{H^{3/4}} \qquad (2)$$

where: N = rotational speed (rpm)
Q = volume flow (cfs)
H = isentropic head (ft)

show the compressor's sensitivity to rotational speed while the head coefficient lines,

$$\phi = \frac{H}{\frac{(\pi DN)^2}{60}/g}, \qquad (3)$$

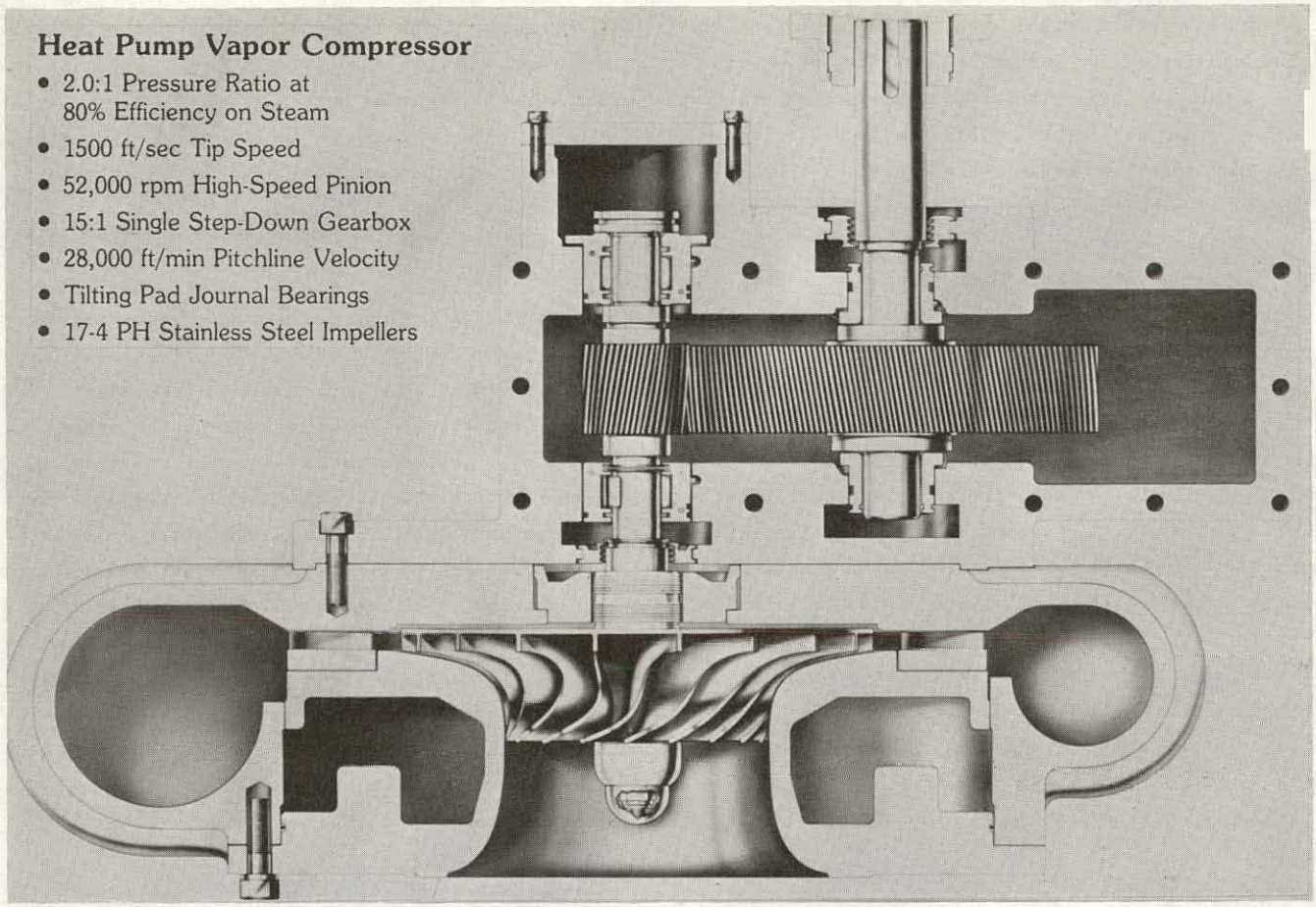


Figure 15 Heat Pump Vapor Compressor

relate the compressor's performance to tip speed, πDN.

The strategy required to achieve high efficiency at high head capacities is to operate at high blade speeds. For low molecular weight fluids, such as water vapor, tip speeds on the order of 1500 ft/sec are required. These tip speeds, in turn, dictate high rotational speeds, particularly for lower volume flows where the blade diameters are small. For example, a 28-inch diameter impeller rotating at 13,000 rpm (1580 ft/sec) can accommodate 32,000 acfm. Reducing the flow to 2000 acfm results in a seven-inch wheel rotating at 52,000 rpm to achieve the same 1580 ft/sec tip speed.

Mechanical Design. The following paragraphs summarize the mechanical design features that permit implementation of the aerodynamic strategy required for high-performance operation.

- High-strength alloys are required for impellers. Typically, impellers are unshrouded precision investment castings of three-dimensional design having backward leaning vanes and a full inducer; see Figure 17. For tip speeds near 1500 ft/sec, 17-4 PH stainless steel is normally used, but for higher speeds Titanium alloys (Ti6Al-4V) are selected.
- Tilting pad journal bearings are required for the high-speed pinion. To avoid potential high-speed instabilities, tilting pad bearings are selected as they are inherently stable. A five-pad centrally pivoted bearing capable of axial and tangential pivoting has provided excellent results [3]. Double-axis pivoting eliminates the possibility of edge loading, and a diametral clearance of 0.0015 in./in. results in attractive levels of bearing stiffness and power loss.
- High-speed overhung pinion designs require comprehensive rotor-dynamics analyses. A lateral dynamic analysis of the high-speed pinion and a torsional anlaysis of the entire compressor/gearbox train ensure stable, vibration-free operation. A rigorous mathmatical model of the rotor system is generated which predicts the rotor behavior within an accuracy of 5% [4]. This precision permits operation of the compressor between the first and second bearing critical speed; this type of operation maintains a comfortable 15% to 20% margin above the first critical.
- Highest quality gears are required for single-step, high-ratio speed increasing. Operation of

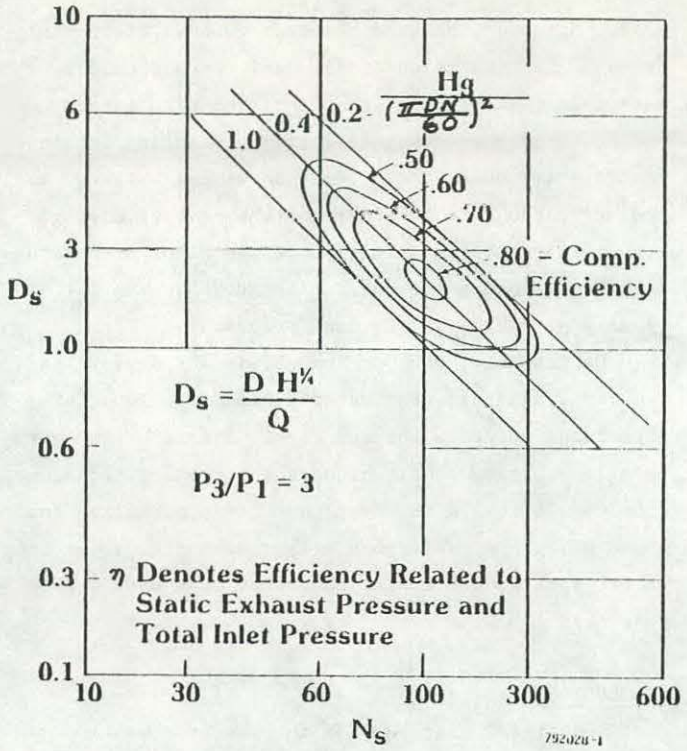


Figure 16 Specific Speed (N_S), Specific Diameter (D_S) Relationship for Centrifugal Compressor

helical gears with high reliability at pitchline velocities in excess of 30,000 ft/min dictates the highest quality tooth accuracy. Accordingly, the AGMA Q13 standard is specified for all gear tooth profiles using case carburized 9310H or nitrited 4140 ground gears. Using the surface endurance fatigue stress as the primary design criterion rather than the tooth bending fatigue stress, the gear will fail by surface wear. This wear will result in increased vibration rather than a fully sheared-off tooth. The gears have a design life of 10 years (87,600 hours).

In an attempt to dispel a common criticism of high-speed turbomachinery (i.e., that it requires high-ratio speed-increasing/decreasing gear sets which are too often troublesome), approximately 400 units of Turbonetics compressors have been manufactured totaling about 4 million hours of operation without one gearbox-induced failure as yet reported.

ENERGY COSTS

In computing the cost of process steam using an industrial heat pump, only incremented costs directly associated with the heat pump were considered. These costs included the compressor and electric motor skid assemblies as quoted by Turbonetics Incorporated together with the heat exchanger, pumps, and balance of plant (BOP) costs specified by Ford, Bacon and Davis

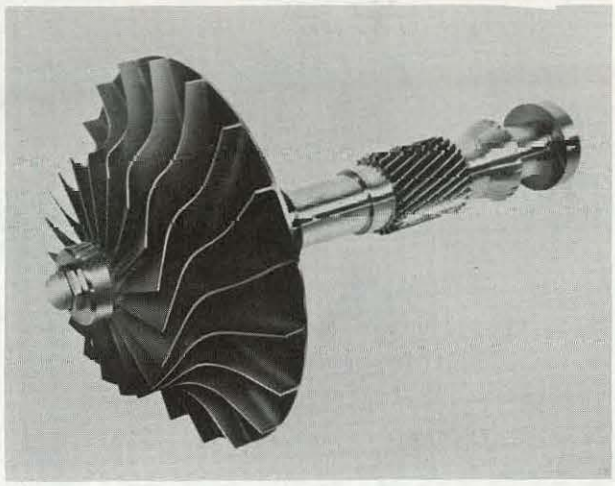


Figure 17 High-Speed Pinion

Utah, Inc., who then used these component costs and estimated the installation costs to provide the total installed cost of the heat pump plant.

The heat pump total installed cost was then amortized to reflect the cost per million Btu of steam produced. The total investment was amortized over a 20-year life, financed with a 10% bond. Utilization of the heat pump is 8424 hours per year including two-weeks shutdown for scheduled maintenance. Operating and maintenance costs are based on 3066 manhours annually at $15.00 per hour inflating 6% annually. Miscellaneous operating costs were taken at 2% of total installed costs. Two inflation rates, 6% and 10%, were used to sensitize the steam costs to inflation. An electric power rate of $0.035/kWh was chosen for the compressor and pumping costs. Its escalation was set at 1% over the general inflation rate. Full heat pump system operation was assumed for 1982.

The preceding financial information was used in a financial model to produce the annual selling price of steam, assuming the heat pump system to be operated by a quasi-governmental thermal utility. This price was determined by calculating the annual cash flow required for the capital and operating costs and dividing it by the total annual quantity of steam delivered.

Heat pump energy costs were compared with fossil-fuel-fired boilers which are based on vendor estimates for oil-fired systems scaled to size. Installation costs for coal- and oil-fired systems were calculated using estimates from Reference [5]. 1980 costs of oil and coal of $6.40 per million Btu and $2.25 per million Btu, respectively, were escalated at 2% over the general inflation rate. This is 1% greater than the

electric power escalation rate.

The after-tax effect of capital and operating cost, including a 15% return on equity, was determined for the internal industrial generation of steam. An investment tax credit of 20% was applied to the heat pump while the coal- and oil-fired plant received a 10% tax credit. The tax credit was reinvested in the plant to yield the same 15% after-tax return on equity. The annual capital and operating cost for a 100% utilized system was determined and evaluated as an after-tax cost per million Btu's. This after-tax cost was adjusted by the marginal tax rate resulting in an equivalent purchase price for the internally generated steam. This equivalent purchase price is directly comparable to the effective selling price of the heat pump steam.

Inflation and Future Energy Cost Scenarios

Obviously, predicting costs of energy twenty years from now is an almost impossible task as costs are directly tied to inflation, foreign oil pricing strategy, and our country's ability to utilize alternate fuels. For example, changing the inflation rate of coal prices from 8% to 12% results in a Year-2000 amortized steam cost of $14 and $28 per million Btu's, respectively, for the 29,000 lb/hr plant size, indicative of the steam cost's strong sensitivity to fuel escalation rates.

Having just suggested the folly in attempting to accurately predict energy costs 20 years from now, the heat pump versus fossil boiler decision should reflect more than the predicted amortized cost of the steam generated. There are two major factors which should be accounted for that are not immediately apparent in the steam cost: ratio of fuel to amortized capital cost, and degree of uncertainty.

In the case of the former, it is this ratio $\left(\frac{\text{fuel costs}}{\text{amortized capital costs}}\right)$ which determines the slope of the steam costs over the amortization period, the steeper slope indicative of a greater quantity of annual fuel costs (lower COP). In other words, a coal boiler starting up in 1981 generating steam selling at $4.50/million Btu's reflects about a 50/50 split between amortization of capital and annual fuel costs. Inasmuch as the capital amortization is constant throughout the period, the major factor responsible for the escalation of the overall cost of steam must be the cost of fuel. See Figure 2. The heat pump, therefore, by virtue of its 50% higher COP than the boiler, becomes less expensive in each succeeding year. Moreover, because the heat pump is electrically driven, the escalation of its fuel costs should be less than that of coal because of the significant number of nuclear and hydro-electric generating stations that are immune to the escalation of coal prices, and secondly, the fact that part of the cost of electricity reflects the amortization of the plant's construction costs, which are not subject to the same inflationary pressures as the coal prices.

Uncertainty, another factor, is why an investor requires, and gets, a greater yield for a long-term note than one for a shorter term. Accordingly, everything else being equal, a capital budgeting decision should tilt toward the heat pump as it minimizes fuel consumption and correspondingly reduces the amount of uncertainty in estimating the steam cost over a 20-year period.

CONCLUSIONS

Industrial heat pumping in open-type Rankine cycles is already less expensive than coal for the production of low-pressure steam using equipment that is available today albeit of high-technological content. In future years, the heat pump's edge over coal-fired steam will continue to improve, primarily due to its higher COP and slower escalating fuel costs, i.e., electricity is expected to escalate at one-half the rate of coal in real dollars.

In general, the open-cycle heat pumps look most attractive at source temperatures in excess of 140°F and for processes requiring no higher than 40-psig steam. Depending on particular circumstances, this range can be extended to sources under 130°F and processes over 50-psig.

Although the open heat pump arrangement is more costly than the Open-Open™ system by virtue of the need to install an indirect heat exchanger, the actual difference in the selling price of the steam produced is quite small: about 6%.

ACKNOWLEDGEMENTS

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A MICRO-COMPUTER-BASED FUEL-OPTIMIZATION SYSTEM UTILIZING IN-SITU MEASUREMENT OF CARBON MONOXIDE

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ABSTRACT

A microcomputer-based control system utilizing a distributed intelligence architecture has been developed to control combustion in hydrocarbon fuel-fired boilers and heaters to significantly reduce fuel usage. The system incorporates a unique flue gas analyzer that mounts directly in the flue or stack to continuously measure carbon monoxide, unburned hydrocarbons, opacity and temperature. The control console interfaces directly with the boiler's existing analog control system to provide precise air:fuel ratio control based on carbon monoxide measurements. Significant decreases in excess air result in reduced fuel usage while meeting steam demand. Actual performance on industrial boilers shows increases in efficiency of from 1% to 3% with substantial fuel savings.

INTRODUCTION

The major economic burden of the eighties will be energy. Costs will continue to increase and uncertain supplies will make forecasting difficult. Fortune magazine [1] estimated that the cost of energy to users now claims 13% of the G.N.P. versus about 9% in 1972, or about $184 billion last year in 1972 dollars versus $108 billion in 1972.

Industry has paid a sizable portion of the energy bill and has become a conscious leader in reducing the energy content of manufactured goods through remarkable progress in energy conservation. Using energy more efficiently is a principal goal of management as conservation is recognized as the only practical answer to the energy situation in the absence of near term alternative energy sources [2].

The real opportunity in the industrial sector is "retrofit" or changes in equipment and the integration of new technology into existing processes to increase the thermal efficiency. Included are industrial boilers and heaters which consume large amounts of hydrocarbon fuels and represent an enormous opportunity for fuel savings through the application of new fuel optimization control techniques and equipment.

One technique in particular is the use of carbon monoxide as the primary control measurement, instead of oxygen, coupled to a feedback supervisory control system to minimize excess air levels in steam generators and heaters. This technique can now be applied easily and inexpensively by using a new microcomputer-based fuel optimization system that utilizes a unique in-situ flue gas analyzer that accurately measures carbon monoxide, opacity and hydrocarbons. This system can be interfaced easily with existing analog controls providing carbon monoxide-based supervisory control with full analog backup. The installed cost of approximately $60,000 can be recovered in less than two years on most boilers and heaters through fuel savings of 1% to 5%.

CARBON MONOXIDE-THE KEY TO INCREASING EFFICIENCY

The Econics 700 Fuel Optimization System uses a highly accurate and sensitive flue gas analyzer with a built-in microcomputer to continuously measure carbon monoxide (CO) using infrared spectroscopy. CO is a direct product of combustion and thus its concentration level in the flue or stack gases directly reflects changes in the combustion conditions.

A plot of CO concentration versus air flow shows the characteristic break point or "knee" that occurs at the minimum air flow or air:fuel ratio required to completely combust the hydrocarbon fuel. CO has been routinely used to locate the minimum air point in the adjustment of operating set points for O_2 analyzers [3]. Current practice (in those facilities so equipped) is to reduce air flow until a predetermined level of CO is reached or until a certain smoke spot number or opacity level is reached. The oxygen level at this minimum air flow is noted and then an operating margin of from 1.5% to 3% O_2 is added to compensate for variations in fuel heat value and atmospheric conditions.

Direct measurement of CO eliminates excess operating margins and errors from air leakage common with O_2 measurement. The reduction in operating margins represents a significant economic opportunity for operators of boilers and heaters through fuel savings resulting from decreased heat losses that accompany lower excess air levels.

INTELLIGENT FLUE GAS ANALYZER

Econics Corporation has developed an in-situ flue gas analyzer that accurately measures carbon monoxide, opacity and hydrocarbons. The design uses a built-in microcomputer and integrated circuitry combined with proprietary mechanical and optical designs. This analyzer is pictured in Figure 1 and shown schematically in Figure 2.

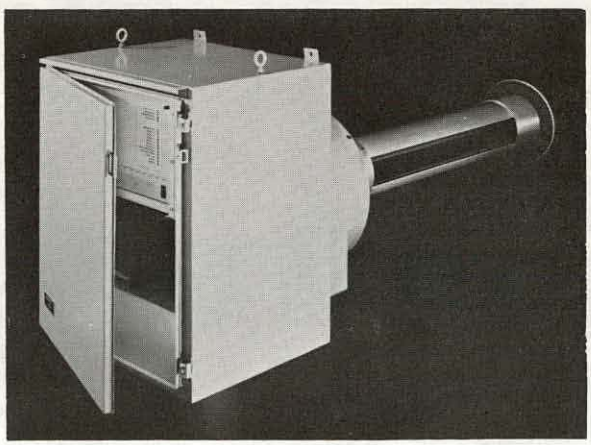


Figure 1
Flue Gas Analyzer

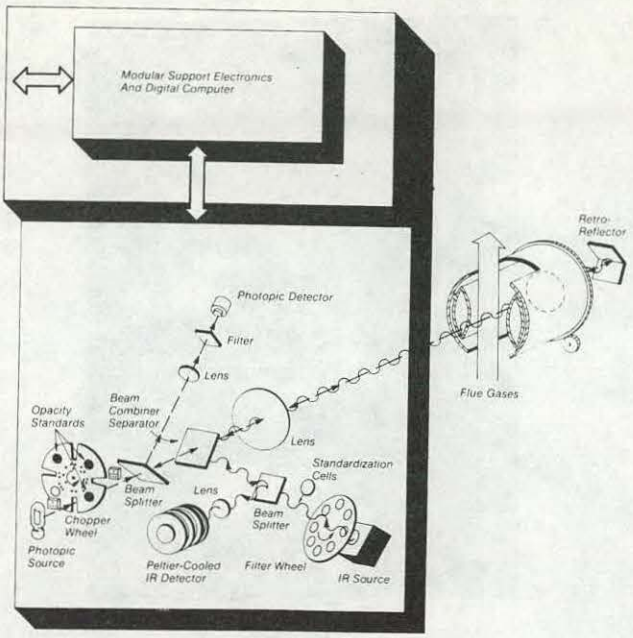


Figure 2
Flue Gas Analyzer Schematic

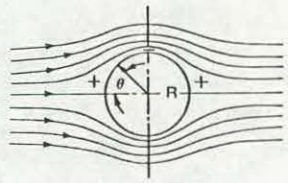
The sensor uses an infrared (IR) absorption spectrometer and a visible photometer to selectively measure the concentrations of carbon monoxide and hydrocarbons and opacity level. Narrow band pass interference filters are used to chop the infrared light into the specific absorption wavelengths for the measured species. The IR pulses are directed through the sapphire window, using a beam combiner/separator to combine the IR beam with the visible beam, across the stack and through a second sapphire window where the radiation is bounced off a retroreflector and back across the stack where the IR and visible beams are then optically separated. The IR beam is focussed onto a thermionic emission cooled detector and the output is fed directly into the 16 bit, 8K word microcomputer via a high speed analog to digital converter.

The built-in computer does all of the signal processing and computational analysis to accurately determine the constituent concentrations and the opacity level.

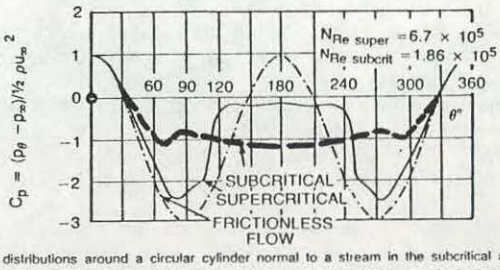
Carbon dioxide and water vapor concentrations are also measured using infrared and the data is used to correct for the absorption interference caused by these constituents in the measurement of CO. We have determined these interference factors as a function of flue gas temperature, also measured, and programmed them into the algorithms stored in read-only memory (ROM). Therefore, as the water and carbon dioxide flue gas fractions change, their interference effects on the CO measurement are automatically compensated for in the calculations.

All in-line analyzers are susceptible to dirt accumulation on the measurement windows, which attenuates radiation causing a systematic error, and to errors caused by aging effects on the source and detector elements. Dirt buildup on the windows is minimized through the use of air showers on the windows, but it cannot be eliminated. A patented purge mechanism that uses the kinetic energy of the flue gases provides a convenient way to periodically check the calibration and to standardize the analyzer. The device takes into account that a hollow cylinder placed in a gas stream develops a differential pressure distribution around the cylinder.

The Econics design takes advantage of this differential pressure distribution shown in Figure 3 to purge the tube and allow for a true zero point measurement. In the open position, the flue gases pass through the tube perpendicular to the measurement beam of the analyzer. Periodically, the computer initiates the 90° rotation of the outer sections of the tube. This forms a cylindrical conformation which is rapidly purged by the kinetic energy of the gas stream. The purged gases are replaced with the fresh air that has been showering the windows.



Frictionless flow about a circular cylinder



Pressure distributions around a circular cylinder normal to a stream in the subcritical and supercritical range of Reynolds numbers and for ideal fluid flow (according to O. Flachsbart, *Reports of the Aerodynamic Versuchanstalt*, Goettingen, Fourth Series, p. 134 (1932)).

Figure 3
Kinetic Energy of Flue Gases
Utilized to Purge Measurement Tube

Figure 4 shows the purging effect on the CO concentration. Note that the purging action accelerates rapidly with an angular rotation of only 30°. On a time basis, a complete purge is accomplished in less than 4 seconds. This purging method does not require tight mechanical seals and is unaffected by soot buildup and thermal distortions.

With the measurement tube filled with fresh air, the shift in the calibration curve due to dirt buildup and source/detector variation is automatically calculated and a correction factor for dirt buildup is stored in the computer memory. A standardization check is made by automatically inserting a sample cell, containing a known mixture of gases, into the infrared beam path in the analyzer.

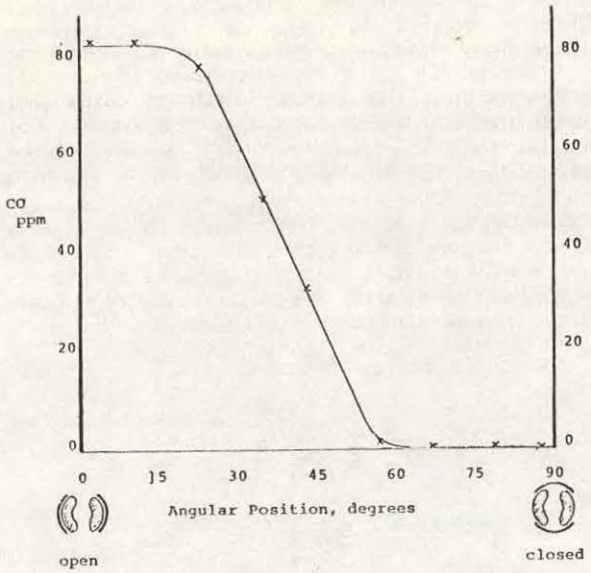


Figure 4
Measurement Tube Purge Cycle



Figure 5
Operator Console

FIBER OPTICS DATA TRANSMISSION

Having achieved a reliable flue gas analysis, the data must be transmitted with full integrity to the operator's console/control center. Traditional electrical transmission requires shielding from electromagnetic interferences (EMI) and radio frequency interferences (RFI). The standard approach is shielded electrical conduit, an expensive but necessary installation method.

Fiber optic transmission obviates the need for shielded conduit and is a practical way to provide highly reliable and inexpensive transmission from the flue gas analyzer to the operators console. The serial data transmission of flue gas composition, opacity, temperature and diagnostic information on flue gas analyzer performance is converted to a serial light pulse train that is transmitted over a thin fiber optic cable. This cable is available with either a standard jacket or an armored version for added resistance to mechanical damage. The cable can be easily strung in existing cable trays.

The flue gas data, reduced to engineering units, is received at the compact (22" x 33") operator's console/control center shown in Figure 5. This console contains a sister microcomputer and support electronics identical to the flue gas analyzer except for the ROM board. Flue gas data together with other process inputs connected through the built-in analog to digitaconvertor are displayed on a 19 inch 7-color interactive video. Control status and alarm limits are also displayed along with a production history frame that shows a 24-hour bar graph of steam production and boiler efficiency.

The operator can easily enter the CO control target and alarm limit levels and turn the CO control and limit controls ON or OFF. The operator's panel is a completely sealed membrane switch array. The pressure-activated panel has no exposed key crevices to accumulate dirt or exposed contact points to corrode. The entire unit can be washed down for easy housekeeping.

DEADTIME-COMPENSATED CONTROL

The Econics 700 System uses a supervisory control approach for maximum control efficiency, safety and cost-effectiveness. With this control approach, the existing analog boiler controls remain intact and continue to function. No costly retrofit of computer-compatible controllers and actuators is required and full analog backup is always available for maximum safety in case of computer failure.

Installation expense is minimal, often less than $2,000 per boiler. In a recent paper mill installation, the Flue Gas Analyzer was installed in less than 6 hours at a cost of less than $1,000 for labor, which was done easily by the customers own personnel. The system was commissioned within a couple of days.

Figure 6 shows the control strategy used by the Econics 700 System. The control is based on a deadtime - compensated algorithm that is tunable on-site through ten-position digital switches located on the computer diagnostic panel board (described below).

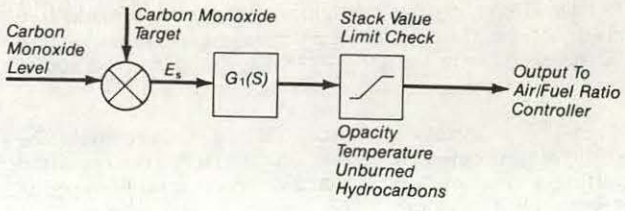


Figure 6
Econics 700 Control

The carbon monoxide measured value is compared to the target value and an error is computed. The control output to the boiler control interface, such as a pulse-to-pneumatic converter linked to an air bias station that adjusts the air:fuel ratio, is calculated based on the time domain response of the boiler. The control algorithm recognizes the time response characteristic of the boiler and the asymmetry of the CO versus air:fuel ratio relationship. The control algorithm also accounts for previous control moves so that process changes that occur before the response to the previous control move is complete can be accurately corrected. A dead band is provided so that trivial control moves are not made.

Prior to making a control move, a limit value check is made on opacity, unburned hydrocarbons, stack temperature and, if the user so desires, oxygen level.

SELF-TEST DIAGNOSTICS SIMPLIFY MAINTENANCE

The Econics 700 System uses designed-in self-test diagnostics to continuously monitor the performance of the electronic, mechanical and optical sub-assemblies in the totally modular design. In the event of a subassembly failure, a LED on the Diagnostic Panel in either the flue gas analyzer or the operators console is illuminated, identifying the failed subassembly. Since most of the subassemblies are in the form of a plug-in printed circuit board, repair is simple and fast.

The diagnostics run continuously and a "picture" of the diagnostic panels can be called up on the video if an alarm message indicates a failure. Spare parts are conveniently stored on site and repairs can be done by the customer's own instrument maintenance personnel.

The simplicity of design with the inherent high reliability and ease of maintenance eliminates the need for costly continuing service contracts that accompany larger energy management systems.

PERFORMANCE RESULTS

Econics has installed systems on boilers ranging in size from 40,000 lbs/hr to 250,000 lbs/hr. Table 1 shows two case histories for gas and oil fired boilers.

TABLE 1.

ECONICS OPERATING RESULTS

Case 1. 35,000 lb./hr. Balanced Draft Boiler

Natural Gas

	$\%O_2$ (Wet)	Excess Air	T °F	Sensible Heat Loss	Nominal Efficiency
Baseline	4.5%	30%	410	10.8%	77%
w/Control	.5%	2.7%	392	8.3%	
	Efficiency Improvement =		3.2%		
	Annualized Fuel Savings =		$37,324		

No.2 Oil

Baseline	9%	78%	520	15.5%	77.4%
w/Control	1.4%	7.5%	478	8.6%	
	Efficiency Improvement =		8.9%		
	Annualized Fuel Savings =		$182,085		

Case 2. 225,000 lb./hr. Gas-Fired Boiler

Natural Gas; 250 days/year operation

	$\%O_2$ (Wet)	Excess Air	T °F	Sensible Heat Loss	Nominal Efficiency
Baseline	3.5%	22%	250	6.2%	82%
w/Control	1.5%	8.5%	245	5.3%	
	Efficiency Improvement =		0.92%		
	Annualized Fuel Savings =		$63,734		

CONCLUSION

Large potential fuel savings can be easily achieved using the Econics 700 microcomputer-based combustion control system. The system interfaces easily and inexpensively with existing analog control systems and provides extremely reliable carbon monoxide-based control that produces fuel savings of 1% to 5% with minimal investment.

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CONTROL-SYSTEM DESIGN FOR EFFECTIVE ENERGY UTILIZATION ... A CASE STUDY

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ABSTRACT

This paper describes the activities and results of a typical plant powerhouse energy management survey. The powerhouse provides electrical energy, steam supply at two different pressure levels, and compressed air for the process plant. The owners had already performed energy loss surveys and implemented maintenance and energy management programs. The activities described include a follow-up survey and a concentration on the improvement of the boiler operations and efficiencies. The Input-Output and Heat Loss methods of determining boiler efficiency, in accordance with ANSI & ASME PTC4.1, are explained. A comparison of the methods, including a sensitivity analysis, shows the effects of measurement inaccuracies on each.

Each boiler is studied and the required measurements identified and described. The importance of flue gas oxygen measurements is described along with the variations in readings obtained using dry or wet basis measurements. The existing operating efficiency of each boiler is determined and the effects of improved controls identified. The considerations for Security, Reliability, Maintainability, and Efficiency Improvement required by any control system are described. A control strategy is selected and hardware chosen to implement the improved boiler and overall steam generation performance.

Focus is shifted from the single boiler problem to the requirements for optimal loading of each boiler to meet total system load requirements. The economics of multiple boiler loading is discussed with the introduction of the Cost Function. This permits direct comparison of boilers even when using different fuels of varying costs. Provisions are included for operator limits of each boiler. These limits are required to permit identification of maximum boiler steaming rates or to provide hot standby (spinning) reserves. Minimum limitations on boiler loading such as burner turn-down are also recognized. In addition, the amount of boiler bias or offset can be limited on a per boiler basis. Lastly, a comparison is made between the powerhouse operation initially, following installation of improved controls, and finally when optimal boiler loading is implemented.

DESCRIPTION OF PLANT

The plant is a refining process which uses energy from a central powerhouse as well as independent fuel consumption. The energy provided by the powerhouse is in the form of 110 psi and 5 psi steam, compressed motive and instrument air supplies, and electricity. The process is such that the powerhouse load remains relatively constant for extended periods of time (days).

The powerhouse consists of ten boilers, seven backpressure turbine driven alternators, various turbine driven pumps and compressors, and two reciprocating compressors. A schematic diagram is shown in Figure 1.

The eight main boilers are rated at 850 psig (saturated) but have varying capacities; boilers 1, 2, and 3 are 175,000 lbs/hr. while the remaining five are 225,000 lbs/hr. The two auxiliary boilers are rated at 110 psig (saturated) but are rarely used.

Seven backpressure-turbine driven alternators provide the approximate 40 megawatts of power to operate the plant. Other turbines provide boiler feedwater pump and air compressor power.

ENERGY LOSS SURVEY

The owners had already performed an Energy Loss Survey and have implemented maintenance and energy management programs. These programs were designed to identify and correct:

1. Steam leaking/venting to the atmosphere
2. Faulty steam traps
3. Uninsulated steam/hot water lines
4. Repeated use of PRV's (pressure reducing valves) for the reduction of steam pressures

A follow-up survey provides verification that the programs are functioning and providing the expected results. In each case, a checklist permits a thorough, objective evaluation of the plant's operation. Many checklists [1], [2], [3] have been published and will not be duplicated here.

In this case, the follow-up survey produced no significant findings and attention was shifted to the next area of energy management - - that of performance measurement and possible improvement in the boiler efficiencies.

EFFICIENCY DETERMINATION

The efficiency of a boiler can be determined by two methods, the input-output method and the heat loss method (ANSI & ASME PTC4.1).

Input-Output Method

$$\text{Efficiency, } \eta = \frac{\text{Heat absorbed by working fluid}}{\text{Heat in fuel + heat credits}} \times 100\% \qquad (1)$$

The input-output method requires an accurate measurement of the quantity and high heating value of the fuel, heat credits, and the heat absorbed by the working fluid or fluids.

Heat Loss Method

$$\text{Efficiency, } \eta = 100\% - \frac{\text{Heat losses}}{\text{Heat in fuel + heat credits}} \times 100\% \qquad (2)$$

The heat loss method requires the determination of losses, heat credits and ultimate analysis and high heating value of the fuel. To establish the capacity at which the losses occur, it is necessary to measure either the input or output as a basis. In

this work, the basis will be the output. The following terms are used:

Output: Heat absorbed by the working fluid or fluids.

Heat Credits: The amounts of heat added to the envelope of the steam generator unit other than the chemical heat in the fuel "as fired". These credits include sensible heat: of the entering air, of the atomizing steam, and of the fuel.

Referring to Figure 2, the efficiency is expressed by two methods of measurements:

Input-Output

$$\eta = \frac{q-q_w}{F+q_o} \times 100\% \qquad (3)$$

Loss Method

(Total loss, $L = q_s + q_x + q_r$)

$$\eta = \left(1 - \frac{L}{F+q_o}\right) \times 100\% \qquad (4)$$

The two equations are equivalent. Furthermore, if the measurements are exact, they should give the same result. Their values can differ only due to measurement inaccuracies.

SENSITIVITY ANALYSIS AND ACCURACY OF RESULTS

The Heat Loss method was pursued for efficiency calculations due to the accuracy of measurements using this method. The Input-Output method requires an accurate measurement of output q, which is not easily obtained. Any error in this measurement will greatly affect the calculation of the efficiency. The sensitivity of efficiency with respect to variations in measurements illustrates this point.

The sensitivity of efficiency with respect to output (denoted by $\int_q^\eta$) is defined as:

$$\int_q^\eta = \frac{\%\text{ change in }\eta}{\%\text{ change in }q} = \frac{\Delta\eta/\eta}{\Delta q/q}$$

$$= (\Delta\eta/\Delta q)\frac{q}{\eta} = \frac{\partial\eta}{\partial q}\frac{q}{\eta} \qquad (5)$$

Substituting from Equation (3) from the input-output method results in:

$$\int_q^\eta = \frac{1}{F+q_o} \quad 100 \quad \frac{q\,(F+q_o)}{(q-q_w)100}$$

$$= \frac{q}{q-q_w} \qquad (6)$$

The sensitivity of efficiency with respect to the losses is:

$$\int_L^\eta = \frac{2\eta}{2L}\frac{L}{\eta} \qquad (7)$$

Substituting from Equation (4) results in:

$$\int_L^\eta = 100\left(-\frac{1}{F+q_o}\right)\frac{L\,(F+q_o)}{100(F+q-L)}$$

$$= \frac{-L}{F+q-L} \qquad (8)$$

A comparison between two sensitivities can be made using the following typical values from field experience:

$$\frac{q_w}{q} = 0.2$$

$$\frac{L}{F} = 0.2$$

$$\frac{q}{F} = 0.8$$

Using the Input-Output Method:

$$\int_q^\eta = \frac{q}{q-.2q} = \frac{1}{0.8} = 1.25 \qquad (9)$$

Using the Loss Method:

$$\int_L^\eta = \frac{-0.2F}{F+0.8F-0.2F} = \frac{-0.2}{1.6} = -0.125 \qquad (10)$$

Which has an absolute value 0.125.

The ratio of these two values is 10. Therefore, if the percentage of error made in measurements is equal, the error in efficiency is much less using the heat loss method. In fact, the percent of error

made in steam flow measurement is greater than that for loss measurements. The errors made in the various measurements and their effects on efficiency are listed in the ASME Power Test Code (ASME PTC 4.1 pg. 26 and 27), see Figure 3.

Root mean square (rms) estimation can be used to determine the amount of error in calculating the efficiency of a boiler. Referring to the ASME table, the error by the loss method is only 0.33% using the rms technique.

For this application, the heat loss method was used to calculate the efficiency because it provides more accurate results.

MEASUREMENTS

The input (or field test) data needed to calculate the efficiency versus steam flow (output) are the following:

Input Data

Fuel Analysis
Fuel heating value
Mass flow of steam output
Enthalpy of steam output
Feedwater temperature
Enthalpy of blowdown steam
Blowdown flow
Flue gas temperature
O_2 in flue gas - wet basis (or excess air)
Excess air at burner
Unburned combustible losses
Mass flow and enthalpy of atomizing steam
Moisture and temperature of entering air
Fuel temperature (before atomizing)
Radiation and convection losses
Unaccountable losses (per manufacturer)

One of the greatest losses of fuel in any combustion process is the energy required to heat excess combustion air, which is lost up the smoke-stack. In order to keep this loss to a minimum, it is necessary to measure excess air. At present, there is no device which can provide excess air directly with any degree of accuracy. Industry practice has been to measure flue gas percent oxygen and obtain excess air from tables or curves.

In order to determine boiler efficiency, the percent excess air must be calculated from the measured oxygen. The accuracy of the oxygen measurement is dependent on the sampling system. The oldest and simplest method of analyzing flue gas is the mechanically-operated, chemical absorbtion device known as the Orsat. In the hands of a skilled operator, using fresh chemicals, the Orsat can provide accurate results, but this is seldom the case. Another disadvantage is that readings are assumed to be on a "dry" basis; that is, the moisture in the flue gas is considered to be completely condensed so that the percent oxygen is expressed as a percent of total flue gas less the moisture. This is not strictly true; thus, Orsat and other water washed sample system analyzers should be corrected for this error which may be as small as 2% or as large as 15%.

Another potential error is the table or curve used for percent oxygen - - percent excess air conversion. Small variations in actual fuel result in negligible errors, but multiple fuel burning requires calculation of the ratio of fuels being fired in order to properly interpolate oxygen-excess air curves.

Equally important is an accurate fuel analysis for the fuel to be used during testing. This must include not only an ultimate analysis, actual heating value per unit (mass or volume) of fuel, but also its moisture content.

Some data in this section taken from a paper by Ragle and Cooper. [4]

IMPROVEMENTS FOR A SINGLE BOILER

As stated previously, the individual boiler performance can be improved by reducing the oxygen (O_2) in the flue gas. Reduction of flue gas O_2 can be accomplished using improved instrumentation and control techniques.

The use of automatic controls with continuous flue gas oxygen recorrection of air flow provides closer (tighter) control of oxygen than can be accomplished by routine operator readjustment of the fuel/air ratio. The tighter control of oxygen when combined with a small reduction in oxygen set point will result in fuel savings. The existing oxygen, along with estimated average values, is tabulated in Figure 4.

The present average value of O_2 in the flue gas is 1.5%. This value can be reduced to 0.8% and be maintained at that value by the new controls and instruments. This proposed O_2 value is attainable as evidenced by Figure 4. However, these low O_2 values cannot be maintained by the current manual readjustment arrangement due to the impracticality of continuous operator surveillance.

Instruments and Controls

Individual boiler operation will be improved by installing electronic controls which will provide the following advantages and features:

1. Tight control of O_2 content in flue gas by continuous automatic readjustment of the fuel/air ratio.
2. Reduced O_2 in flue gases by O_2 trim (cost savings).
3. Efficient operator interaction and power plant operation using new operator interface stations and indicators.
4. Improved plant security, reliability, and maintainability.

The Bailey Conserver™ Systems recommended, meet the user's requirements that the equipment provide improvement over the existing systems with respect t..

1. Security
2. Reliability
3. Maintainability
4. Operating Efficiency

Security of operation is provided by using dedicated panel stations for operator interface. This permits the operator to control the operation mode whether it is computer, automatic, or manual. The system provides direct remote manual operation of each fuel flow, air flow, feedwater flow, and attemperator. In addition, on-line capability is enhanced with the use of a manual bypass provision on each final controlled variable. This provision permits station and controller removal and replacement without interrupting the signal to the drive/valve.

Reliability is improved by providing control systems which can respond to the changing requirements of the process steam flow with minimum upsets to the powerhouse controlled variables (also a security improvement). Reliability is also assured through the use of hardware, field proven in both powerhouse and process plant applications.

Maintainability is improved through the use of easily replaceable plug-in modules, controllers, and stations. Specific module configuration and calibration is accomplished by the use of circuit board "staple" jumpers. Front of module testjacks aid in the troubleshooting and performance evaluation of the control systems. In addition, the availability of spare parts and replacement modules, if needed, assure operation of the system for many years.

Boiler efficiency improvement is attained through the reduction of O_2 to a value consistant with reliable boiler operation. The fact that the boilers

can be operated at low O_2 is verified by chart recordings showing these (and lower) values for short operating periods.

The operator's work load will be reduced due to:

1. All operational data appearing on the console, not on the front and rear of a long panel.
2. All data presented in a grouped format on stations and recorders.
3. All operational actions uniform.
4. No sharing of operator control buttons or displays.

Finally with reduced work load, the operator will better be able to cope with plant disturbances and emergency conditions.

Economics (Cost, Savings, Pay-off)

In spite of the benefits listed for the new electronic controls, economic feasibility will be tested using only the fuel savings expected by operating the boiler at reduced (4.0%) excess air (corresponding to 0.8% O_2) versus the present 7.5% excess air (corresponding to 1.5% O_2).

Calculation of the resulting savings, using a 70% load factor, results in an annual savings of $46,700. If the cost of fuel is expected to rise by 10 percent per year (a conservative value), we can summarize the first five years savings as follows:

Savings per year:	
1st year	$46,733.00
2nd year	$51,407.00
3rd year	$56,547.00
4th year	$62,202.00
5th year	$68,422.00
Equipment Cost (installed)	$81,250.00
Return on Investment (ROI)	47.5%

The same analysis applies to each of the other boilers.

OPTIMAL BOILER LOADING

With the improvement of each individual boiler accomplished, attention is shifted from the single boiler problem to the desirability of optimal loading each boiler to meet the total system load requirements.

Because each boiler has a different efficiency, differing loads can be allocated to each boiler. The efficiencies differ for two reasons: (1) design differences between boilers; (2) different component performance due to aging, malfunctioning etc.

Because of these facts, the efficiencies of each boiler should be measured continuously to be a basis for optimum boiler load allocation. The boiler cost curves (developed) will be updated, and an algorithm for optimal loading will be performed.

Using Figure 2, we can write an energy balance for each boiler as:

$$F+q_w+q_o = q+q_x+q_r+q_s = q + L \qquad (11)$$

where L represents the losses.

Referring to definition of efficiency from equation (3):

$$\eta = \frac{q - q_w}{F + q_o} 100 \qquad (12)$$

The measurements can be made on fuel flow, F, or on output steam flow, q, as follows:

Using equation (11),

$$\eta = \frac{q - q_w}{(q-q_w) + L} 100 = (1 - \frac{L}{(q-q_w) + L})100 \qquad (13)$$

or

$$\eta = \frac{F + q_o - L}{F+q_o} 100 = (1 - \frac{L}{F+q_o})100 \qquad (14)$$

Efficiency values are plotted against output, represented in terms of steam mass flow, m, lbs/hr. If the measurements are made on fuel flow, the energy flow through the fuel, using equation (14), is:

$$F = \frac{(\eta-100)q_o + 100L}{100 - \eta} \qquad (15)$$

In this case, the value of q can be found, for efficiency plotting, from (11) as,

$$q = F + q_w + q_o - L \quad (16)$$

If the measurements are made using output steam flow, the energy flow through the fuel is (from 12),

$$F = \frac{q - q_w}{\eta} \; 100 - q_o \quad (17)$$

Note that feedwater temperature compensation has been included.

COST FUNCTION

The use of the cost function permits direct comparison of different boilers or even the same boiler firing different fuels. Typically, fuel cost is expressed in terms of P, \$/MKB (MKB = 10^6 BTU).

The cost flow into boiler can then be written as,

$$f = PF \quad \$/hr \quad (18)$$

where f is the cost function.

Then, the data for the cost curve of a boiler is a set of values of (f, m).

The pairs of (f_1, m_1) making up (f, m) can be represented by a curve by using least square estimates. A quadratic relation is the simplest relationship suitable for cost function curves. Appendix A provides further development of the least squares estimate of the cost function.

Equation (17) can be used in a modified form if the credits making up q_o have common parameter values.

$$F + q_o = (q - q_w)\; 100/\eta \quad (19)$$

Rewriting the values in terms of mass flow and enthalpy (note feedwater mass flow is (1.00 + .01(b))m where b is blow down in percent), for a 5% blow down, equation (19) becomes:

$$F + q_o = \frac{m(h-1.05h_w)}{\eta} \quad (20)$$

The term q_o refers to heat credits. Since the conditions making up q_o are almost the same for each boiler, it makes no difference whether F or F + q_o i used for optimization.

Letting F' = F + q_o and f' = PF' the cost function f' is written for P = \$4/MKB, as

$$f' = \frac{m(h-1.05h_w)\;\; (100)\;\; (4),}{\eta(10^6)} \; \frac{\$}{hr} \quad (21)$$

$$\text{Letting } K = \frac{(h-1.05h_w)\;\; (100)\;\; (4)}{(10^6)} \quad (22)$$

f' can be written as,

$$f' = K\frac{m}{\eta} \quad (23)$$

The procedure for finding a quadratic function for f' (see Appendix A Eqn. A1) is already described. Normally, the individual boiler loads can be shifted for the same total steam demand and adequate test points can be obtained to describe $f' = am^2 + bm + c$ for an adequate range of loads.

In this case study, the boiler loads did not cover a wide range for the function f' to be valid for a wide range of boiler loads. At the same time, the boiler efficiency curves were close to straight lines and were almost constant for the range of operating loads.

Furthermore, it was noted that enthalpy values of steam and feedwater were almost same for each boiler since they have a common feedwater line, a common steam header, and controlled outlet temperature.

In this case, K defined in Eqn. (22), becomes a constant and f' is written as,

$$f' = K'm \quad (24)$$

where, $K' = (K/\eta)$.

The value of K is calculated for average steam and feedwater temperatures of 1422 Btu/Lb and 320 Btu/Lb respectively, as:

K = 0.4344

The value of K' for the cost function, f' = K'm, is calculated for each boiler and is given in Figure 5.

METHODS OF OPTIMUM LOADING OF BOILER SYSTEM FOR MINIMUM COST

The boilers (except the two small auxiliary boilers) are arranged in parallel and feed a common header. The individual boiler loads will be assigned such that the steam demand is satisfied under the operational constraints, and the cost of steam is minimized. Typical loads and operating restrictions of the boilers are given in Figure 6.

The cost curve developed in Appendix A and described by Equation (A1) is normally used. However, for this study, Equation (24) will be used for optimization since it is valid for this application. The cost curves are described by Figure 7.

From the cost curve the incremental costs (slope of each cost curve) can be calculated. These are shown in Figure 8. Using the incremental cost curves, the boiler loading order is determined. Since minimum and maximum constraints have been established by the operator or by the physical limitations of the equipment (maximum steaming capacity), each boiler must be loaded recognizing those constraints. Figure 9 shows the loading sequence for each boiler at any given total load. As an example, for a total load of 1265 Klbs/hr, a vertical line corresponding to that value intersects the load curves of each boiler giving the optimum load allocation. The restrictions on load levels are also included.

Figure 10 compares the present loading, taken from a typical day's shift log, with optimum loading of the boilers. The efficiencies for each boiler are also included to compare the overall efficiency of the system for the present and optimum loading conditions.

The overall efficiency of the boiler system is calculated as;

$$\eta = \frac{\sum_{i=1}^{7} \eta_i M_i}{\sum_{i=1}^{7} M_i}$$

where η_i, M_i are the efficiencies and loads of each unit respectively.

The improvement in overall efficiency of boiler system, in percent, is:

$$\frac{87.41 - 87.22}{87.22} (100) = 0.22$$

Although this saving is a small number, it will apply to the total boiler system which results in significant savings. The total savings and economic justification will be discussed later.

CONTROLS, INSTRUMENTS & METHOD OF APPLICATION

The operation of the eight boilers will be improved by the preferential loading of the individual boilers as explained above. In order to determine the individual loading, a Bailey computer system is recommended. This function will be in addition to its normal data acquisition and logging functions. The calculations are well within the capacity and timing of the recommended system.

The interface of the Bailey computer and electronic boiler controls will be accomplished through supervisory set point control of the plant 850 psig header pressure set point, the individual boiler bias, and the O_2 set point bias. This will permit operator selection of computer or manual operation. Manual operation can include operator set loadings based on computer printout recommendations. The hardware interface provides for the selection,

with circuit board "staple" jumpers, of one of three possible control modes upon loss of the computer.

1. Maintain last setpoint

   This maintains "status-quo" or the last set level upon computer loss.

2. Predetermined set point

   The set point will slowly ramp to a previously operator set value upon computer loss.

3. Manual

   The operator station will transfer to manual upon computer loss.

In all cases, computer loss is annunciated.

This interface provides for security of operation because the mode of operation upon computer loss is known and understood by the operator.

System reliability is improved because the computer interface is physically located in the boiler control equipment racks not in the computer system. False signals transmitted to the boiler control equipment during a computer outage are ignored.

Maintainability is improved because the interface is a hardware module not a software program. The module can be checked or replaced while the computer or control system is operational.

To summarize, the Bailey computer and control systems were chosen because they are complimentary systems; that is, the addition of the computer increases the power of the boiler controls allowing optimization and data acquisition functions to be performed without compromising the control systems ability to react to plant upsets. Additionally, the operator can gain manual control at any time should he desire to do so.

IMPROVEMENTS FOR THE TURBINE SYSTEM

An increase in overall turbine system efficienc similar to the boiler system, can be achieved to minimize the cost of electricity production.

The turbine efficiency can be calculated from on-line measurements of inlet and outlet conditions. Since the turbines are backpressure units, the steam quality (moisture content) does not enter into the determination of the enthalpy; thus, only pressure and temperature need to be measured. These measurements exist and only need to be connected to the computer for the efficiency and optimization calculations.

The required turbine loading requirements will be printed for operator action to change the individual turbine governor valves.

The method used for turbine efficiency measurement is described in Appendix B. The efficiencies vary slightly with load. However, the differences between the efficiency values of two different turbines were much larger. The examination of the efficiency data (versus load) indicated that the average efficiency versus load of these turbines is almost constant.

Similar to the results of the boiler system optimization, the most efficient turbine-alternators will be loaded to their high load limits and the less efficient turbine-alternator loads will be decreased. Figure 11 gives the observed loadings and optimum loadings of the turbine-alternators along with the efficiency values.

The overall efficiency improvement, in percent, is:

$$\frac{82.76 - 78.75}{79.75} \; 100 = 3.77\%$$

Since approximately 15 percent of the fuel energy is extracted by the turbines (for electric

generation), the fuel savings due to the turbine-alternator system optimization will be

$$0.15\ (3.77) = 0.566\%$$

ECONOMICS AND COST JUSTIFICATION FOR THE POWERHOUSE IMPROVEMENTS

The savings obtained from turbine and boiler system optimization have been discussed previously. There are additional fuel savings available using the Supervisory Computer System.

Evaluation of capital equipment, frequently, is done using a "Return on Investment" (ROI) criteria. ROI is defined as:

$$ROI = \frac{\text{Savings} - \frac{\text{Cost}}{\text{Depreciation Period}}}{\text{Cost}}$$

Figure 12 summarizes the savings due to the computer system. A reduction of 0.984% in fuel expenditure will result in an annual savings of $511,680. This corresponds to a "Return on Investment" (ROI) value for a system of installed cost of $812,500 and depreciation period of 10 years as:

$$ROI = \frac{511,680 - \frac{812,500}{10}}{812,500}\ 100 = 52.98\%$$

Summary

The powerhouse energy management system justification can be summarized as follows:

Annual Savings by Bailey Conserver™ Control System ($46,733 savings for each boiler) - $373,856.00

Annual Savings by Supervisory Computer System - $511,680.00

Total Annual Savings - $885,536.00

Total Cost of Powerhouse Energy Management System (Conserver and Computer System Installed): - $1,462,500.00

ROI (for 10 years' depreciation) =

$$\frac{885,536 - \frac{1,462,500}{10}}{1,462,500}\ 100$$

ROI = 50.55%

NOTE: The computer system cannot provide the savings listed above by itself; it must be combined with the Bailey Conserver™ Control System.

Additional Benefits

The powerhouse energy management system will provide the following additional benefits:

1. Diagnosis of malfunctioning and poor performing components for preventive maintenance.
2. Further savings over estimated values of optimization wherever the efficiencies vary more than that used in this evaluation.
3. Increased life of boilers which will result in an increased amortization period.
4. Complete monitoring, alarming, and reporting of critical plant parameters.
5. Programmable features such as troubleshooting, learning, etc.

No attempt was made to put the specific dollar values on the above items because they would be subjective in nature and be subject to individual evaluation due to operating practices. It is, however, recommended that estimates be generated to further justify the recommended system.

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APPENDIX A

Least Squares Estimate

Consider set of points (f_i, m_i), $i = 1,\ldots,n$.

where n = number of measurements.

$$f = am^2 + bm + c \tag{A1}$$

The sum of squares,

$$I = \sum_{i=1}^{n} (m_i - am^2_i - bm_i - c)^2 \tag{A2}$$

I depends on a, b, c. A necessary condition is:

$$\frac{\partial I}{\partial a} = \frac{\partial I}{\partial b} = \frac{\partial I}{\partial c} = 0 \tag{A3}$$

Substituting for I,

$$\left.\begin{aligned} cn + b\sum_{i=1}^{n} m_i + a\sum_{i=1}^{n} m_i^2 &= \sum_{i=1}^{n} f_i \\ c\sum_{i=1}^{n} m_i + b\sum_{i=1}^{n} m_i^2 + a\sum_{i=1}^{n} m_i^3 &= \sum_{i=1}^{n} m_i f_i \\ c\sum_{i=1}^{n} m_i^2 + b\sum_{i=1}^{n} m_i^3 + a\sum_{i=1}^{n} m_i^4 &= \sum_{i=1}^{n} m_i^2 f_i \end{aligned}\right\} \tag{A4}$$

Equation (A4) can be represented in the form of:

$$MX = Y \tag{A5}$$

where:

$$M = \begin{bmatrix} n & \Sigma L_i & \Sigma L_i^2 \\ \Sigma L_i & \Sigma L_i^2 & \Sigma L_i^3 \\ \Sigma L_i^2 & \Sigma L_i^3 & \Sigma L_i^4 \end{bmatrix} \tag{A6}$$

$$X = \begin{bmatrix} c \\ b \\ a \end{bmatrix}, \quad Y = \begin{bmatrix} \Sigma e_i \\ \Sigma L_i e_i \\ \Sigma L_i^2 e_i \end{bmatrix}$$

The solution to (A6) is written in matrix form as:

$$X = M^{-1}Y \tag{A7}$$

where M^{-1} can be easily found for a 3 dimension matrix. Other methods can also be used for solving equation (A7).

In our case, a computer program is used to find the polynomial from test data.

APPENDIX B

Method of Turbine Performance Measurement & Load Optimization

Turbine performance can be evaluated in many ways, one of which is by the enthalpy-drop method (ASME PTC-6S). All turbine stages, except the first and last, can be evaluated using this method. The first and last stage are excluded because the turbine first stage performance is affected by load variations and the last stage performance is affected by both load and condenser pressure variations.

To briefly explain, each turbine stage is an isentropic expansion; thus, if the stage inlet and outlet conditions are known, the stage efficiency can be calculated. Efficiency is obtained from the ratio of the actual energy (enthalpy) loss to the theoretical enthalpy loss at constant entrophy.

$$\eta_T = \frac{H_i - H_o}{H_i - H_s}$$

where,

η_T = Turbine stage efficiency

H_i = Stage inlet enthalpy

H_o = Stage outlet enthalpy

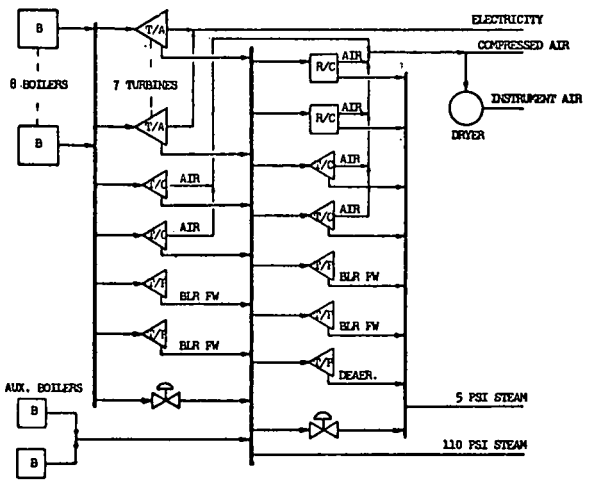
H_s = Stage outlet enthalpy if isentropic expansion

Of course, this method does not provide exact values of efficiency; but we are interested not in absolute efficiency but the relative efficiency of

one machine relative to the others.

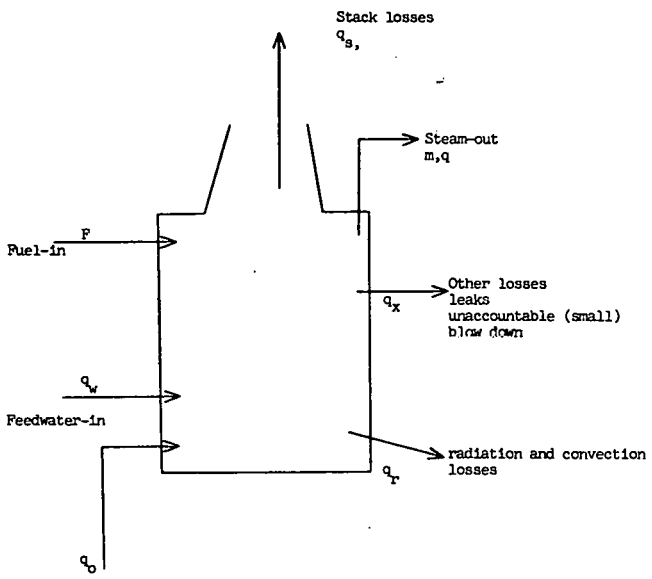
The turbines are fed from a common steam line at 850 psi, and the alternators are connected to a common feeder. Therefore, the optimization method of the turbine system will be identical to that for the boiler system.

The method is given in the text of the paper and will not be repeated here.



SCHEMATIC OF POWERHOUSE

FIGURE 1



Heat credits
Sensible heat of fuel, entering air, atomizing steam (function of temperature and specific heat)

Note
All units are in MKB/hr (10^6 Btu/Hr except m which is in Lbs/Hr)

BOILER HEAT BALANCE

FIGURE 2

Input-Output Method

Measurement	Measurement error, per cent	Error in calculated Steam Generator Efficiency, per cent
(1) Weigh tanks (calibrated scales)	±0.10	±0.10
(2) Volumetric tanks (calibrated)	±0.25	±0.25
(3) Calibrated flow nozzle or orifice including manometer	±0.35	±0.35
(4) Calibrated flow nozzle or orifice including recorder	±0.55	±0.55
(5) Coal scales – Batch or dump (calibrated)	±0.25	±0.25
(6) Uncalibrated flow nozzle or orifice including manometer	±1.25	±1.25
(7) Uncalibrated flow nozzle or orifice including recorder	±1.60	±1.60
(8) Fuel heating value (coal)	±0.50	±0.50
(gas and oil)	±0.35	±0.35
(9) Reheat flow (based on heat balance calculations)	±0.60	±0.10
(10) Superheater outlet temperature (calibrated measuring device)	±0.25	±0.15
(11) Superheater outlet pressure (calibrated measuring device)	±1.00	±0.00
(12) Reheater inlet and outlet temperature (calibrated measuring device)	±0.25	±0.10
(13) Reheater inlet and outlet pressure (calibrated measuring device)	±0.50	±0.00
(14) Feedwater temperature (calibrated measuring device)	±0.25	±0.10

PROBABLE MEASUREMENT ERRORS
AND RESULTING ERRORS IN EFFICIENCY CALCULATIONS

FIGURE 3A

Heat Loss Method

Measurement	Measurement error, per cent	Error in calculated Steam Generator Efficiency, per cent
(1) Heating value (coal)	±0.50	±0.03
(gas and oil)	±0.35	±0.02
(2) Orsat analysis	±3.00	±0.30
(3) Exit gas temperature (calibrated measuring device)	±0.50	±0.02
(4) Inlet air temperature (calibrated measuring device)	±0.50	±0.00
(5) Ultimate analysis of coal (carbon)	±1.00	±0.10
(hydrogen)	±1.00	±0.10
(6) Fuel moisture	±1.00	±0.00

PROBABLE MEASUREMENT ERRORS
AND RESULTING ERRORS IN EFFICIENCY CALCULATIONS

FIGURE 3B

BOILER \ VALUES	EXISTING OXYGEN	EXISTING AVERAGE
1	1.4-3.5	2.45
2	0.9-2.4	1.65
3	1.0-1.5	1.25
4	0.7-1.3	1.00
5	1.1-1.6	1.35
6	0.8-2.2	1.50
7	0.8-1.3	1.15

OXYGEN IN FLUE GAS

FIGURE 4

Boilers \ Values	Efficiency η,%	$K_s=(K/\eta)$
1	88.46	0.004910
2	87.33	0.004974
3	85.19	0.005098
4	86.09	0.005046
5	88.63	0.004902
6	87.83	0.004946
7	87.24	0.004978

COST FUNCTIONS $f' = K_s m$
FOR BOILERS USING K = 0.4344

FIGURE 5

Boiler	Steam Load KLbs/hr	Capacity KLbs/hr
1	135	175
2	160	175
3	160	175
4	215	225
5	190	225
6	185	225
7	220	225
	1265	1425

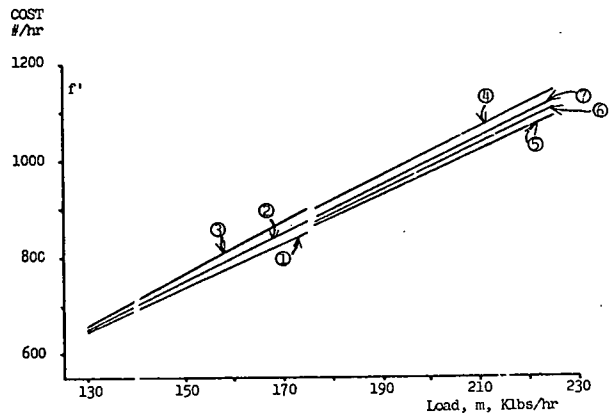
Total % Load = 88%
Operating Load Limits (KLbs/hr):
Boilers 1,2,3 $130 \leq M \leq 175$
Boilers 4,5,6,7,8 $170 \leq M \leq 225$

Notes:

1. Operating Load Limits can be assigned as desired.
2. Boiler number 8 was out of service for its annual inspection outage and was unavailable for tests during the survey period.

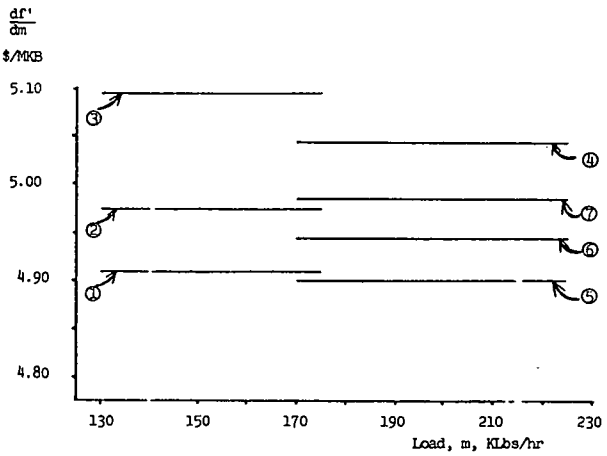
BOILER OPERATING CONDITIONS

FIGURE 6



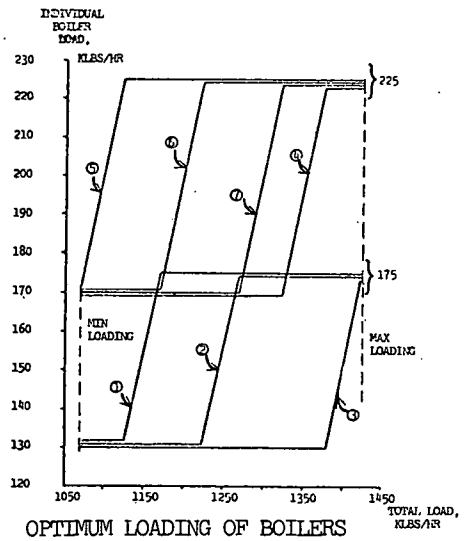
BOILER COST CURVES

FIGURE 7



INCREMENTAL COST OF BOILERS

FIGURE 8



OPTIMUM LOADING OF BOILERS

FIGURE 9

Boiler \ Values	Present Loading KLbs/hr	Optimum Loading KLbs/hr	Efficiency %
1	135	175	88.46
2	160	170	87.33
3	160	130	85.19
4	215	170	86.01
5	190	225	88.63
6	185	225	87.83
7	220	170	87.24
Overall Efficiency %	87.22	87.41	

COMPARISON OF PRESENT AND OPTIMUM LOADINGS OF BOILERS FOR 1265 KLBS/HR TOTAL LOAD

FIGURE 10

VALUES TURBINES	PRESENT LOADING MW	OPTIMUM LOADING MW	TURBINE EFFICIENCY %
1	6.1	4.5	73.2
2	4.0	4.5	82.2
3	7.5	9.5	82.4
5	7.4	7.1	81.3
6	7.5	6.0	72.5
7	7.6	9.5	86.8
OVERALL EFFICIENCY	79.75%	82.76%	

COMPARISON OF PRESENT AND OPTIMUM LOADING OF TURBINES FOR A TOTAL LOAD OF 40.1 MW

FIGURE 11

SOURCE OF SAVINGS	ESTIMATED FUEL SAVINGS %
Boiler System Load Optimization	.218
Turbine System Load Optimization	.566
Blow Down Reduction	.1
Reduced Soot Blowing*	.1
TOTAL SAVINGS	.984

*Reduced soot blowing results in energy saving and increased boiler life due to reduced tube erosion.

FUEL SAVINGS DUE TO THE SUPERVISORY COMPUTER SYSTEM

FIGURE 12

INDUSTRIAL BOILER OPTIMIZATION UTILIZING CO CONTROL

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ABSTRACT

Escalating energy costs have caused industry to search the technical section for the current state-of-the-art in combustion and control technology for power generation. Long a forgotten area in many industrial facilities, today the steam generating complex is the focus of many corporate and plant managers.

This paper discusses the approach of a large chemical company that is effectively utilizing a direct digital control (DDC) system coupled with the measurement of carbon monoxide to optimize boiler combustion and generate steam in the most cost effective manner.

Significant reductions in the amount of excess air have resulted from the use of CO as a control parameter. Previously, combustion effectiveness was determined by the more typical O_2 measurement. For reasons of boiler leakage and gas stratification, this control technique was not suitable when operating close to stoichiometry.

The use of DDC type control in our multiple boiler installation has also enabled the intelligent allocation of boiler capacity by evaluating steam demand versus incremental boiler steam cost. The system selectively increases or decreases boiler loads within specified constraints to provide the lowest overall steam production cost while continuing to meet the steam demand.

INTRODUCTION

The steam generating facility consists of four No. 6 oil fired boilers with an installed capacity of 500,000 lbs/hr. Each boiler was previously designed to operate with excess oxygen as the control parameter. By and large the existing boiler control systems functioned as designed. However, with low excess air burners operating over wide turndown ranges, oxygen measurement and control was sometimes unreliable. For reasons of air leakage into the boiler, difficulties in measuring low oxygen content of the flue gas and gas stratification, O_2 control was unsuitable for continuous low excess air operation.

The prospect of measuring carbon monoxide on a reliable basis for combustion control would eliminate the problems and limitations we encountered with O_2 control.

Through the use of a new flue gas analyzer marketed by Measurex Corporation of Cupertino, California, it is possible to accurately measure CO, CO_2 and opacity of the flue gas stream. These values can then be utilized in an integrated direct digital control system to control boiler combustion parameters as well as many of the other control functions of a steam generating facility.

CO CONTROL APPROACH

When concerned about combustion efficiency, one must provide sufficient air to support combustion to completion but not in excess amounts so as to cause additional heat losses. The amount of air in excess of stoichiometry to assure complete combustion is a function of many variables. These include, fuel type and composition, fuel and air temperatures, boiler geometry, boiler load and the mechanics of fuel/air mixing.

Typically, the parameter that is measured to control excess air is the amount of oxygen in the flue gas stream. While this does correlate to the amount of excess air, it can be misleading.

Excess O_2 is inferred to be what is leftover after complete combustion, when in fact, quantities of unburned combustible material may continue to be present in the flue gas stream. This represents fuel losses and can present hazardous furnace conditions.

Balanced draft or negative pressure type boilers are characteristically subject to air infiltration regardless of how carefully they are sealed. This air in-leakage (tramp air) causes oxygen measurements that may be mistaken for air that was involved in the combustion process. Without constraints on unburned combustibles, this common situation on O_2 control could provide a fuel rich and dangerous condition in the boiler. To avoid this situation, operators will operate with high excess air quantities providing a "comfortable" margin of safety that is also costing significantly in energy dollars.

A measurement to determine combustion completeness is necessary to assure maximum thermal efficiency with safety of operation. That parameter is carbon monoxide.

CO as an intermediate combustion product correlates directly to completeness of combustion. Field data relating CO, excess air, excess O_2 and boiler efficiency is shown in Figure 1 for a particular solid fuel (1). As indicated, the maximum thermal efficiency occurs at some unique point where there is a minimum amount of excess air and about 150 - 300 ppm of carbon monoxide. It is important to note that although this operating point is unique for each boiler and type of fuel, the amount of CO (the target) for optimum boiler efficiency will remain constant. The slope of the oxygen curve is specific to each application and fuel type. This provides an added advantage for CO control since its target is insensitive to fuel type. This is particularly attractive when burning multiple fuels. CO measurement also is not affected by air leakage into the boiler since the quantity of CO in atmospheric air is negligible.

The CO measurement grows exponentially as stoichiometry is approached while O_2 measurement on the other hand decreases nearly linearly over the same range. These facts, in addition to the fact that CO is an order of magnitude more sensitive than an O_2 measurement, makes CO 10 to 20 times more accurate than O_2 as a control signal (2).

In addition to the limitations already mentioned, most oxygen sensors are of the point source type. Measurements are taken in the flue gas stream at which is thought to be a representative sample point. Tests have shown that there exists flue gas stratification by constituents in the duct work stream (3) that leads to unreliable measurement without making an average of several measurement points.

Through the use of a new digital based flue gas analyzer marketed by Measurex Corporation of Cupertino, California, it has been possible to accurately and reliably measure the constituents of CO and CO_2 as well as the opacity of the flue gas stream. Additional measurement capabilities that are available include SO_2 and NO for emission monitoring.

The analyzer is based on the principle of wavelength absorption and is mounted directly in the flue gas stack or ductwork. CO and CO_2 are measured with the infrared light spectrum; SO_2 and NO, the ultraviolet spectrum; and opacity, the visible light spectrum. This paper does not deal with SO_2 and NO measurement.

These various wavelengths are projected across the flue gas stream to a receiver where signals are relayed to a digital computer for use. The problems frequently associated with "across-the-stack" type analyzers have been successfuly solved. In addition, the limitations that plagued previous CO type analyzers have been resolved in the Measurex unit, namely calibration and accuracy.

The Measurex analyzer conducts computer initiated on-stream calibration procedure. At pre-determined intervals the system goes through a zero and span calibration for CO, CO_2 and opacity and calculates correction factors that are stored in the computer. These factors then provide for consistently accurate results. The uptime demonstrated at our plant after the startup phase ranged from 98.5% to 100% depending on boiler.

INITIAL RESULTS OF CO CONTROL

Figures 2 and 3 show initial control results on one boiler that are plotted over a period of approximately 16 minutes. Figure 2 plots air/fuel ratio versus excess O_2 and CO. Figure 3 plots steam flow versus excess O_2 and exit gas temperature. The sample rate is every 20 seconds and the measurement ranges are as shown.

After obtaining baseline data for the first few minutes, the control was switched from analog control with O_2 trim (O_2 setpoint determined visually by the operator observing the stack) to DDC with CO control. The steam load of the boiler remained essentially constant.

In approximately 10 minutes there was an efficiency improvement for that particular boiler of about 1.3%. As tuning of both the analog controls and DDC controls progressed, efficiencies were improved and differences narrowed.

Throughout a period of two months, data were gathered by the computer system while operation was carried out by the operators utilizing the analog control with O_2 trim. Periodically, the DDC system was put on-line with CO control to determine its comparative effectiveness. When comparing the analog and DDC control systems, it's important to know that the powerhouse operators are experienced and aware of the efficiency of operation. This is particularly significant when operating on the analog system since setpoints must be continuously adjusted by the operators to assure maximum efficiency. Over this time period the Measurex computer based DDC system improved individual boiler efficiencies from 0.83% to 1.25% on combustion control alone. Needless to say, without experienced operators, the incremental improvement would have been greater.

LOAD ALLOCATION CONTROL STRATEGY

In addition to air/fuel ratio control utilizing CO, several other loops were handled by the Measurex computer in a DDC mode. These included control of furnace draft and the plant master as well as measurement inputs for steam and water flows, boiler and stack temperatures and drum level.

The plant master control is used to maintain a fixed steam pressure from the boilers. An increase or decrease in this pressure signifies increases and decreases in steam demand. The plant master controller must react accordingly to maintain plant header pressure constant with the normal fluctuations in plant steam demand.

A normal analog type plant master controller sends a fixed percentage signal to each

individual boiler master for load changes. Each boiler in turn has a biasing controller with which the operator may manually bias this signal to allocate more or less load to that particular boiler.

Even in identically designed boilers, operating characteristics such as stack temperature, percent excess air, blowdown, radiation loss and tube scaling can vary drastically. These parameters have significant affects on boiler efficiency. Since these characteristics are continuously changing, it would be desirable to be able to generate at will more steam from the most cost efficient boiler.

Use of the Measurex system to perform a plant master function based on boiler efficiencies has proven to be cost effective. Every 20 seconds, those parameters that affect boiler efficiency are measured, converted and sent to the computer where a series of calculations are performed to determine individual boiler efficiency.

When two or more boilers are on the computer optimizing plant master, load is allocated to the boiler that is most cost effective. Steam cost is used as the criteria and is based on boiler efficient fuel cost and fuel type.

The computer generates real-time efficiency curves versus load for each boiler and in this way can predict how to shift steam load to produce steam with the least cost.

In addition to monitoring boiler efficiencies, operating constraints must be considered when changing loads on a boiler. Drum level and furnace draft upsets are examples of conditions that need to be considered. With DDC control these sudden upset conditions can be predicted and used as feedforward signals to the load allocation strategy. Consequently, load shifts are performed for cost benefits, but not without consideration for minimizing boiler upsets. For instance, if a particular boiler was determined to be the most cost effective at the time of a load demand, but was experiencing an operating constraint or upset condition, load would then be allocated temporarily to the next most efficient boiler.

Boiler operating limits can be easily entered by the operator for maximum and minimum steam and oil flows, drum level fluctuations, furnace draft, excess O_2 and CO. These limits aid in safe and efficient operation allowing the operators total control at all times. Boilers may participate in the load allocation program at any time at the discretion of the operators.

The savings due to the load allocation program are difficult to document, but it has been observed that loads are being switched as efficiencies change due to sootblowing and other conditions. Preliminary data indicates that up to 1% reduction in total fuel usage can be expected.

SUMMARY

Management's decision to optimize the steam generating facility was based on the goal to minimize powerhouse costs subject to minimum and maximum constraints on individual boilers while meeting the steam demand.

The results documented to date are encouraging. CO control has indeed provided for a means to optimize the combustion process, while the incorporation of computer based DDC control has given tremendous flexibility for sophisticated control strategies such as load allocation. Increased operating experience with this system promises to open new areas and provide better ways to accomplish boiler control.

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3. Gregory, M. W., Crawford, A. R., Manny, E. H., and Bartok, W., "Determination of the Magnitude of SO_2, NO, CO_2, and O_2 Stratification in the Ducting of Fossil Fuel Fired Power Plants", APCA, June, 1976.

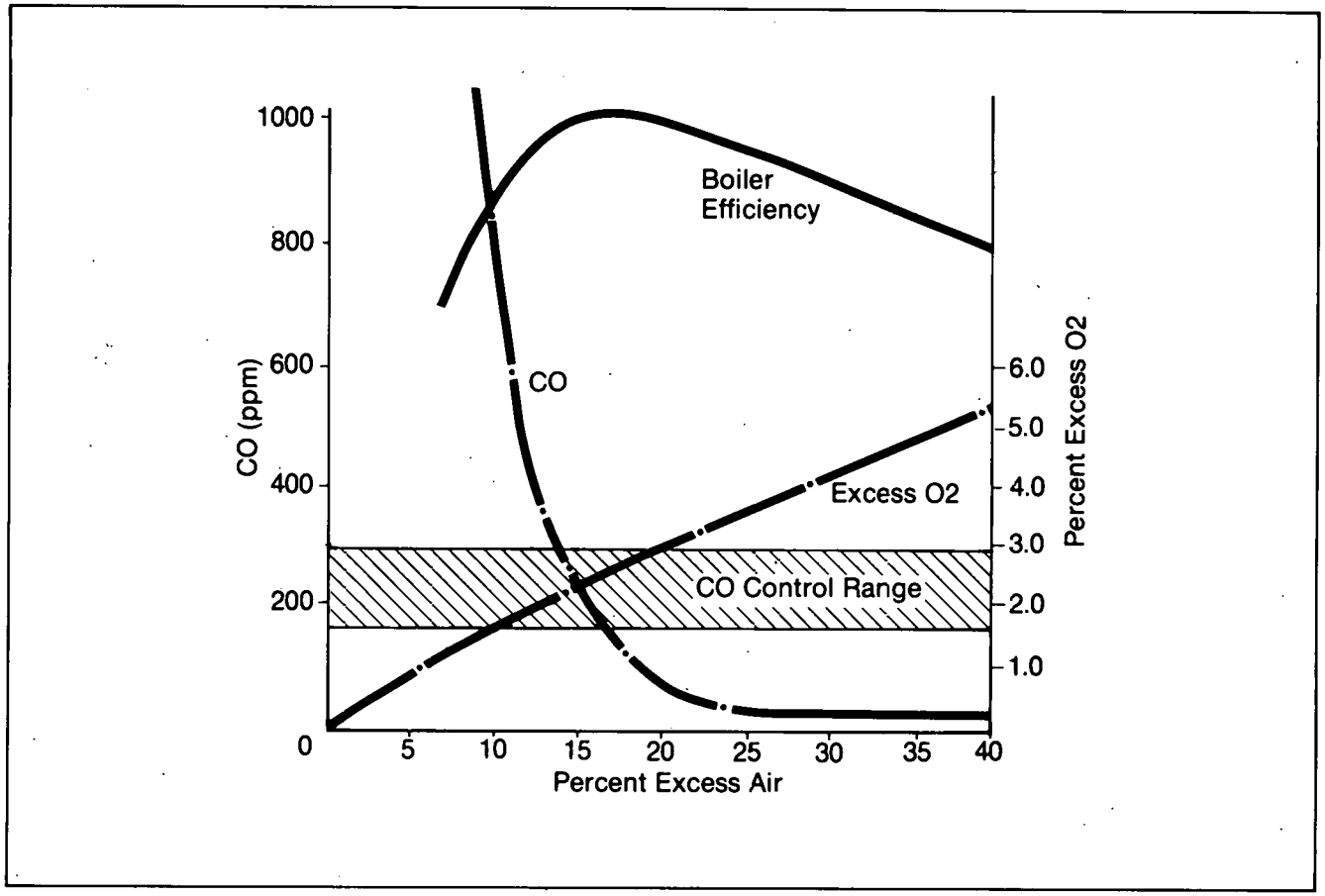


FIGURE 1. FIELD DATA RELATING CO, EXCESS AIR AND OXYGEN FOR A SOLID FUEL

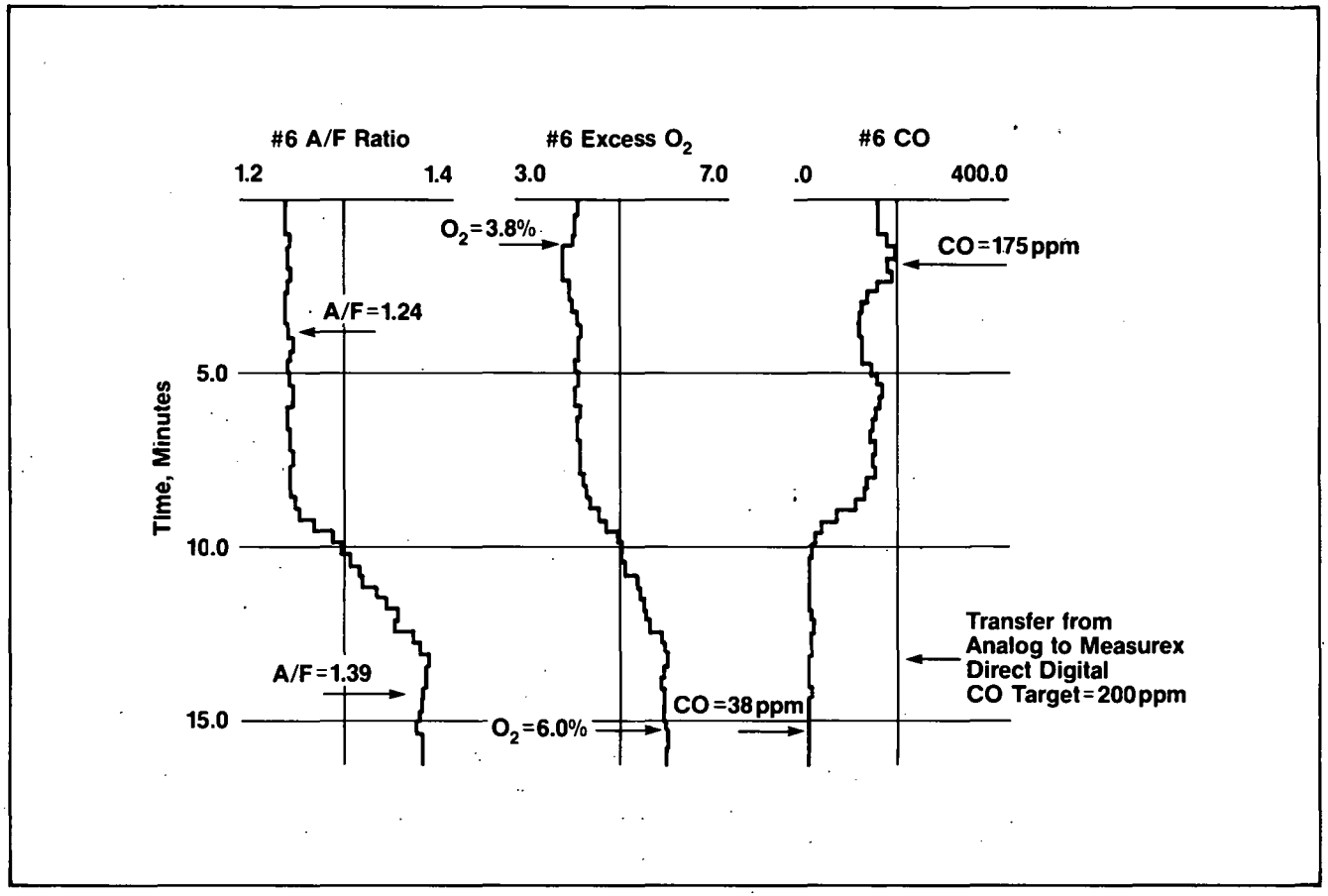


FIGURE 2. CO BASED COMBUSTION CONTROL RELATING: A/F RATIO, EXCESS O_2, CO

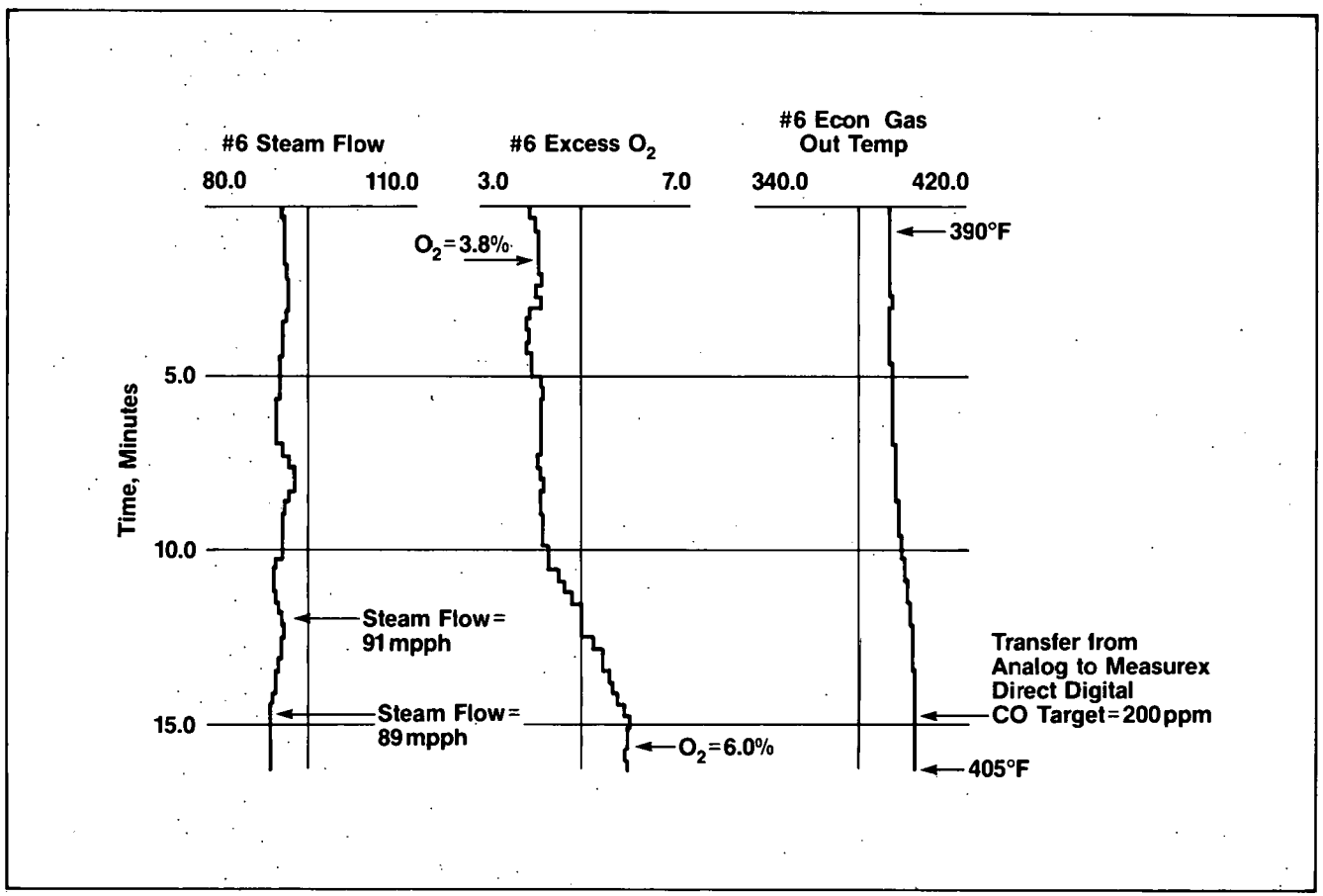


FIGURE 3. CO BASED COMBUSTION CONTROL RELATING: STEAM FLOW EXCESS O_2, GAS TEMPERATURE

IMPROVED DRAGLINE UTILIZATION

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ABSTRACT

The cause of energy conservation can be served by increasing the efficiency of large draglines used in surface coal mining. The topic is the application of a training simulator, computer instrumentation and computer simulation to improve dragline operator skill, decrease downtime and optimize the digging strategy of the machine. The training simulator is a TV model system which the trainee controls from a simulated cab. Dragline instrumentation is achieved by a computer, a control/display console for the operator and sensors mounted throughout the dragline. The dragline simulation model is a computer program to determine production as a function of overburden properties, dragline specifications and removal strategy. The simulation model used in conjunction with the recorded data from the on board system provides a basis for the evaluation and optimization of dragline operating procedures. The dragline simulator, display and recording system and simulation model were initially developed under contract with the Department of Energy.

Realizing the role of efficient surface coal mining in meeting the need to use energy wisely, McDonnell Douglas Electronics Company (MDEC) began studies of large walking draglines in 1972. With its aerospace background, MDEC was familiar with the benefits of simulation and instrumentation in reducing energy consumption and improving the efficiency of aircraft operation. Techniques such as training pilots with simulators, providing the pilot with constant feedback on the performance of the airplane through sophisticated instrumentation, and the use of simulation models to analyze aircraft flight trajectories could prove effective in improving dragline utilization.

Simulators are used extensively to train pilots by both the military and commercial airlines. An aircraft simulator usually consists of a cockpit mounted on a motion base, a visual scene generation device, instructor console and a computer system. The trainee operates the controls of the simulated cockpit. These actions are processed by the computer which commands the appropriate responses in the cockpit instruments, motion base and visual scene. Operating costs for a simulator are typically one-tenth that of the actual aircraft. For a wide-body airliner, fuel and oil costs alone can exceed $2,000 per hour. Compared to this the energy consumption of a simulator is insignificant. Not only is the simulator more economical to operate but offers advantages of safety to the trainee and the capability to expose the trainee to emergency procedures that would not be possible in the actual aircraft. The simulator is also more flexible, allowing the instructor to place the trainee in a variety of training situations with the push of a button.

When flying a commercial aircraft, the pilot has instruments to provide precise information on the aircraft's location and performance relative to a prescribed flight plan. This flight plan is predetermined and has as a major criteria the efficient use of fuel.

Operation of a dragline similar to a large commercial aircraft requires maximum utilization in an efficient manner. In surface mines using large draglines, the dragline is nearly always the primary stripping machine, and, as such, determines the productivity of the mine. An estimated 30 percent of the annual U.S. coal production is uncovered by draglines.

In order to better understand the operation of the dragline in a surface mine consider the following data which is representative of a midwestern coal

mine using a large dragline.

Average Overburden Height	100 Feet
Average Coal Seam Depth	7 Feet
Boom Length	300 Feet
Bucket Capacity	100 Cubic Yards
Average Cycle Time	60 Seconds
Bucket Fill Factor	.85
Dragline Availability	.70
Percentage Rehandle	10%

This dragline will make 367,000 cycles per year. It will remove 28,069,000 cubic yards of overburden which will uncover 2,005,000 tons of coal. In doing this it will consume over 15 million kilowatt hours of electrical energy. Operating a dragline is a job where seconds count. A decrease of one second in the average cycle time would increase yearly production of coal by over 33,000 tons.

Typically, an individual becomes a dragline operator after serving an apprenticeship as the machine oiler. The oiler relieves the operator during breaks and develops the skill to control the machine through on the job training. The ability to smoothly and efficiently operate a dragline does not come easily. It may take an individual several years after becoming an operator to develop the skills to properly operate the machine. Unlike the aircraft pilot, the operator has virtually no aids in the dragline cab to indicate his performance other than his own feeling of cadence and sense of time. He must rely on skill and concentration to maintain efficient operation throughout his shift. Although operating a dragline is a less sophisticated task and involves less of a safety risk, in many ways it is more demanding. There is no copilot with a duplicate set of controls or automatic pilot to take the routine out of operating the dragline.

In order to develop technology to improve dragline utilization MDEC began working with first the Bureau of Mines and presently has several contracts with the Department of Energy. These efforts include the development of a dragline training simulator, an operator display and recording system, and a dragline computer simulation model. Each development and its contribution to more efficient dragline operation is described in the following paragraphs.

DRAGLINE TRAINING SIMULATOR

The motivation behind the development of the dragline simulator and related training materials was to reduce on the job training and make the operator's first day on the job more productive. The training simulator, shown in Figure 1, is a TV model system in which the trainee operates a 1/60 scale model in a similarly scaled mine environment from a simulated cab. The cab is identical to that of an actual dragline with the same hoist, drag and swing controls. A closed circuit TV camera, mounted on the model, is used to view the scene which is rear projected via a CRT projector onto a screen in front of the trainee. The trainee sees a scene of a dragline operating in a mine. The hoist, drag, and swing performance of the model is appropriately scaled to give the trainer feel of operating an actual dragline. Trainee control commands are input to a minicomputer which drives the model. A second projection system using a servoed 35mm projector gives the trainee a side view of the fairlead and drag cables. The instructor can critique the trainee's techniques from a seat behind the trainer. Simulator training is supported by related lesson plans on proper operating procedures. This training system, now in development, will be operational by the end of the year. It is expected to contribute to both the proficiency of individual operators and to bring about more consistent dragline operating procedures.

OPERATOR DISPLAY AND RECORDING SYSTEM

The lack of instrumentation on the dragline led MDEC to pursue the development of an on board display and recording system that generates and displays performance information to the dragline operator. This information provides the operator immediate feedback on his operating procedures. The system also stores information on dragline production and downtime for later printout by mine management.

The engineering prototype, developed under contract with the U.S. Bureau of Mines and the U.S. Department of Energy, was installed on an operating dragline in November of 1977. After the successful development and testing of the prototype system several production systems have been fabricated and installed in Illinois and Indiana mines. The system consists of a minicomputer system with dual floppy disk storage, a teleprinter, sensors

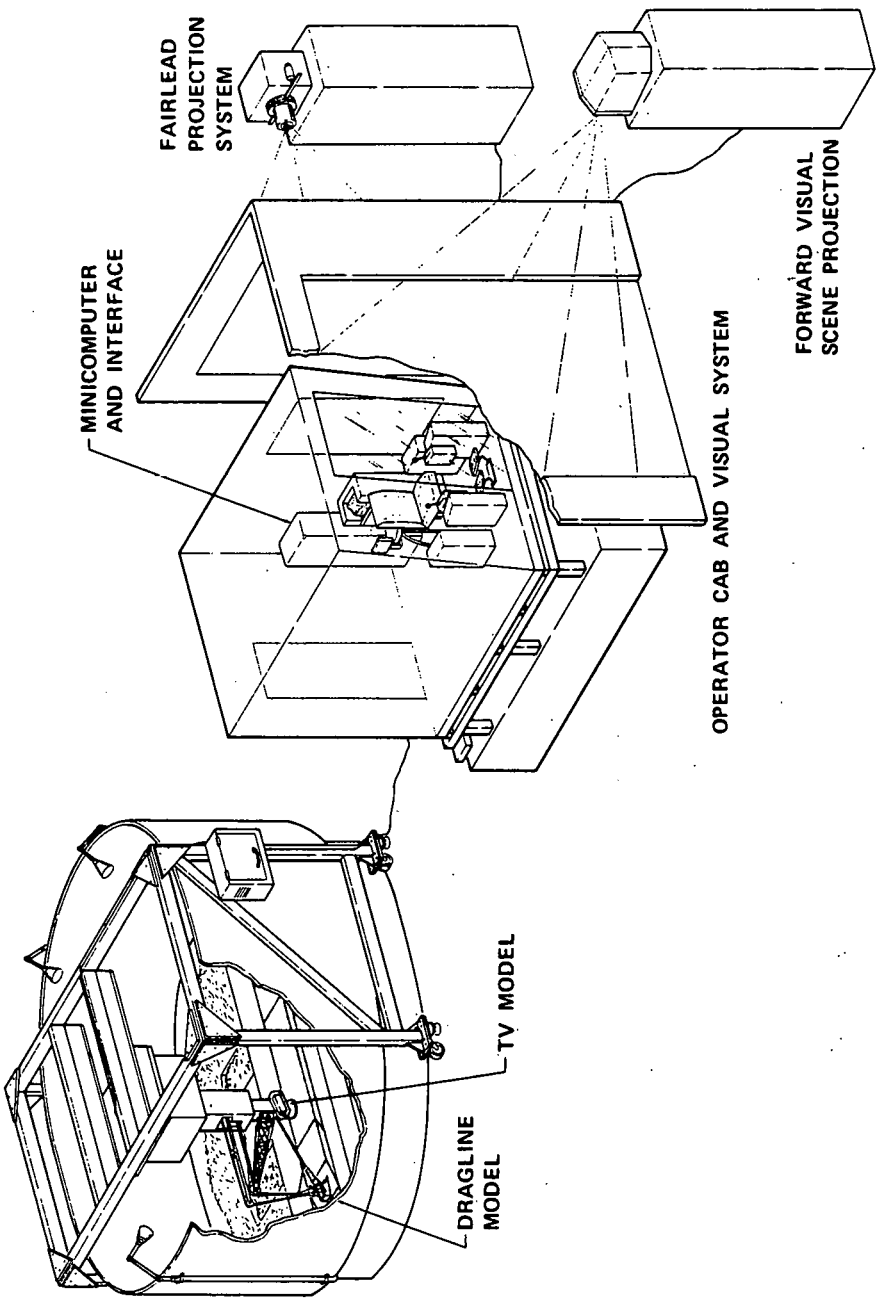


FIGURE 1

Dragline Training Simulator

monitoring dragline motion and power usage, and a control/display console for the operator. See Figure 2. Inputs of the system come from shaft encoders mounted on the hoist, drag and swing drives and from an A/D processor which monitors the current and voltage of the motors. The computer processes this data and displays performance parameters such as cycle time, load time, swing angle and bucket yardage to the operator after each cycle. Bargraphs give the operator an indication of his proficiency at loading the bucket, swinging to dump and returning to dig relative to the capability of the machine. Other bargraphs indicate the position of the bucket above or below the bench and the radial distance of the bucket from the fairlead. The operator controls the parameters displayed and enters downtime reasons through the console. Alert indicators warn the operator of improper operations such as taking an excessive number of second passes to fill the bucket or endangering the boom by pulling the bucket into it. An alert indicator also warns the operator of excessive 15 minute power demands. Typically, a noncaptive mine is assessed monthly power bills based on the greatest 15 minute average demand. The capability to monitor this 15 minute demand helps the operator identify and avoid situations that lead to exceptionally high power usage. Information on the draglines performance including a downtime history is recorded on the floppy disk units. Reports on the dragline activity can be printed out for any time interval or operator. This provides mine management and operators with a detailed data base from which to analyze and improve dragline operation.

DRAGLINE COMPUTER SIMULATION MODEL

The dragline training simulator and the instrumentation provided by the on board display and recording system are efforts to obtain and reinforce efficient operation of the dragline. However, the operator must also be concerned with the procedure used to remove overburden. Parameters such as the pit width, cut length, dragline position and bench depth affect the efficiency of the removal process. In conjunction with the development of the display and recording system, MDEC developed a dragline computer simulation model. The model is a computer program that simulates dragline operations in order to determine dragline productivity as a function of the machine characteristics, mine environment and removal procedure.

The process of removing overburden is simulated on a cycle by cycle basis. Overburden and spoil areas are modelled in the computer by a 256 yard by 484 yard grid. Up to five layers of overburden can be simulated. Properties of each layer are strata thickness, angle of repose, density, swell and cutting resistance. The dragline to be simulated is specified by such parameters as boom length, boom angle, fairlead radius, bucket geometry and motor performance. The overburden grid is initialized by input data which describes the mine geometry prior to the removal of a block of overburden. This input data includes pit width, bench depth, spoil contour and highwall angle. Additional parameters describe the volume of material to be removed from each dragline position.

In addition to sidecast spoiling, the simulation model can be used to simulate advance benching, extended bench and procedures used to pull back the spoils. After a removal procedure has been simulated the computer prints out results such as the strip rate, average cycle time, average swing angle and average cycle energy. A plot of the overburden and spoil grid can also be generated.

The simulation model offers a means to economically and quickly evaluate dragline operating procedures. Although the simulation results are not totally transferable to a real world situation it is a means to do extensive analysis and identify promising operating procedures which can then be field tested. Simulation runs can be made in a fraction of the time and with a fraction of the energy used to conduct field tests. Field data on dragline performance must be collected over several months for similar overburden conditions in order to average out extraneous factors such as machine wear or poor overburden blasting and isolate the effect of a particular parameter. As discussed previously, data collection on dragline operating procedures can be greatly enhanced by the on board display and recording system. The simulation model used in conjunction with this system provides a means to improve dragline utilization.

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2. A. E. Szczuka, K. L. Contor, C. W. Morris et al, "Concept Feasibility Study for Training Equipment to Improve Coal Productivity." Final Report to U.S. Department of the Interior, Bureau of Mines, under Contract No. J0255014, 2 April 1976.

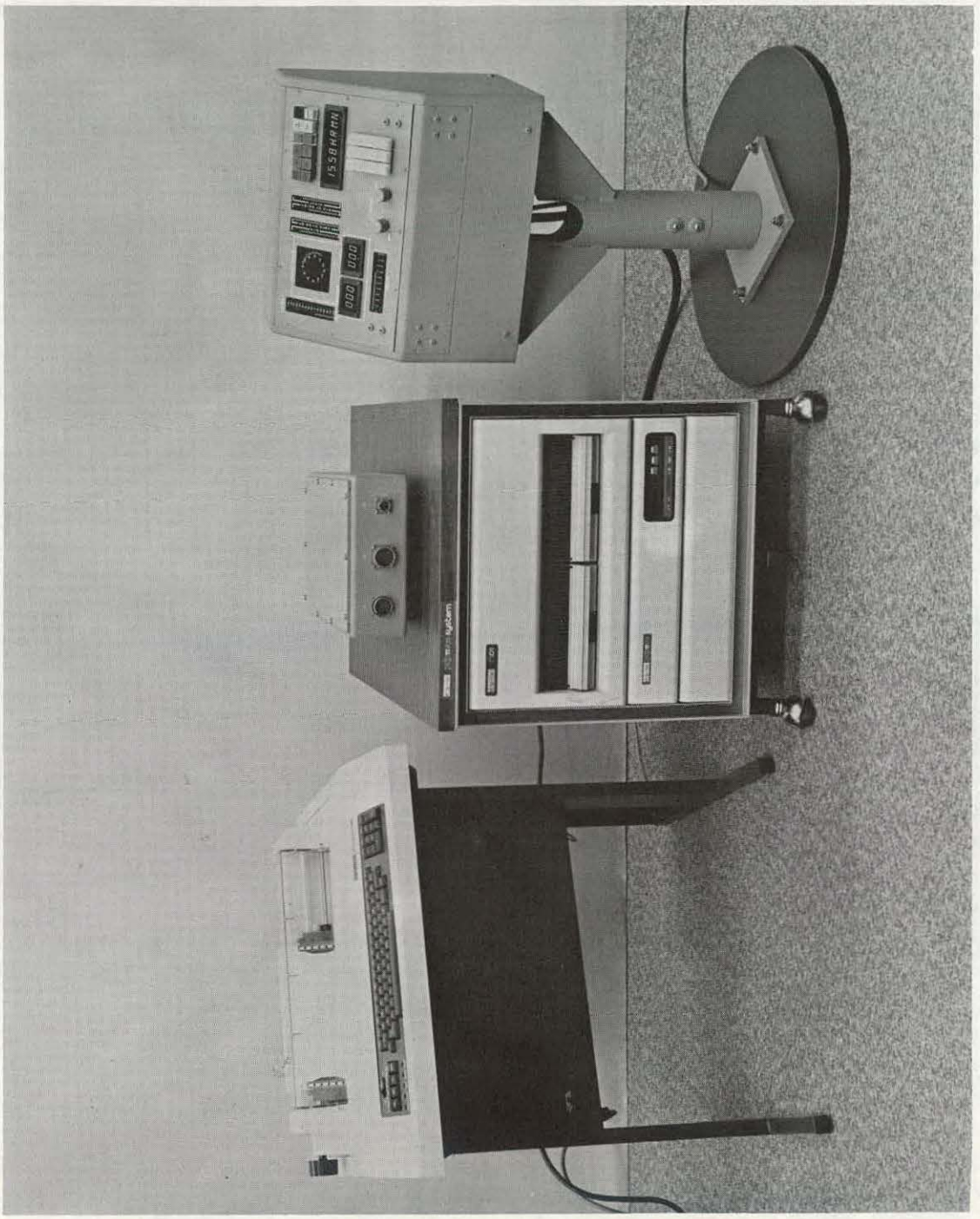


FIGURE 2
Display System Components:
Teleprinter, A/D Processor, Computer System and
Operator Console

ENERGY CONSERVATION IN FRENCH INDUSTRY AND AT RHONE-POULENC

Alain Mongon

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Paris

ABSTRACT

France imports 75% of its primary energy. In 1985 this dependence on imported energy will decrease but remain at 60%. Energy conservation and energy recovery are therefore of dramatic importance. Industry has always taken care of energy management in order to get the best production prices. But since 1973 with the help of various governmental procedures, great efforts have been made to use energy in the most efficient way. Examples are given to show : the most efficient way of energy sources management, the application of the process optimisation method, the use of control equipment for process and heating. RHONE-POULENC, the biggest chemical group in France, ranked ninth in the world, is able to cope with the challenge of the most rational use of energy. RHONE-POULENC, which is the second largest industrial energy consumer in France, has worked for energy conservation in three directions : management, education and investment. The primary energies are transformed for thermal or mechanical purposes. This transformation has to be the most efficient : combined production of heat and electricity by means of steam or gas turbines is highly developed at RHONE-POULENC. The experience of a ten gas turbine plant with heat recovery boilers is described. But the coming of nuclear energy and the scarcity and rise of prices of fossil fuels reduce the interest in combined production. The optimum use of energy in the various production processes needs investments to improve the existing plants or to build new plants designed on an entire new process. Various examples are given.

INTRODUCTION

Before giving the audience a full account of the French Industry in general and my company RHONE-POULENC in particular approaches to energy conservation from an energy recovery point of view, I would like to remind the audience of the French energy demand/supply position and the extent of our dependence on imported energy.

France imports 75 % of its primary energies such as gas, coal and oil. In 1985 this dependence will remain as high as 60% even with a nuclear power program which produce 55% of the France electricity needs.

In 1978 the energy sources were distributed as follows:

coal	17,6%	gas	11,9%	nuclear	3,5%
oil	58,6%	hydro	8,8%		

The consumption break down was in 1978 :

industry	32,5%	transport	19,3%
domestic and commerce	36,3%	energy production	11,9%

France consumes per year around 110 Million tons of oil and will pay for them 100 Billion Francs in 1980. Therefore, even with a rather low energy consumption per capita 3,5 TOE/year, France has mandatory energy conservation programs for transport, commerce, domestic and industry.

FRENCH INDUSTRY'S ENERGY CONSERVATION PROGRAM AND EXAMPLES

In 1978, 15,5 Million of TOE have been saved. Industry has contributed 3 to 3,5 M. TOE (tons of oil equivalent).

The total goal for 1985 is 35 M. TOE and for industry 15 to 16 M. TOE. This means that industry according to the governmental wishes has to double the efforts of the last years.

This result can be achieved by :

- a good energy expertise
- a better energy management
- an adaptation of the production tool (engineering and investment)
- a constant research of new processes and new technologies
- a deep education program on energy for everyone.

For industry various aids are foreseen by the government. 400 Million Francs have been allocated for 1979. The Agency for Energy Conservation (AEE) manages this fund by giving the following possibilities :

- 2.000 F (as a maximum) can be given for an energy study of a small firm (net sales of less than

200 M. F. and less than 1.000 employees)

- 50% of the price of a study for an investment which has not been realised can be paid by the AEE
  a grant of 400 F/TOE saved per year up to 20% of any primary energy saving equipment
- a grant (up to 50% of the total investment cost) for any energy saving demonstration plant
- an assistance for the development of new energy saving equipment or process to be commercialised
- a fiscal aid by accelerating the equipment depreciation time
- 70% of the energy saving equipment can be borrowed with lower interest rates.

French government expects that all these facilities will enable industry to invest 2 to 2,5 Billion Francs per year.

From January 1975, 1.200 projects have been granted : 450 Million Francs of grants for a total investment of 4 Billion Francs which could save 1.800.000 TOE. Since 1975, 140 demonstration projects have been granted.

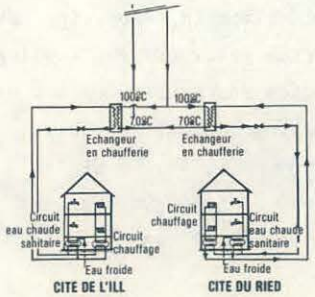
The following examples taken in various industries will show :

- the most efficient way of energy sources management
- the application of the process optimisation method
- the use of control equipment for process and heating.

1st example : The thermal effluents from a refinery may provide the heating up of a block of flats

Cooling down of the products during refining treatment results in the production of large quantities of hot water at 98°C. The SHELL refinery of REICHTSETT has designed a project to use these rejects to provide the heating up and the hot water for 3700 flats of two blocks of flats located at 6 km from the refinery. This transfer has been made via an underground to-and-fro pipe line, in heat-insulated cast iron and saves up to 8000 tons of fuel oil per year.

Investment ⟶ 20,500,000 FF
Saving ⟶ 3,000,000 FF/year
R.O.I. ⟶ 7 years

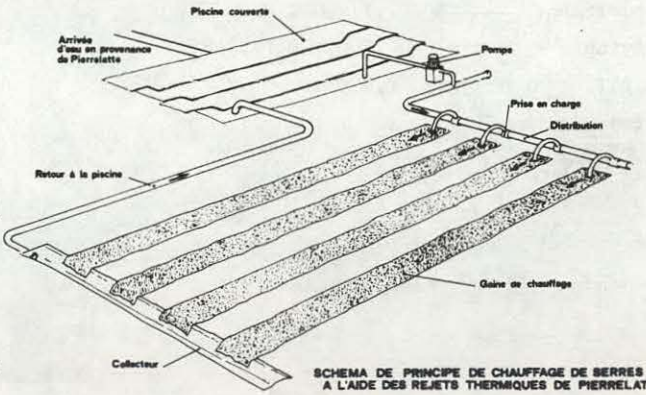


2nd example : Industrial effluents at 38°C to heat up greenhouses

An especially interesting example of use of thermal effluents is given by the operation made in PIERRELATTE where the water at 38°C rejected by the isotope separation plant is re-used to heat up 12 acres of greenhouse.

The heating up technique consists in circulating the hot water at a very low flow rate in plastic ducts placed on the ground providing an optimum heat discharge in time unit and to use the maximum of the effluent.

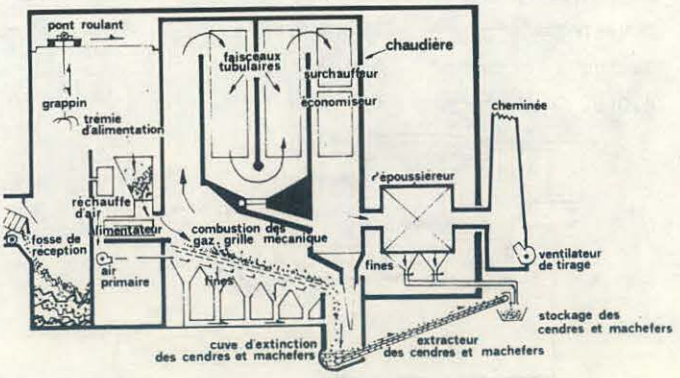
Investment ⟶ 900,000 FF
Saving ⟶ 600,000 FF/year
R.O.I. ⟶ 1.5 year



SCHEMA DE PRINCIPE DE CHAUFFAGE DE SERRES A L'AIDE DES REJETS THERMIQUES DE PIERRELATTE.

3rd example : Use of by-products as substitution fuels

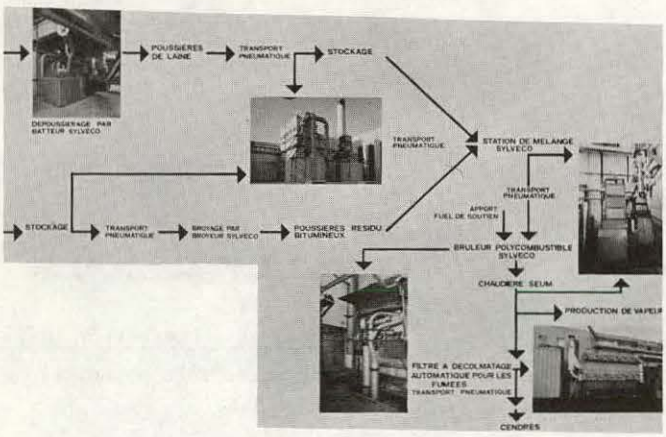
The power value of rejects and waste is a potential source for energy saving : 30 Million of tons of industrial waste and 12 Million of tons of household garbage, each year may be recovered, recycled, re-used or made to profit for their heat power. Among such waste, the utilization of wood rejects, of worn tyres, used oils not recoverable, chemical waste, plastic rejects, papers, textiles, etc may represent, in present power, a saving potential of near enough 2 Million of tons of oil per year, while giving its contribution to the quality of the environment.



4th example : It is possible to recover the energy contained in the textile combing waste

Washing of wool has a secondary result, after recovery of the wool grease from the washing water, the production of an aqueous residue containing oxided wool grease, yolk, sand and earth. The fight against pollution resulted in distillating this residue. After distillation, it remains a bituminous residue in the form of crushable small plates (ICP - 6400 BTU/lb). This residue and the wool dust may be incinerated after recovering the energy, using a pulverulent fuel burner which can operate without added fuel and adapted to standard combustion chambers. This operation has been performed by the Firm A. DEWAVRIN FILS & Cie in AUCHEL.

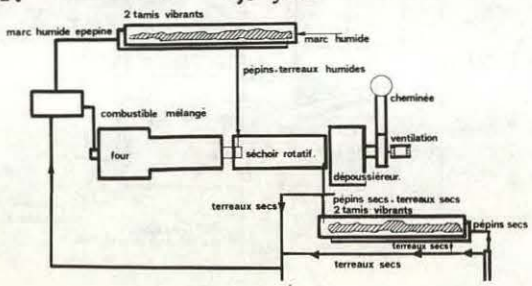
Investment ⟶ 1,725,000 FF
Saving ⟶ 600,000 FF/year
R.O.I. ⟶ 2,9 years



5th example : The by-products of grapes pomace provide a useable source of energy

The grapes pomace is generally dried in a rotary furnace, the hot gases of which are produced with a generator burning heavy fuel oil. The firm APPLITEC in Moissac decided to replace the fuel oil by the by-products of grapes marc (envelope of pips...) burned in a special hearth in the form of half-cone in tiers.

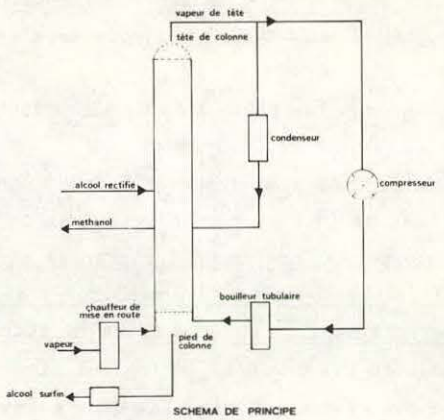
Investment ⟶ 205,000 FF
Saving ⟶ 540,000 FF/year
R.O.I. ⟶ 0,5 year



6th example : Mechanical compression of vapours : performed in the distillery VERNIERS in Narbonne

Re-distillation of alcohols requires successive utilization of three distillation columns called purifier, rectifier and methanol remover. Traditionally, these three columns are independant for the energy and each one receives at its base in the form of vapour the calories required for distillation. The operation described here consists in compressing the head vapours before recycling in the column. This compression increases the saturating temperature of the alcohol vapours and thus heats up the bottom of the column by condensation in the boiler.
The alcohol condensates are recycled in a conventional manner at the head of the column.

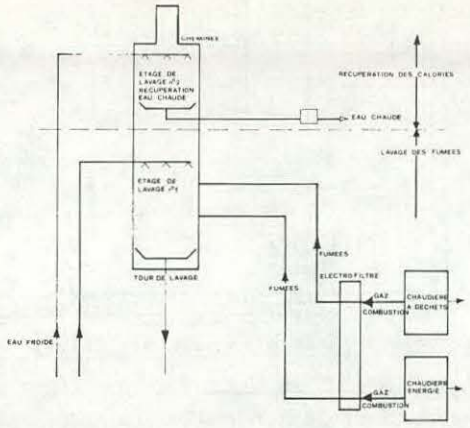
Investment ⟶ 1,720,000 FF
Saving ⟶ 400,000 FF/year
R.O.I. ⟶ 4,3 years



7th example : Recovery of calories from the combustion gases from plant waste

For the manufacture of paper pulp, an important portion of the energy required for the production of the steam utilized is supplied by the waste from the factory itself (black liquors, barks, etc).
The combustion of such waste in recovery boilers requires scrubbing of the gases before being exhausted into the atmosphere.
The operation performed at the plant AUSSEDAT-REY in Saillat-Vienne consists in recovering the calories from the combustion gases via the cooling water and using such calories for heating up new water for the process of bleaching the paper pulp.

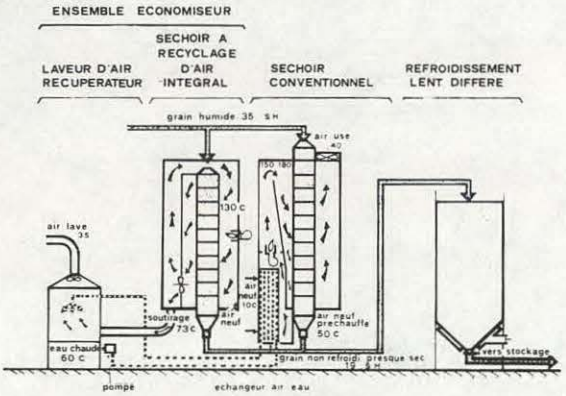
Investment ⟶ 6,940,000 FF
Saving ⟶ 5,800,000 FF/year
R.O.I. ⟶ 1,2 year



8th example : A new process to dry maize

A conventional drier, operating with gas oil and with an exchanger, consumes about 2100 BTU/lb evaporated water. But it is possible to divide by 4 the specific consumption of an additional drying plant by recovering the latent heat of the steam exhausted : this is the case of the two-stage drier, installed in the COOPERATIVE DU VALOIS.

Investment ⟶ 250,000 FF
Saving ⟶ 50,000 FF/year
R.O.I. ⟶ 5 years

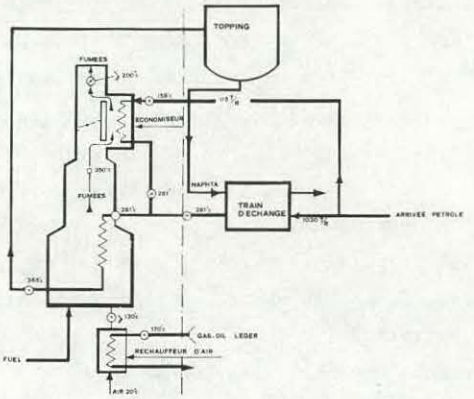


9th example : A better optimization of heat transfers also provides energy savings

The atmospheric distillation is the first refining operation performed on crude oil. It therefore concerns very large quantities of products and consists in separating by continuous distillation of the crude oil into various fractions such as gasoline, kerosene, fuel-oil.

The operation which has been made at the refinery of BP in Lavera concerns the experiment of a new heating system for the crude oil and for the combustion air : the crude oil is partly preheated, before entering into the furnace, by the fumes of the furnace and the combustion air is preheated by exchange with one of the distillation by-products. These two operations, performed for the first time provide a saving of about 15% of the consumption for this plant.

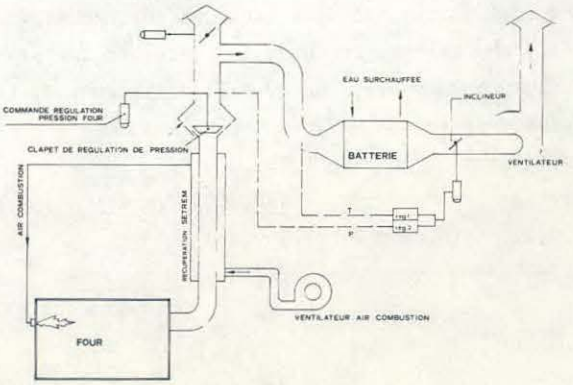
Investment ⟶ 6,130,000 FF
Saving ⟶ 4,400,000 FF/year
R.O.I. ⟶ 1,4 year



10th example : The heating power of the fumes from the furnace can be fully used for the production of hot water

The fusion furnace for light alloys, reflector type, heated with natural gas or fuel oil, generate fumes coming out at 1100/1250°C and generally passing through heaters for the combustion air, where their temperature drops to 850°C at least, as the hazards of cracking of the fuel in the burners do not permit a greater heating of the combustion air. But it is however possible to still recover some calories from the fumes by cooling them down to 250°C in a second stage of recovery which will produce overheated water for the plant distribution network. This operation has been performed by CEGEDUR PECHINEY in Neuf Brisach.

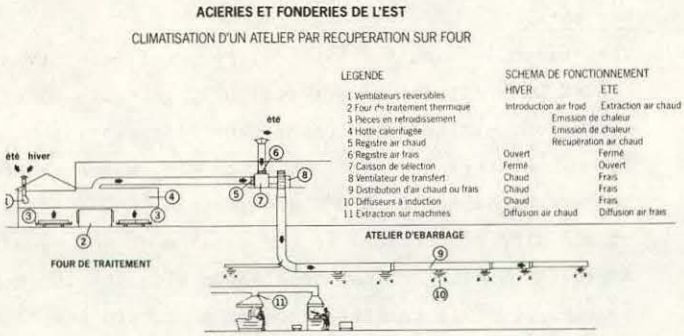
Investment ⟶ 2,300,000 FF
Saving ⟶ 720,000 FF/year
R.O.I. ⟶ 3,2 years



11th example : The heat of the parts during cooling down may be used to heat up premises

The workshop to be heated up contains an annealing-furnace which generates a continuous heat, partly from radiations of the walls of the furnace and ancillary equipment, and partly from the heat given by the metal parts being cooled down. The principle of operation performed by SOCIETE ACIERIE & FONDERIE de l'EST in Saint-Suzanne consists in collecting these calories in a closed hood which is heat-insulated, then, after mixing with the external air, blowing inside a duct and distributing at the working stations. A control device is provided to have a suitable temperature which is constant at the working stations, from this source of heat which has periodical variations.

Investment ⟶ 211,000 FF
Saving ⟶ 100,000 FF/year
R.O.I. ⟶ 2,1 years

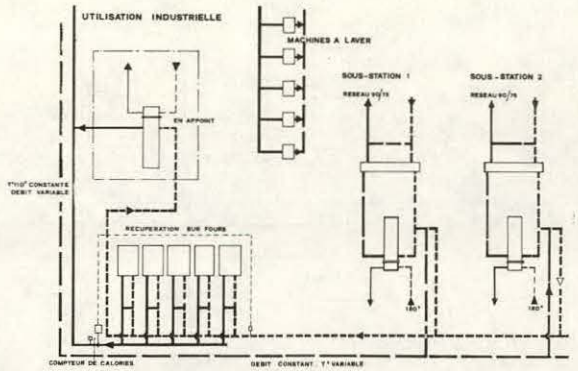


12th example : Recovery of fumes of heat treatment furnaces for the supply of hot water to washing machines and for a heating network

Eight tunnel type gas furnaces operating continuously for heat treatment of metal parts in the CITROEN plant in Metz have been equipped with devices for the recovery of heat from the fumes. The heat recovered feeds, via a network of pressurized water, washing machines in the same workshop.

The rest of the heat available on the exchangers is fully absorbed by the heating system of the plant. With such recovery, the overall efficiency of the furnacesis increased from 28% to 63%.

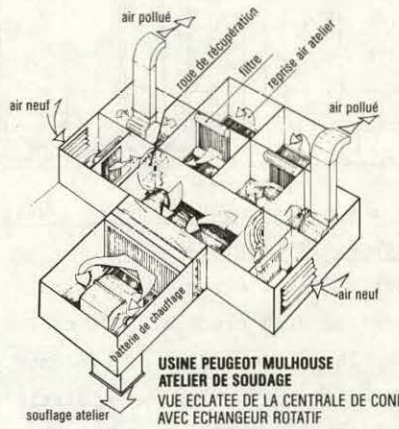
Investment ⟶ 1,500,000 FF
Saving ⟶ 580,000 FF/year
R.O.I. ⟶ 2,6 years



13th example : It is also possible to utilize the calories contained in the air removed from premises

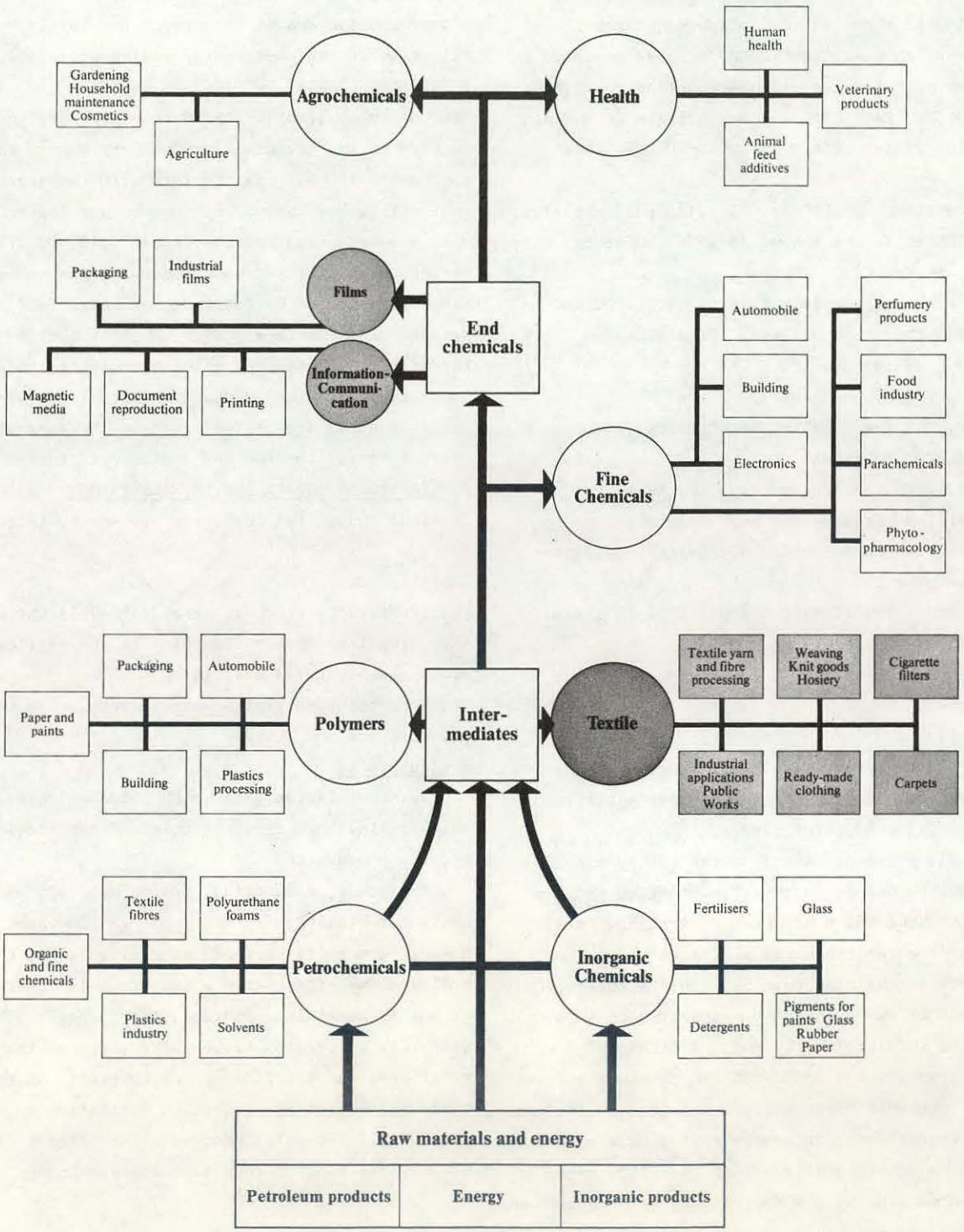
It consists in together heating up and renewing the air from a sheet metal workshop in the plant of PEUGEOT in Mulhouse by recovering the calories from the air removed. The recovery device, with an efficiency of 75%, consists in a metal wheel which alternately heats up on parts of its periphery when in contact with the air removed from the workshop, then cools down by giving back its heat to the external air. Then we just have to bring added calories using a conventional battery supplied with water overheated in a fuel oil boiler. This wheel recovery provides a particularly reliable operation due to its sturdiness and to its resistance to fouling of such an equipment.

Investment ⟶ 1,290,000 FF
Saving ⟶ 240,000 FF/year
R.O.I. ⟶ 5,3 years



RHÔNE-POULENC

an industrial group with interdependent activities



HOW ENERGY IS USED RATIONALLY AT RHONE-POULENC

RHONE-POULENC'S ENERGY CONSUMPTION AND CONSERVATION PROGRAM

RHONE-POULENC is the leading French chemical group, ninth in the world in that field. It has 107.000 employees. Its activities cover every field of chemicals : fine chemicals, inorganic chemicals, petrochemicals, plastics, pharmaceuticals, crop protection as shown on the following chart.

In 1978 the RHONE-POULENC GROUP'S sales amounted to 25,500 MF with foreign sales accounting for 59%.

RHONE-POULENC facility in Great Britain is MAY and BAKER. The US subsidiary is RHONE-POULENC Inc.

In France RHONE-POULENC has 75 principal factories.

RHONE-POULENC is the second largest industrial energy consumer in France.

In 1978 the energy consumption of RHONE-POULENC in France amounted at 4 Millions TOE divided in :

- 1,3 M. TOE for gas
- 1,4 M. TOE for fuel-oil
- 1,16 M. TOE for supplied electricity
- 0,14 M. TOE for coal

The total amount of energy expenses is around 1,500 Million Francs.

Therefore the RHONE-POULENC determination to save energy is great.

Efforts have been conducted since 1974 in three directions :

- energy management
- investment
- education

In 1978 these efforts resulted in energy savings in the amount of 350,000 TOE of the Group's usage compared to 1973 production levels.

To make all personnel aware of the energy problem RHONE-POULENC has produced an information program called ENERGECO which has been distributed to all the Group's establishements in France and abroad.

It has been translated into Spanish, Portugese, Greek and German by our subsidiary companies. It is now translated into English by MAY and BAKER.

This program enabled RHONE-POULENC to win the first prize in the 1978 "Save Energy" competition in France.

Efforts in research for energy saving have also been rewarded by an official award in the "1978 prize of Energy" organized by the Société Générale which honored two of our research workers for their work on a special burner called LEA.

In the present context of increasing energy cost and of energy scarcity one of the RHONE-POULENC's priority concerns is to use energy rationally.

The primary energy available at the inputs to our facilities : heavy fuel, coal, natural gas, must be transformed to become usable by our production processes.

Therefore, energy will be used rationally at the transformation and at the production levels by the selection of the most energy saving processes.

1. PRIMARY ENERGY

Most of our thermal installations were designed or adapted to the use of heavy fuel oil during the 1960s. So, nearly all our coal boilers were transformed to fuel oil irreversibly. Only one of our factories still uses a substantial amount ol coal (150,000 t/year).

During these last years, our natural gas consumption has increased to the detriment of heavy fuel oil because of the extensions to the distribution network, the ease of use and the elimination of pollution.

However, all the contracts for thermal use are interruptible so we are obliged to keep the apparatus and storage facilities for the replacement fuels.

2. TRANSFORMATION OF THE PRIMARY ENERGY

Chemical industrial processes use energy in two main forms :

- heat

  . essentially steam at pressure levels which can vary from I to 80 bar according to the application or the temperatures desired

  . heat transfer fluids when vessels under heavy pressure are not desired

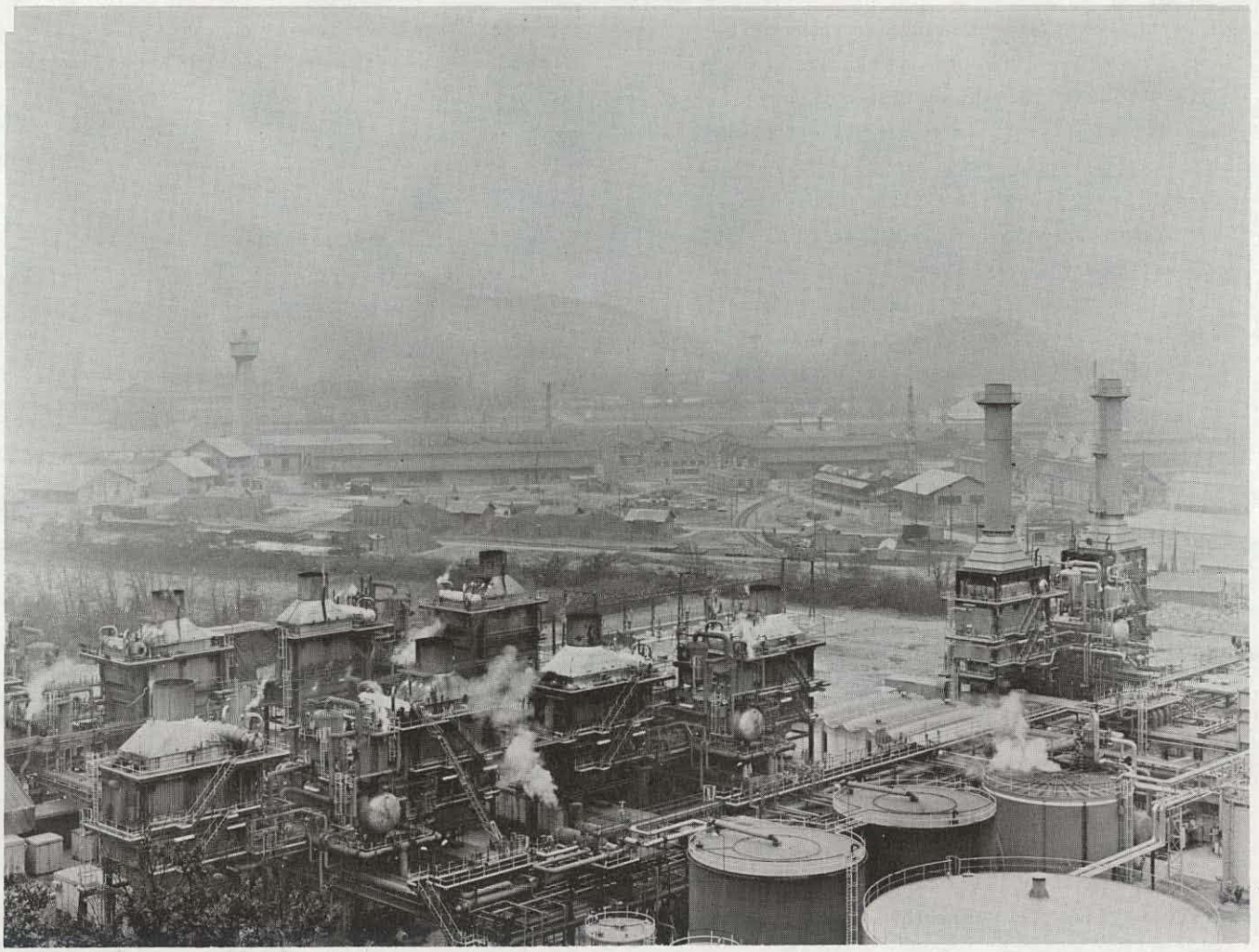
- electricity

  . for the electrolysis which produces chlorine and which drains more than one third of our total electricity consumption

  . for power, monitoring, remote control, exceptionally for heating.

Heat is generally produced at a given site, in a central heating plant, from which steam is distributed at one or several pressures. Unfortunately, the geographical dispersion of our sites, due to the historical development of our group, prevents us from centralizing our steam production facilities to optimize our overall potential. However, our largest factories use several hundred tons of steam per hour.

The PONT DE CLAIX's power plant - Ten gas turbines with heat recovery steam generators (sec § 2.3.)



To optimize the use of primary energy, for a long time we have had high pressure boilers and back pressure turbines. These turbines generally drive alternators producing electric current under these particularly reliable conditions, backing up the installations in case of disturbance on the outside electrical network which supplies the plant.

In certain cases, the turbines directly drive the process machines (compressor, pumps) since until now, this system has been considered as more reliable and easier to control. We shall see further on that other more advantageous methods are now possible.

Actually, all our boilers have economizers (preheating of the water by the smoke) and often an air reheater (on the smoke or on the residual hot fluids). Efficiency regularly reaches 91 to 92%.

We shall essentially develop the aspect of the production of heat and power and we shall indicate certain special and original methods implemented on certain sites.

We produce 30% of our overall electricity needs, essentially :

- by high pressure steam boilers and turbine-alternator (15%)
- by gas turbines (on a single site, 15%).

2.1. Example of a back pressure installation :

Belle-Etoile plant

The unit includes four boilers of 60 t/h, 80 bar, 480°C plus three turbine-alternators (2 x 5,5 MW + 1 x 9 MW) which supply the steam by draw off at 14 bar and by back pressure at 7 bar. The installation makes it possible to produce an average of 75 kWh/t of steam ; more precisely, it consumes 1.17 th/kWh in the form of fuel oil or natural gas.

According to the pressure levels and the degree of super-heating, the back pressure makes it possible to produce 50 to 120 kWh/t of steam. On certain sites where we have excess steam due to recovery on production processes, we use condensing turbines. When possible, we do the condensing with boiler make up water which provides advantageous overall efficiency.

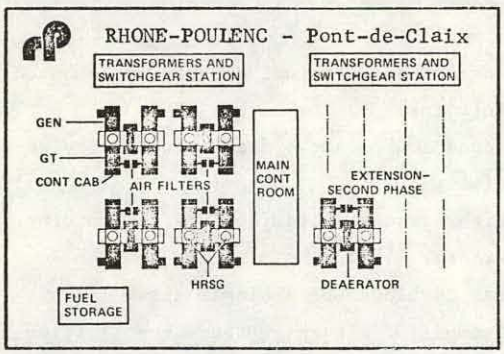
2.2. Remplacement of steam reducing valve by back pressure turbine : MAY and BAKER - Dagenham plant

The turbine was installed to replace a 6.8 bar to 0.35 bar reducing valve supplying steam to a deserator. It comprises a single stage turbine driving an induction generator. It cost £ 19,000 to install and during its first year operations produced electricity worth £ 14,000. In four years running maintenance has been minimal and no difficulties have been experienced with its operation.

2.3. Example of gas turbine installation :

Pont de Claix plant

When the electric current needs as related to the steam needs reach 300 to 400 kWh/t, it is possible to use gas turbines equipped with heat recovery boilers. We did this as early as ten years ago at Pont de Claix. We have eight GTs of 15 MW and two GTs of 23 MW equipped with heat recovery boilers without reheating. The real power is, therefore, 166 MW electric, and 480 t/h of steam, 30 bar, 280°C. The overall efficiency is about 78%, with one quarter of the energy consumed being transformed into electricity, half into steam, the last quarter lost.



RHONE-POULENC GT
OPERATING DATA

MODEL	MS 5000 LA	MS-5000 N
RATING	16 200 KW	23 750 KW
FIRING TEMP	900 C	943 C
EXHAUST TEMP	500 C	482 C
AIR FLOW	343 TONS/HR	419 TONS/HR
STEAM FLOW	46.5 TONS/HR	52.6 TONS/HR
STEAM PRESSURE	30 BARS	30 BARS
STEAM TEMP	275 C	275 C
FEED WATER TEMP	216 C	216 C

- Fuel : In the beginning, this installation operated only on a heavy fuel oil especially developed for this installation with the manufacturer and the oi companies. This fuel made it possible to reach nearly the same performance as with natural gas. Our consumption has gone beyond 1000 t/day.

FUEL CHEMICAL CHARACTERISTICS

	LESS THAN	
VANADIUM	0.5	PPM
SODIUM	1.0	PPM
MAGNESIUM	0.5	PPM
CALCIUM	1.0	PPM
POTASSIUM	0.5	PPM
LEAD	0.5	PPM
SULFUR	1.7	%
Na + K	1.0	PPM

Since 1976, the arrival of natural gas in the Grenoble region has made it possible for us to convert six machines, thus reducing the operation contraints ; nevertheless, it is always possible to go back to liquid fuel in case of unavailability of gas.

- Operating reliability : The average availability for each turbine is 92% on fuel oil and 94% on gas. This performance has been reached due to rigorous maintenance of the equipment by a particularly well-trained team. The number of machines installed justified this policy thus ensuring efficient use of operating and maintenance personnel, as well as good turnover of the spare parts inventory.

OPERATING EXPERIENCE DATA
DEC. 1978

TOTAL GENERATION	—	8,343,599 MWH
OPERATION	—	534,599 HRS
STARTS	—	2,150
AVAILABILITY	—	92,88 %
ENERGY SAVING	—	750,000 TeP

- Energy saving : In December 1978, the total energy saving since the start of the unit came to 750.000 TOE. The specific consumption is 3,650 BTU/kWh.

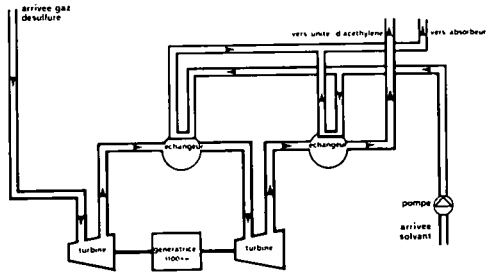
2.4. Production of motive power by expansion of natural gas : Pardies plant

The natural gas requirements are 25,000 m3/h ; the gas comes in at 28 bar and is used by the shop at 3 bar. The expansion energy is recovered by a two-stage centrifigal turbine which drives an induction generator : the power at the terminals is about 900 kW.

The gas escaping at -35°C from each of the stages is reheated in an exchanger by a process solvent, which thus improves its absorptive power and provides complementary energy savings (equivalent of 3 t/h of steam), within the process itself.

This installation saves 3,300 TOE/year.

The pay back time of such an installation is approximately three years assuming that the by-product frigories are totally used.



SCHEMA DE PRINCIPE DE L'INSTALLATION

2.5. Gas turbines coupled to dryers : Bordeaux Plant dryers

Many pellet or powder dryers operate with a hot air generator. In order to limit the temperature at which the hot gases come into the dryer, the combustion is made with a considerable excess air.

This operation can be advantageously performed with a gas turbine which drives an electric generator. The temperature of the exhaust gases is approximately 450-500°C, which is often quite appropriate for direct drying.

Such an installation was constructed in one of our fertilizer plants with a 500 kW operating on natural gas.

2.6. Constraints and prospects for combined production

The evolution of energy costs has made it necessary for us to review all our processes for any possible improvements which would save or recover energy : this has generally resulted in substantial reduction in our steam requirements, but has had much less effect on our electricity consumption. Consequently, there has been an inferior use of our self-production capabilities.

As to the future of combined production in France, it seems to us that it is jeopardized because of the expected evolution of the costs of primary energy and the weight of the investment on the other hand.

The efforts now going into nuclear power plant construction should provide for our basic electricity needs and advantageous price which should increase more slowly than fossil fuel prices.

Moreover, the financial situation for the chemical industry in France obliges to concentrate its investments in very specific areas to meet the demand of the main markets. Under these conditions, new installations of electricity self-production are limited to cover the vital requirements for facilities security and personnel safety.

3. USE OF ENERGY IN THE SHOPS

3.1. Steam

We are only talking about the consuming equipment itself (boilers, reactors, various exchangers) to draw attention to the adaptation of the type of steam to the needs, avoiding the use of superheated steam in the exchangers and limiting the pressure to the strict requirements.

Steam distribution

- The necessity of lagging is evident. Nevertheless, the insulation thickenesses must be re-adapted to the new energy costs, anticipating them when possible.
- The on-site steam distribution networks are often multiple, complex and poorly adapted due to past extensions as our needs developed. Experience has shown us that it is sometimes profitable to redesign and rebuild the system, eliminating certain lines. This requires an investigation to determine the real needs of the users. In this way, the turbine steam flow could be increased so as to make the operation more profitable.
- Recovery of condensates is also an important point which was often neglected in the past. There are now pressurized recovery methods which avoid the loss of revaporized steam by eliminating the expansion of the condensates. This has been implemented many times and the return on investment has generally been completed in from 1 to 2 years.

3.2. Electricity

Other than electrolysis, electric power is essentially consumed by drive motors.

- High efficiency motors

For several years now, the manufacturers have been proposing, in addition to the standard motors which were probably economically optimal before 1974, high efficiency motors which are better adapted to present conditions.

Take for example, the case of a motor of about 50 kW :

- The high efficiency motor costs 35% more than the standard motor. The efficiency gain is 3 to 4%. Since an electric motor annually consumes power equivalent to 10 times its price, for 8,000 hours of service,

the annual savings is quite close to the extra costs of the high efficiency motor.

- Variable speed motors

Variable speed motor technique has been developed over these last years and is being implemented more and more in the case of machines with a wide range of operating speeds. This makes it possible to avoid direct current motors and flow control by throttling. Profitability essentially depends on the operation of such machines.

For example : Ventilation units of 2 MW may become profitable in less than 12 months if the average load is less than 90%.

Moreover, steam turbines are not exceptionally efficient because of their often limited size ; it is preferable to use variable speed electric motors and to install a single back pressure turbine.

4. OPTIMUM USE OF ENERGY IN PRODUCTION PROCESSES

4.1. Improvement of chemical processes for energy recovery

Overall, about fifty operations of this type have been implemented or are being implemented, representing a savings of 86,000 TOE per year.

1st example : Recovery on the exhaust fumes from a sulfuric acid concentrating furnace to produce steam (implemented)

Annual savings : 3,200 TOE.

2nd example : Recompression of steam on a cyclyhexane/cyclohexanol separation column (planning stage)

Annual savings : 5,800 TOE.

4.2. Process improvement due to new technologies

We shall mention, as an example, the improvements implemented by RHONE-POULENC in the production of electrolytic chlorine.

Traditionally a major chlorine producer (52% of French production), RHONE-POULENC has mercury cells and diaphragm cells.

Installing metal anodes in the cells has brought savings of about 400 to 550 kWh/t.

4.3. Getting value from production residues

1st example : Furnace for incinerating organic residues on the Chalampé plant with steam production (being implemented)

Savings : 17,400 TOE per year

2nd example : Processing of polyester textile scrap for production of BIDIM

Savings : 4,340 TOE per year

3nd example : Burning of heavy chlorinated residues (from the production of chlorinated solvants) with recovery of the hydrochloric acid at 33% and steam production.

Savings : 1,600 TOE per year + 24,000 tons of HCL.

In this process, we also use an original burner designed by RHONE-POULENC, designated the LEA, which has many other applications as well.

4.4. New processes

In the long term, whenever possible, the overhaul of a process provides substantial energy savings.

These examples illustrate this :

1st example : Improvement of the energy content in the nylon line :

Due to the production of adiponitrile using butadiene with the DUPONT process, since adipic acid becomes the only basic product of this line produced from cyclohexane according to an RP Oxidation process, the energy content has been improved by more than 15%.

2nd example : Improvement of the energy content in acetic acid :

Due to the production of acetic acid according to the MONSANTO process, that is using the CO according to the conventional ex. acetaldehyde process, the energy content in the acetic acid produced on the Pardies site will be reduced by 33%.

3rd example : Improvement of the energy content in the methionine line :

RP has traditionally held a strong position worldwide in methionine, a synthetic product used for poultry raising.

An improvement in the use of propylene oxidation which is the basic of the methionine synthesis, as well as the initiation of profitable industrial use of an inevitable by-product, is going to provide a gain of 10,000 TOE per year.

5. DEVELOPING NEW VECTOR PRODUCTS FOR ENERGY SAVINGS

This is also one of the aspects of RP's activities in this field. Here are two examples :

1st example : Storage of energy in heat transfer fluid

RP works particulary in research to design couple of organic fluids and good thermal inert solid in temperature ranges reaching 350°C. This especially concerns solar energy and possibly the daily storage of nuclear energy in electric power plants.

2nd example : Thermodynamic fluids

Developing thermodynamic fluids (flugenes) which are more advantageous than water for transforming heat energy which is recoverable at low level in motive power.

RP is particularly working on Flugene 114 which has good compatibility with compressor lubrication oil, and no degradation at temperatures of from 80 to 120°C.

6. ENERGY SAVINGS LINKED TO BUILDINGS

6.1. Remote control of heating systems at MAY and BAKER

The Dagenham site comprises an 80 acre complex containing a variety of buildings supplied with heat from a central boiler plant.

Time clock control of the heating systems was difficult due to varying occupancy times and a dedicated site system for central control-very expensive.

A new 1200 line PABX telephone exchange was recently installed which has the facility for remote switching using a normal telephone hand set. Up to 40 heating plants will be switched from the central boiler plant using existing boiler house personnel and the site telephone cabling system.

The system is very flexible and easily overcomes difficulties with changing periods of occupancy due to overtime, bank holidays, summer time, etc.

It is anticipated that when the system is fully operational it will reduce the consumption of fuel on the site by 10%.

6.2. Heat pump at RHONE-POULENC GRAPHIC Avranches

This plant produces metal plates for the printing industry. The chrome plating of the plates by electrolysis requires that the baths be cooled. An installation for regenerating these low level calories has made it possible for us to profitably use them for heating the nearby shops.

Annual savings : 160 TOE.

6.3. Heat recovery and heat pumps at RHONE-POULENC's Headquarters in Courbevoie

The dimensions of the Headquarters made it possible for us to consider air conditioning approaches which were both original and energy saving. Moreover, the high rise building classification made it necessary to use completely safe methods.

We choose an "all electric" installation using heat pumps and a calorie storage for an advantageous exploitation of the electricity contract. A regeneration circuit on the light fixtures provides a cold source for the heat pumps. A back-up electric boiler, when necessary, raises the storage temperature level during cool periods (5°C).

In hot periods, the heat is removed by air cooled heat exchangers.

The average annual, consumption is 14,000,000 kWh, that is 300 kWh/m 2 air conditioned. The subscribed power is 3,800 kW.

CONCLUSION

French industry and RHONE-POULENC make great efforts to use energy in the most efficient way.

Thus, by the knowledge of the energy content of their products and by their constant stress on energy savings, they contribute to today's world's mandatory task for best energy recovery.

ENERGY USE MANAGEMENT: ONE COMPANY'S STORY

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ABSTRACT

Rapidly increasing energy prices, as well as increasingly uncertain supplies, have caused some fundamental readjustments in the ways industrial corporations manage their energy use. Most manufacturing facilities and energy management procedures were designed at a time when energy and raw material costs were not significant contributors to plant and product costs. In order to stay competitive in the post-1973 environment, U. S. industry has had to make basic changes in those facilities and procedures.

At Union Carbide, the initial response was to establish energy use and planning programs, centralize energy planning, and implement energy conservation programs. Second, we began a period of reexamining and revising those mechanisms, and of fully integrating energy use management into our basic operations and business planning. That process still continues today. Finally, we expect that, as energy takes a firm position as one of our most prominent operating factors -- along with labor, materials costs and capital availability -- we will need to rely less on formal structures and programs to manage it. It will become another significant responsibility of all line management, along with environmental concerns, OSHA, toxic substances control, waste disposal, and other new operating priorities.

Introduction

The image of a dinosaur -- a slow-moving, cold-blooded creature with a huge body and a not-so-huge mind -- has been applied to just about every big organization you can name. Government agencies and large corporations both face chronic charges that they resemble the big reptiles not only in size, but also in their failure to adapt rapidly to changes in their environment.

The story I want to bring to you today is that of a large corporation -- my company, Union Carbide -- and its attempts to deal with an even larger problem: the energy crisis. Along the way I hope to give you some examples of how a seemingly threatening change in the business environment can actually bring about a change for the better in the management of a large organization -- leading it to avoid the fate of the brontosaurus.

UCC Background

Why is energy such an important factor in our business planning?

Because we use a lot of it. While it's always difficult to make calculations at this scale, we figure Union Carbide uses pretty close to half of one percent of all the energy consumed in the U.S.

And we spend a lot on it. Last year we paid out for energy materials 25¢ on every sales dollar we made -- our total energy bill was $2 billion.

Pre-Embargo Environment

As we all know, October 1973 and the Arab oil embargo marked the beginning of the end of the era of cheap energy in this country. Before the OPEC cartel began its aggressive pricing policies and its supply constraints, surpluses of oil and natural gas were the norm, and energy was cheap. For the most part, Union Carbide bought the petroleum and coal energy it needed on the spot market, because we could generally expect to get a lower price through such purchases than that available through long-term contracts. And, as in most U.S. industry, many of our manufacturing facilities were designed at a time when fuel and feedstock costs were not a truly significant contributor to plant and product costs.

All of this is not to say there were not organized efforts to conserve energy before the embargo. Our Chemicals and Plastics division set up a formal conservation program as early as 1971. Also, signals in the marketplace were beginning to warn of much higher prices in oil and natural gas before the OPEC actions took place, and we were not unaware of these trends.

However, I think that, in general, the sudden turnaround in price and supply in 1973 caught us -- as well as the rest of the nation -- off guard. Suddenly we were looking at greatly increased costs and possible supply problems. And since we use petroleum energy as a raw material as well as fuel, our industry could expect to be among those most severely affected by the changing energy situation.

We've gone through three stages in responding to the 1973 oil crisis. First, we, like most Americans, scrambled for short-term solutions that would carry us until the energy market adjusted to the new ground rules imposed by OPEC. We looked for, and began to implement, some fundamental management mechanisms to help Union Carbide make that same adjustment and continue functioning as a strong business. Second we began a period of reexamining and revising those mechanisms, and of fully integrating energy use management into our basic operations and business planning. That process still continues today. Finally, we expect that, as energy takes a firm position as one of our most prominent operating factors -- along with labor, materials costs and capital availability -- we will need to rely less on formal structures and programs to manage it. It will become another significant responsibility of all line management, along with environmental concerns, OSHA, toxic substances control, waste disposal, and other new operating priorities.

Stage One: Coping with the Crisis

As soon as the oil crisis broke in 1973, our top management began addressing its implications for the corporation. They established new programs and created new organizations within the company to deal with the situation. Practically overnight, we went from having no centralized energy planning to a stage where 20-year master plans seemed necessary.

Planning teams went to work, and in some cases engaged in a form of planning overkill. In spite of our best intentions, some of our early planning ideas turned out to be impractical and, sometimes, unnecessary.

Just before the embargo crisis, Carbide's president had appointed an Energy and Feedstock Policy Council to provide overall direction and emphasis to corporate activities in what would soon become a vitally important area. The Council was primarily made up of a few senior corporate officers. There was, thus, a commitment and direction from the highest level.

In addition to this Policy Council, a corporate-wide Energy and Feedstock Planning Team was formed, made up of corporate, division, and international managers responsible for the energy-sensitive activities in each group.

Supporting the Planning Team was a Energy and Feedstock Planning Staff, charged with initiating studies, making recommendations, and generally serving as a resource of analysis and expertise to the Planning Team.

The purpose of this effort was to coordinate corporate-wide planning for energy and feedstocks. But, even more important, it was to establish effective long-range programs and strategies to meet the corporation's continuing needs in this area.

A "corporate energy action plan" was developed which articulated these goals and priorities:

- A formal 20-year business planning process was initiated, which undertook to forecast energy supply availability, prices, and Union Carbide's requirements; and to plan for the procurement of all our energy and feedstock materials on a worldwide basis. These 20-year plans were prepared annually, and forced our business planners to build into their thinking the anticipation of future high energy prices and changing patterns of availability of energy and feedstock materials.

- Energy purchasing was consolidated into a new group to procure all of the energy and feedstock materials. It developed a high level of expertise in both current and future availability and energy pricing. This group prepared short-range procurement plans as well as 20-year plans, to support the business planners' 20-year plans.

- Energy conservation was pinpointed as one of the most important programs recommended for immediate implementation. In early 1974, a formal corporate energy conservative program was initiated. This is a corporate program -- that is, for us, a world-wide program. We practice energy conservation as a line organization activity -- as something that can and should be built into every employee's job. It's something that cannot be effectively managed by a corporate staff group. However, since it is a corporate program, we do insist on uniform scorekeeping and reporting.

Stage Two: The Transition from Crisis to Convention

While all this I've described was taking place, the first oil crisis faded into history. In turn it was followed by a natural gas shortage that became a supply glut; a sharp turn toward coal that was stopped dead in its tracks by stringent environmental standards, coal miner strikes, and a host of other factors; the development of a de facto moratorium on what once seemed to be our most promising power source -- nuclear energy; and huge oil price increases that have begun to make economic some of the more remote energy options, like synfuels, biomass and solar energy.

My point is that the energy picture has changed several times since the 1973-74 crisis. We expect it will continue to shift around in the future and our corporate planning has to recognize this. Each year since we began forecasting corporate energy needs, our actual use has been well under the consumption levels we'd anticipated, and we've constantly been revising our future forecasts downward.

Part of the reason for this is the success we've had in meeting our conservation goals. In 1975 we set a 1980 goal for BTU/pound savings of 15 percent compared to 1972. We long ago passed this goal -- we're now over 20 percent. And we've set a new corporate goal: by 1985 we will have reduced our energy consumption per pound of product by 30 percent, compared with the 1972 base year.

Meanwhile, the Energy Policy Council's responsibilities were turned over to an Energy Policy Department, incorporating the planning staff. And the Planning Team became mainly a communications conduit between the Policy Department and the individual divisions.

Much of our attention has shifted to external affairs -- specifically government energy legislation and regulation, and energy supply forecasting. Here, the Energy Policy Department works closely with the corporate government relations and communications departments. And, we've responded well in both areas. The success

of conservation programs throughout industry has helped us avoid costly and restrictive government regulations for energy conservation. And during the two post-embargo years when the U.S. actually experienced a natural gas shortage, Union Carbide was virtually unaffected because our analyses had told us to expect shortfalls, and we planned accordingly.

Internally, the conservation message has been incorporated into a wide range of communications with employees at all levels. Our quarterly BTU per pound savings index, based on reporting by plants and divisions, is reported to top management. Major conservation milestones are communicated in corporate and plant periodicals. Virtually every Carbide facility in the U.S. has a special way of highlighting conservation for its employees.

Internally, the greatest challenge has been getting everyone in the company to think differently about energy. A successful conservation program must have more than a top-level commitment. All employees must make saving energy as much a part of their full-time work as using energy used to be.

In this sense, our whole effort has been a matter of communication and persuasion. And this is as true today as it was six years ago. Thanks to energy use reporting methods that help us pinpoint energy efficiency gains and losses, our managers now have better tools to help them monitor the conservation performance of individual processes and facilities. Where we've noticed losses, we've found that they are most often the result of laxity by the employees in using the conservation methods already in place.

Most of the internal reorganization necessary to plan and carry out a company-wide energy conservation program was accomplished at Union Carbide fairly early on. After the mechanisms were in place, the challenge became not so much providing management tools as making sure people used them.

Stage Three: As Natural as Breathing

At Union Carbide we've reached the point where the present and future high prices of energy, and the uncertainties in its supply, are recognized and understood by corporate and divisional managements. This awareness is built into their current decisions and long range business planning. The Policy Council and the Planning Team have been phased out because they are no longer needed, and the Policy Department's primary role is now to formulate corporate policy and actions regarding energy and feedstock legislation and regulation. As energy conservation manager for Union Carbide, my goal is to put myself out of a job. If energy prices continue to rise as we expect they will, that won't be difficult, because eventually energy costs alone would provide all the awareness and the incentive we need to conserve. Using energy efficiently would become as natural as breathing.

For the time being, though, we do face a substantial barrier to our continued investment in conservation projects. That is, the decision to invest labor, planning effort and capital in energy conservation has to compete in the corporate arena with a whole host of other business priorities.

For instance, some of our operations are not energy-intensive -- the energy they use may be only a relatively small cost factor. For them, conservation may have a less critical importance, compared to, say, containing labor costs. This is not to suggest conservation is not important -- just that it may sometimes come in behind other business priorities.

I'll give you another example of the conservation priority dilemma. Union Carbide now figures it can, with a two year payback, invest $15,000-$20,000 in conservation projects for each barrel of oil equivalent saved daily and these investments most often require little or no operating costs. That's considerably less than current investment levels required to get the same amount of energy from new oil or gas discoveries (they now cost around $21,000 for a barrel per day), shale oil (requires about a $30,000 investment), or coal liquefaction (one current process would need a $55,000 investment for a daily barrel of oil equivalent). These projects will have very large production costs associated with them so we can consider conservation as a pretty inexpensive way of, in effect, producing energy.

Unfortunately, our supplies of capital are finite, as they are for most corporations, and there are many competing demands for capital investment other than conservation. While Union Carbide has achieved its energy efficiency improvement goals to date, each succeeding increment of energy efficiency improvement will require a greater investment -- of commitment, labor and capital.

The organizational changes we've already made in both the corporation and the divisions will continue to support our commitment to an increasing level of energy use management. But putting limited capital into energy-saving investments, attractive as they may appear, is not always possible. For this reason, Union Carbide is actively endorsing legislation that would grant federal financial incentives for industrial energy conservation investment. Such a national policy would help us, and many other large energy users, move into a new level of commitment to energy conservation. And this is cost effective to the nation in reducing our dependence on imported oil with its supply security and financial problems.

The current thinking about energy conservation is that it is tantamount to energy production -- a barrel saved is a barrel the nation doesn't have to import. Geologists tell us petroleum energy came from dinosaurs -- to those who persist in calling us a dinosaur, I say it's we who will, through energy use management, help "produce" energy in the future.

ENERGY RESPONSIBILITY ACCOUNTING
AN ENERGY-CONSERVATION TOOL FOR INDUSTRIAL FACILITIES

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ABSTRACT

As energy costs continue to rise faster than the rate of inflation, industrial energy management becomes a more important issue in the control of manufacturing costs. Energy Responsibility Accounting (ERA) is a tool which improves management's control of energy through accurate measurement of energy usage and costs by plant burden centers. The concept of responsibility accounting involves the continuous flow of information throughout an organization for the purposes of planning and cost control. In the past, responsibility accounting has been used primarily to control labor costs, to reduce material waste, and to contain the cost of supplies. ERA extends factory responsibility accounting systems to include energy. With ERA, management will know who is making an effort to conserve energy, how a new process affects energy usage, where additional emphasis on conservation may be needed and how much energy is being saved.

Topics To Be Discussed

The topics which will be covered in this paper include a summary of GM's conservation performance, ERA philosopy, ERA implementation and concepts for performance reporting, and the benefits of Energy Responsibility Accounting.

The formal implementation of ERA within GM began in 1977 with the publication of a manual which described the steps necessary to implement ERA in a plant. Although this was the first action to spread the concept throughout GM, it had existed in a few plants for some years. For example, in 1969, the AC Spark Plug Division plant in Flint, Michigan, implemented ERA in its Plant Engineering Department and achieved a 10% energy reduction the first year.

In 1975, GM began ERA on a corporate basis with the EMS-100 Energy Conservation Performance Report. The monthly report is submitted to the Energy Management Section by each plant. It measures the plant's conservation efforts compared with the same year-ago period. The report compiled from this information is used by Plant Managers, Divisional General Managers, and Group Executives to compare the performance of similar plants and divisions. Such performance is a small, but important criterion for judging a manager's overall performance. It also provides the factual justification needed to allocate manpower and dollars for cost effective conservation activities.

GM Conservation Performance

General Motors' energy conservation performance results clearly indicate the value of an aggressive conservation program which includes energy accountability. In 1979, GM used 6.6% less energy than in 1972. This is a major accomplishment when considering that in 1979 our North American operations produced nearly 1.1 million or 17.6% more vehicles, increased manufacturing space by 38.6 million square feet or 19.7%, and increased employment by 79,000 or 13.7%. The savings due to the conservation program are 23.9%.

Our 1979 North American energy bill was $977 million. Without a continuing conservation program the bill would have been $306 million higher. As you can see, energy conservation can be a valuable cost control tool to help maintain a competitive edge in the marketplace.

Let's look at how ERA will motivate managers to save energy and thus reduce energy costs.

ERA Philosophy

Since ERA is a management tool, it does not save energy as such. However, the results obtained from effectively using ERA are measurable. ERA will motivate managers to place greater emphasis on reducing energy usage and costs because these same managers will receive the direct benefits of their efforts on the plant report. As in any organization, management teams set their priorities based on where their performance is directly measured. By adding energy costs to their plant report, improved energy efficiency will receive greater attention by all users. For example, an added effort to monitor and implement effective shutdown of equipment is readily justified - even at some added labor cost to the manager - if the energy savings obtained exceeds the labor cost involved and is shown as a savings on the manager's plant report.

Some process changes may involve the risk of reduced efficiency. A production manager will be more willing to take the risks involved in a process change to save energy if the resultant energy savings appear on his plant report. If a manager changes from a hot water washing process to cold water wash, any change in production efficiency could be balanced against a reduction in energy usage. Before ERA, the production manager would be asked to take these risks without receiving the resultant benefits on his "report card."

You may be asking yourself, "All of this sounds good, but what level of savings can my plant achieve by implementing ERA." Although ERA is in its infancy in GM, we believe that a plant can improve its energy efficiency by 5-10%. These savings are reasonable and can be easily justified.

ERA Implementation

Now that we know why ERA should be implemented in manufacturing plants, let's look at how it can be implemented. The three general steps involved are:

1. Design and install an accurate energy measurement system through metering of utilities by burden center.

2. Formulate an energy budget based upon measured energy usage.

3. Publish energy performance reports.

1. Energy Measurement System

Detailed analysis of your plant's existing utility distribution systems is required, since that analysis forms the basis for decisions which will be made during the implementation of ERA. Up-to-date as-built drawings of the utility distribution systems are not usually available, due to plant expansion projects and changes to processes within the plant. Thus, the services of plant engineering personnel or an outside engineering firm are required to provide these drawings.

At the same time the utility distribution systems are being analyzed, cost center boundaries can be determined. A layout of cost centers within the plant can usually be obtained from the Industrial Engineering Department.

Since metering costs increase as the plant is divided into smaller segments, a balance must be achieved between the number of cost centers metered and the potential energy cost savings. In any case, certain isolated energy intensive processes such as heat treating should be identified.

When the configuration of existing utility systems and cost centers is known, utility distribution systems can be modified and meter locations selected in order to segregate cost center energy usage.

The next step in the process is to select the appropriate meters and data collection system to suit your application. This is critical since the data collected by the system forms the basis for performance reports. Most utility distribution systems in a manufacturing plant are designed to accommodate maximum operating demands plus some facility expansion. The original meters are usually designed to operate at these maximum conditions. Some GM plants have found that their normal energy usage was below the range in which their meters were designed to operate. This operating range is referred to as the turndown ratio and is an important consideration to ensure accurate metering.

When selecting a flow meter for fluids, consideration must be given to the following:

- Type of fluid being measured -- natural gas, steam, compressed air and water -- each have specific metering requirements.
- Operating pressures -- fluids should be measured at as high a pressure as possible to improve accuracy and reduce meter size.
- Maximum flow requirements to avoid oversizing of meters.

- Turndown ratio (the ratio of the maximum flow rate to the minimum flow rate to be accurately measured).
- Accuracy - initial and sustained accuracy must be maintained for a credible energy accounting system. Accuracy should be specified as percent of actual flow and not percent of full range to ensure good measurement.
- Economic considerations - first cost versus life cycle cost.

These are the basic criteria for selecting meters. Many articles have been written for trade journals regarding meter selection and should be used when designing your systems. The state of the art of metering is changing with industry's demand for accurate measurement. Plant engineers should work closely with local metering representatives to ensure the purchase of an accurate and reliable metering system.

A wide range of options for collecting data from meter outputs is available. Meters can be read manually, they can be read by a mini-computer which interfaces with a large data processing system, or by any other degree of sophistication within that range. Care must be taken to ensure that proper metering interfaces are purchased to attain a good fit between the meters and computer systems. The design and installation of an accurate energy measurement system is essential for ERA since it forms the basis from which management performance is measured.

2. Formulation Of The Energy Budget

The energy budget is the reference point against which performance is measured. The basis for the budget should be simple, easily understood by production personnel, accurate, timely and cost effective. Ideally, the energy budget reflects the energy requirements for a given set of parameters such as level of production, outdoor temperature, and a facility utilization factor. One approach which could be considered for developing the energy budget is the statistical model.

Statistical Energy Model

The statistical energy model relies upon historical energy usage data. The historical data will show that for a given set of parameters, a specific amount of energy was utilized, but it does not show how efficiently the energy was used. For example, referring to the data in Table I for 1976, given a production level of 600 units, a facility size of 150,000 square feet, and 6,750 degree days, 1,000 units of energy were used. If in 1980 the same number of units will be produced in the same size facility with identical weather conditions, the predicted energy usage would be 1,000 units.

Table 1	1976	1977	1978
Total Energy	1,000	1,100	1,050
Production	600	650	650
Facility Sq. Ft.	150,000	150,000	170,000
°Days	6,750	6,800	6,800

If 950 units of energy were used, the difference is due to conservation measures.

A simplistic model of energy usage can be developed from this basic data. The energy in a facility may be divided into two components, namely: nonproductive energy and productive energy. Nonproductive energy is that energy which does not vary with production volume such as building heating and lighting. Productive energy is the energy expended during production. If the nonproductive energy is nonvariable with production and it is found that the productive energy is directly variable with production, a forecast of energy usage can be made.

Example 1

A forecast of energy usage is to be made for the 1979 budget. Given the historical data from Table I, the fact that nonproductive energy is equal to 400 units, and the 1979 production will be 750, energy usage is calculated as follows:

TOTAL ENERGY = NON-PRODUCTIVE ENERGY + PRODUCTIVE ENERGY

NON-PRODUCTIVE ENERGY = 400

$$\text{1979 PRODUCTIVE ENERGY} = \text{1978 PRODUCTIVE ENERGY} \times \frac{\text{1979 PROD.}}{\text{1978 PROD.}}$$

1978 PRODUCTIVE ENERGY = 1978 TOTAL ENERGY - NON-PROD. ENERGY

= 1050 - 400 = 650

1979 PRODUCTIVE ENERGY = (650)(750/650) = 750

THUS THE 1979 ENERGY BUDGET = 400 + 750 = 1,150 UNITS

Conservation efforts can now be measured by comparing the 1979 energy budget to the actual energy used in 1979. Savings can be achieved in both the nonproductive and productive energy.

A more sophisticated approach to the statistical model is the use of linear regression analysis of historical energy usage. The constants generated for variables such as units produced, average outdoor temperature, square footage of floorspace, and utilization factor (days worked versus days available) would be used to calculate the energy budget. The mathematical formula could be as follows, but may vary when appropriate variables are determined for a specific facility.

Example

Y (Budgeted Energy)

= Constant (1) +

Constant (2) x Units Produced +

Constant (3) x Average Temp. +

Constant (4) x Floor Space +

Constant (5) x Utilization Factor

Constants (1) through (5) would be generated from the linear regression analysis. The figure used for each vehicle would be the actual number observed for the year. The budgeted energy would then be compared to the actual energy usage. The historical data used in the regression analysis may be distorted due to changes in production processes, OSHA regulations and EPA standards. Thus, the statistical energy model may not be as accurate as desired, but it is a good starting point for further analysis.

3. Energy Performance Reports

The publication of energy performance reports is the final step in the implementation of Energy Responsibility Accounting. The reports are used to compare a manager's performance against the budget. The reports should reflect energy usage in Btu's to show changes in energy consumed as well as in

dollars to show the importance of energy relative to direct labor, material, etc. Also, an energy conservation performance report showing percentage change in each department for the respective manager will motivate these managers to achieve even greater savings.

A variety of formats can be used for the performance reports. The format should be consistent with the established practice within your plant or corporation. A close working relationship should be established between the engineering and accounting departments to ensure compatibility of report format with the data available. An example of the report format follows.

EXAMPLE ENERGY REPORT

ENERGY CONSERVATION PERFORMANCE REPORT
PLANT #12

	ACTUAL ENERGY USAGE—MMBtu	BUDGET ENERGY USAGE—MMBtu	VARIANCE	PERCENT VARIANCE
DEPT. A	17,751	22,900	- 5,149	- 22.5%
DEPT. D	5,000	6,150	- 1,150	- 18.7%
DEPT. B	51,100	57,500	- 6,400	- 11.1%
DEPT. C	16,000	15,000	+ 1,000	+ 6.7%
TOTAL PLANT 12	89,851	101,550	-11,699	- 11.5%

The main criteria for any reporting system is that it is accurate, easily understood, cost effective, and is used by top management. Ideally, energy variances from the budget should be shown on the manufacturing expense report along with all other manufacturing costs. Energy is a cost which can be controlled and should be placed in the controllable portion of the plant report. Industry no longer can afford the luxury of allocating energy costs to production department on an "arbitrary" basis. The time and effort expended to establish and maintain an energy accounting system can be offset by energy cost savings when ERA is implemented to fit the environment in which each plant operates.

Concept For Increasing ERA's Value

As you can readily see, each plant would have many monthly performance reports involving budget calculations for each energy form (i.e., electricity, natural gas, steam, compressed air, and water). Associated with each energy form could be reports in applicable units such as Kwh, MMBtu, and dollars. Detailed costs, including peak demand, on peak usage and off peak usage could be also considered. An information explosion may occur in the next few years as more GM plants implement ERA. If each of GM's two hundred plants was divided into only four cost centers, over 1,000 reports would be compiled each month.

To make this extensive reporting cost effective, a computer program is in the planning process to handle the anticipated information load. The program would be designed to reduce the amount of engineering time needed to compile data from in-plant utility meters, powerhouse reports, utility bills, and production information. Since meter and cost center layouts are different at each plant location, the program must be designed for universal application. With a program designed for universal application, the energy coordinator at each plant could easily modify the plant description to reflect changes in department layout,

building additions or new plant sites. Access to the program and data base would be direct from the plant via a terminal allowing on-line data checks and modification.

A few GM plants have programs similar to this in operation, but these programs cannot yet be applied across the corporation. They are helping us learn about the intricacies of data compilation and also the time saving benefits of this computer application.

We believe that this program can accelerate ERA within GM.

Conclusion

We feel that a successful energy conservation program must have total involvement at all levels of management which centers around energy accountability.

Total involvement includes top management support, effective communication, motivation and enthusiasm. Designers, engineers and production personnel must work together to achieve difficult but attainable goals.

Although ERA is in its formative stages, we are convinced that improved management tools -- such as responsibility systems provide -- will result in improved cost control. Effective conservation centers around accountability -- knowing how much energy is being used, how much it costs, where it is being used, and who is using it wisely.

SAVING MONEY THROUGH EMPLOYEE MOTIVATION AND PARTICIPATION IN ENERGY CONSERVATION

WARD TOMLIN
GARRETT MANUFACTURING LIMITED
REXDALE, ONTARIO, CANADA

It is a particular pleasure for me to be here with you today to take part in the Texas Industrial Commission's Second Annual Industrial Energy Conference.

"Energy" being an essential, if not the most essential part of the economic and social development of all nations, requires the concentrated attention of all of us in its management. What's important to those of us here today is important to everyone, everywhere in the world.

We are pleased to have been asked to discuss with you employee motivation and participation in energy conservation, a topic sometimes neglected and all too infrequently discussed in relation to energy conservation. In our opinion however, it is a topic that is crucial to achieving and sustaining an on-going in-plant conservation program.

INTRODUCTION

This paper is concerned with the action taken since 1975 to conserve energy in the operational activities of Garrett Manufacturing Limited, the Canadian subsidiary of The Garrett Corporation, one of the Signal Companies.

For conference members not familiar with the electronics industry, I would like to take a moment to tell you a little about my company so that you may appreciate the relative importance we at Garrett, an aircraft electronic/electro-mechanical manufacturer, attach to energy conservation and energy management in a company where only a small amount of energy is used as a proportion of total cost of operating.

Garrett Manufacturing Limited (GML), is located in Rexdale, Ontario, Canada. GML has world charter responsibility for Temperature Control Systems having aerospace applications; Communication Systems, such as Downed Aircraft Locator/Personal Locator Beacons and Air Traffic Control equipment; Custom Hybrid Microcircuits for military and commercial use; and Electro-mechanical and Electronic Systems.

We also do major system and sub-contract manufacturing, and provide repair and overhaul and product support services. GML has also played a significant role in the Toronto Transit Commission's modernization of its rapid transit operations, providing regenerative chopper and electronic systems for 134 new subway cars and 200 light rail vehicles.

From a modest beginning as a Garrett sales office in 1952, Garrett Manufacturing Limited has grown steadily to a manufacturing organization of over 800 high technology personnel, working in six plants of more than 174,000 square feet, containing some of the most modern manufacturing and test equipment in North America.

At GML's head office and main plant at 255 Attwell Drive, laboratories, including environmental test facilities, development, production, qualification and reliability testing, are located along with the production shops for Temperature Control Systems, Electro-mechanical and Pneumatic Systems, Communication Systems, and Digital Systems.

Ground Transportation and Product Support activities are carried out in GML's Marmac facility, which is equipped to overhaul all Garrett Corporation Turbo Machinery and Gas Turbine equipment. It is also equipped to manufacture and test solid state Light Rail Propulsion equipment.

The Taber Road facility houses Purchasing, Plant Engineering, Record Services and Storage, Garrett Sales, and GML's Technical Training School.

The GML Microcircuit facility, containing over three million dollars worth of latest automatic equipment for production of thin and thick film hybrid circuits is located at 40 Voyager Court.

Our newest facility at 254 Attwell Drive in Rexdale has been completely renovated with "total energy balance" as the goal, to house our Design Engineering group and its associated laboratories and shops.

Six plants - six locations - six product lines - over 1,500 products - 800 people - and very labour intensive.

It will be appreciated from this introduction that while industry in Canada accounts for 40 percent of all the energy used in Canada, GML is not a heavy energy user. Unlike Canadian industry in general, Garrett Manufacturing spends less than 1.2 percent of its total operating costs on energy to operate its plants and offices and to produce its goods.

ORGANIZATION

The industry voluntary energy conservation task forces were first organized in Canada in 1975 and have grown to represent approximately 80 percent of Canada's industrial energy users. Their aim was to exchange information, increase awareness among members, set and report on targets and to serve as a focal point for Government/Industry discussions on energy.

This action on the part of the Government sparked GML's Vice President and General Manager to direct Garrett Canada's operating divisions to fully support the Government's measures to conserve energy. The manufacturing operations group responded immediately by setting up an energy conservation task force and met for the first time in July 1976.

The energy conservation task force at Garrett is made up of eleven members selected to provide a broad representation of both operational and support functions. Representatives on the task force from management are of sufficiently senior positions that the action required by the task force can be immediately and effectively implemented. At the same time, there is a good balance of technical and administrative expertise as well as individuals competent in the promotional aspects of the task force.

We believe that while the success of any far reaching conservation program is ultimately determined by the amount of involvement by the employee - the engineers the salesmen, the office personnel, the men and women who operate the machines, close the doors, turn off the lights - they look to the supervisory staff and management and the union leaders for their total commitment as measured by their involvement. Therefore, a word of caution! Prior to the design of an energy conservation or energy management program for your company, it is imperative to obtain the commitment of all top management and your unions to the goals of the program. Employees can tell when a conservation effort is just tokenism - and one give-away is quickly recognized as a lack of support from the top. If people are to be properly motivated to achieve savings, then management support requires more than someone giving the nod to a conservation program and assuming someone will "fit this little job" into an already busy schedule.

Management participation means a management that is committed to getting energy savings with the same interest and importance that it would place on extracting similar profits from increasing productivity.

I repeat - the key to establishing a successful energy conservation program is a genuine commitment from top management. Without this strong commitment and without the allocation of the needed resources, an energy conservation program will not work.

In our organization, responsibility for the program ultimately rests with the executive. Implementation however begins with the managers, so that the line supervisors are informed of the economic basis for conservation and their accountability for the energy consumed in their areas of control. They must also endeavour to establish a system in which the people who get the day to day work done participate in deciding upon and carrying out the energy conservation program.

Once management support has been enlisted, it is important to recruit a capable co-ordinator to form a plant energy conservation and management committee.

Ideally, the program should be directed by a full ti person, one with vigour, initiative and tact, or if one employee can't be dedicated to the job, a hard

working individual who has energy conservation high on his list of priorities can still accomplish a great deal when given the support of top management. Whomever the person is who is chosen as the co-ordinator, he should have above all enthusiasm, so that others will be caught up in the spirit of saving energy.

Energy conservation can become a grinding and discouraging job, and it takes a very devoted individual to carry it through successfully.

Our organization consists of the co-ordinator, appointed by management, who hopefully will bring knowledge, information, inspiration and motivation to the group, and who has the responsibility to research, develop, co-ordinate and implement the program from the outset and on a continuing basis. The managerial team consists of the managers or senior supervisors of Manufacturing, Manufacturing/Industrial Engineering and Plant Engineering, and on an "as required" basis, Purchasing, Quality Assurance and Design Engineering.

There are a number of benefits to having all departments represented on the committee. Essentially a problem solving and action taking group, the committee is also one of the most effective methods of selling the energy management program.

Our group meets periodically - at least monthly - with the responsibility of establishing long and short term goals and monitoring the results and communicating these objectives and results to management and employees in each part of the company.

The group:
provides the guidelines to formulate and conduct an energy audit
defines the goals attainable
develops ideas on ways to save energy
enlists employee support and participation
disseminates the collected information, and
produces a standard energy accounting system.

The success of any far reaching conservation program, as I stated earlier, is ultimately determined by the amount of involvement of the employees - all of the employees. Let them participate in the energy conservation committee formally or informally. This can be accomplished in many ways:

Through the distribution of literature and the showing of films on conservation.
Through your Suggestion Award Plan.
Through your in-house newspaper or newsletter, or
Through the posting of the goals and accomplishments within their departments and throughout the plants and offices.

The employee should also be involved in the evaluation of the program. They should assist in reviewing the progress of the energy saving, help re-evaluate the original goals, and be involved in revising the program goals as necessary.

PUBLICITY

At our facilities in Canada, our Vice President and General Manager made a pledge in June 1976 to have an active, on-going energy conservation program. From that day we planned to do our share to help our country along the road to energy self reliance by supporting the Federal and Provincial programs. Our target was to reduce, on a voluntary basis energy used in our six Canadian facilities 15 percent per unit of output by the end of 1980, compared to our consumption figures for 1974.

The announcement of our up-coming energy conservation program was made by our chief executive officer. He made clear his commitment by way of the company newspaper, notices on bulletin boards, and letters to the employees. He not only advised them that a program was being started, but also outlined the reason for it, named the committee and the co-ordinator, and outlined the guidelines under which the committee was to operate.

Incidentally, our Vice President and General Manager shows his continuing interest and concern by checking on the progress and accomplishments in the various departments from time to time, offering employees congratulations if results are good, and spurring them on to greater efforts.

We formed an energy conservation task force headed up by our Production and Plant Manager, who incidentally in our organization reports to the chief executive officer. He was given the task of forming an "Energy Management Committee", of outlining the concept and procedures for the overall management program, and representing the company on the 1,100 member companies Transportation Industry Sector (MFG) Energy Conservation Task Force through the Air Industries

Association of Canada.

The task force at Garrett felt that our initial thrust should be through the establishment of employees' awareness programs. We kicked off our program "Hollywood style".

On the day set for inauguration of the program:

We handed out lapel buttons carrying the message "Energy is precious - conserve it!".

We sponsored public interest radio broadcasts on one of our local stations.

We made automobile mileage stickers available.

We handed out reprints of the local newspaper which carried a full page community interest ad aimed at our employees as well as the community at large.

We supplied coasters bearing energy conservation messages for use in our cafeterias.

We posted our fleet of trucks with "Energy is Precious" decals, and 90 kilometers per hour driving stickers.

We draped banners announcing Energy Conservation Week throughout the plants and offices.

We installed signs and stickers over taps and light switches encouraging conservation practices.

We placed "Please Turn Off When Not In Use" stickers on office equipment and shop machines.

We used tent cards on cafeteria tables, on office desks and shop benches, and in our reception areas, carrying energy conservation suggestions.

We equipped our postal machines with overprint stencils aimed at our suppliers and customers to encourage their participation.

We set up special suggestion boxes soliciting energy conservation ideas.

We made energy pamphlets and booklets readily available in our cafeterias and lunch rooms.

We prepared feature energy management news items for our in-plant GML newspaper.

The following pay period we distributed pledge cards with the pay envelopes, asking employees to sign as an indication of their willingness to participate in the overall aims of our energy program. Our respons was 93.5 percent. We followed up each week with energy awareness message cards, while at the same time soliciting ideas to further our in-house program.

Meanwhile, back at the energy management office, we were really working at formal plans for energy conservation, directed by top management. All projects were analyzed, priorities established, and a plan was devised for both the immediate and long range results. Good advertising value, we felt, could be obtained by completing visible projects and showing immediate reductions in energy consumption and the resultant savings. To show the people by eliminating obvious needless waste and indicate to them that we intended to use energy as efficiently as possible, was most important at this early state.

When management is committed to a program, it must constantly check on progress and ask pointed questions when results are not forthcoming. If there is a lack of co-operation between departments, explanations are required. Nothing can be left to drift. When a department is found to be slipping behind and not meeting its goals, management can't wait to see if it will get back on track. The department that finds it has to explain its activity to management on a regular basis soon realizes that a token performance is not acceptable.

The most powerful form of management support is by example.

WE TRIED! THEY BELIEVED! IT WORKED!

In fact, one community newspaper criticized our local Government for its lack of leadership and "business as usual" approach to energy conservation, while commending our company management and our employees and a local community college for the effort we made in responding to the Provincial Government's request for help which had arisen from a fear that the public was "drifting into indifference" concerning the use of energy.

As a result of our management involvement, our people were suitably impressed. We moved to further capitalize on the situation.

We sponsored poster campaigns for the children of our

employees.

We supplied printed material on energy conservation to schools within a fifty mile radius of our plants.

We erected billboards carrying the message "Energy is Precious - Conserve It!" and "We're making progress, but we still have a long way to go!".

We sponsored and attended seminars and hosted energy conservation meetings.

We intensified our employee involvement and worker-management co-operation.

We instituted our Garrett Energy Management (GEM) award program to recognize individuals or identifiable groups of individuals who achieved the most energy conservation saving or suggested improvement during a three month period.

A new participation and partnership in a common goal was born. A new collaboration in problem solving evolved.

The ideas poured in. Our committee had a flood of energy saving ideas to consider and report on. The workers had been given a new role of active participation that could affect the future of their company, and they obviously liked it. They suddenly realized that the continued competitiveness of our organization could depend in part on how effectively we used our energy supplies and how energy cost savings could play a part in future job security.

Since the inauguration of our conservation program in 1976, we have realized energy savings - gas, electricity and water - of approximately $630,000 against a total expenditure of approximately $180,000 over the three and one half year period. We cannot however, accurately assess how far reaching our motivation program has been outside of our plants and offices, as motivating people for energy conservation to the point where it becomes a way of life is difficult.

Until recently, many employees in Canadian companies found it hard to believe there could be an energy crisis. Fuel shortages and the resulting lay-offs due to fuel shortages were things that happened somewhere else - not in Canada. If an employee believes that any efforts to save gasoline, natural gas, electricity are futile, he or she will not be very enthusiastic about the company program. Therefore there is the need to rekindle the individual concern - and this can only be done by making each person aware of ways in which it relates to him.

We feel we have accomplished this. We continually explain that fuel shortages can and will happen in Canada. We show them Government projections indicating an energy shortfall in the mid to late 1980's and we explain to them what the shortage could mean in terms of job security. This may be considered by some as a "negative" motivator, but in the right context it is one of a number of ways to get the message across.

However - don't make the mistake that energy conservation can be introduced, fed to the troops, and then forgotten. Everyone must be motivated initially and their enthusiasm or "fever" maintained throughout the program.

Support from the top is essential.
Building a dynamic team a must.
Initial motivation - most important.
Employee involvement at the outset - critical.
Publicizing energy conservation - logical.
Employee education - most desirable.

But to sustain a program requires constant nourishing to promote any kind of development.
This task is the most difficult!

Good communication is essential. Employees must be reminded by a continuing barrage of highly visible publicity, without of course being overly dramatic, until such time as energy conservation is a way of life.

SUMMARY

In summary then, to maintain an on-going program and continuing enthusiasm in the program, you must:

Hold regular meetings - perhaps monthly.

Involve members of all departments and the union to provide the necessary communications link between the committee and the employee.

Institute and maintain a project and idea list.

Calculate energy use by unit of production. This should be done before the energy program is instituted and monitored while the program is in progress.

Monthly calculation records are recommended.

Attend outside seminars and participate in energy conservation and management seminars inside the company.

Consider outside consultant services in special situations as necessary.

Disseminate posters, booklets, signs, tags, gifts, and other reminders to employees.

Solicit employee participation in ideas either through your already in-place company suggestion plan, or less formally.

Publish energy related information to management and committee members in a monthly report, with progress relative to targets or goals set, and publish energy related information periodically to employees by way of bulletins, magazines or newsletters to inform them of their progress and achievements in reducing energy use.

CONCLUSION

With the costs of all types of energy on an almost straight line increase, conservation is a must. Much of the stress is put on the need for automatic controls, timers and the like. We at Garrett maintain that just as much or more importance should be attached to employee motivation - well motivated employees are, and in our opinion always will be, a very essential ingredient in successful industrial energy conservation programs.

I certainly appreciate the opportunity of being here with you today.

ACKNOWLEDGMENTS

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COMMERCIAL AND INDUSTRIAL ENERGY CONSERVATION PROGRAMS IN ILLINOIS

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ABSTRACT

This paper presents the State of Illinois' evolving role in assisting commercial and industrial firms in identifying and improving inefficiencies in the use of energy.

The energy conservation and development mission of the state and INR for CY 1980 is to:

> "assist Illinois citizens, businesses, and institutions in managing their response to rising energy costs and emerging shortages of petroleum fuels."

Assistance is provided through the dissemination of information about, advice on, and demonstration of conservation practices, fuel switching opportunities and renewable energy sources. Primary attention is given to citizens, businesses and institutions most severely affected by higher energy costs; and to the builders and suppliers of new buildings and equipment.

In 1979, the Energy Engineering Services Section of the Illinois Institute of Natural Resources conducted approximately 50 energy audits and made energy conservation recommendations at commercial and industrial facilities throughout the state. At a later date, Energy Engineering Services personnel reaudited facilities to determine what recommendations were in use and what energy cost savings and consumption reductions had been realized. An analysis of the follow-up data demonstrated that when recommendations (pertaining to operation and maintenance of a facility) were acted upon, energy costs were reduced by 25 to 30%. It was also determined that retrofit modifications could reduce energy costs up to 50%.

The objective of the Commercial and Industrial Energy Conservation Program is to encourage operators of commercial and industrial facilities to take advantage of proven available energy conservation techniques and technologies, insuring more efficient utilization of available energy supplies. During 1979, Illinois' Energy Engineering Services accomplished the following:

1) Forty-one Class A audits were conducted during 1979.
2) INR completed 30 boiler efficiency checks and a boiler efficiency workbook by the end of 1979. INR developed a manual for a waste heat recovery program during 1979.
3) Seven O&M workshops have been conducted throughout Illinois with 475 in attendance.
4) Three hundred seventy-seven organizations have sent 522 individuals to five management-oriented seminars which have been sponsored by INR and four Illinois utilities.
5) INR completed and distributed audit manuals for the following establishments and operations in 1979: restaurants, supermarkets, department stores, industrial buildings, metal fabrication plants, primary metal mills, boiler operations and maintenance, and HVAC operations and maintenance.

INR has audit manuals available for the following: machinery manufacturers, chemical processing industries, food processing plants, and office buildings.

A) Target Audience

The target audience of the Commercial and Industrial Energy Conservation Program is commercial and industrial facility operators and

owners. Any commercial or industrial facility not employing personnel presently trained to conduct energy audits, waste heat audits or boiler efficiency tests will be eligible for assistance.

The target audience was selected for two reasons. Illinois' commercial and industrial sectors are responsible for 32 per cent of the state's total annual energy consumption, making it a target of significant size. Secondly, as illustrated in the introduction, minor operation and maintenance adjustments can result in a substantial reduction of energy costs and consumption.

There are approximately 10,000 commercial and industrial facilities in the state. In 1980, Energy Engineering Services personnel intend to reach operators and owners of 700 commercial and industrial facilities with this program. The number of facility operators and owners to be reached will remain the same for 1981 and 1982.

B) Services

The Energy Engineering Services Section will provide the following specific services to commercial and industrial facility operators and owners:

1) Ten industrial facility waste heat audits will be performed by the professional staff of the section. Each audit will require approximately 15 days time (one day to perform inspection and two weeks to prepare audit report).
2) Four waste heat recovery seminars each lasting eight hours will be conducted for owners, operators and their personnel.
3) One thousand waste heat recovery information manuals will be prepared by section personnel and distributed.
4) Ten energy auditor training workshops, each lasting eight hours, will be conducted for operators, owners and their personnel.
5) One hundred boiler efficiency tests will be performed. Each test will require approximately two hours (one hour to perform test and one hour to prepare recommendations report).
6) One thousand boiler efficiency improvement manuals will be prepared by the section and distributed.

As stated previously, simple-to-perform, inexpensive changes in the operation and maintenance of commercial and industrial facilities can provide substantial energy cost and consumption reductions. The Commercial and Industrial Energy Conservation Program is designed to provide direct technical assistance to operators and owners in the form of audits, education and training in the form of seminars, and information in the form of publications to insure the most efficient energy utilization possible by these two energy consuming sectors. To insure equitable distribution of services, all services will be available on a "first come first served" basis.

C) Program Objectives

In the year ahead, the Energy Engineering Section will:

1) Implement an industrial waste heat recovery audit and education program and prepare a waste heat recovery information manual.
2) Conduct energy conservation workshops.
3) Perform boiler efficiency tests, analyze test results, and prepare and distribute a boiler efficiency improvement manual.
4) Energy Engineering Services will develop a follow-up system to measure energy savings for all program elements. This system will include a coded mailing list, survey cards for seminar participants, and audits.
5) By streamlining audit report write-up and by performing 100 full scale audits, Energy Engineering Services will increase the effectiveness of energy auditing services.
6) Through promotion of Consolidated Building Energy Report System (CBERS) participation workshops for CBERS participants and distribution of energy conservation materia to operators of state buildings, Energy

Engineering Services will increase the number of State buildings using CBERS. They will further strive to reduce the energy consumption of these buildings by 20%.

7) Energy Engineering Services will provide to building managers a set of non-transportation related emergency operating parameters for use in energy shortfalls. Items in the set will include Emergency Building Temperature Restrictions and "Building Management Policy" of the Energy Contingency Council.
8) Energy Engineering Services will co-sponsor, with electric or gas utilities, three energy management seminars targeted to large energy users. Experts will relay information about where energy conservation can be realized, such as HVAC systems, lighting and combustion.
9) Energy Engineering Services will strive to increase the distribution of energy conservation manuals and brochures designed for specific commercial and industrial groups to 2,000 in number.

Illinois Commercial Energy Consumption

During the 1963-77 period, total Illinois commercial energy consumption increased at an annual rate of 3.2%; natural gas consumption increased at 8.8% per year and electricity consumption increased at 5.9% per year.

The commercial consumption of coal decreased at an annual rate of 17.3% from 1963-77 and distillate fuel oil consumption decreased at 0.2% per year during the same period.

In 1977, natural gas constituted 45% of the commercial energy consumed while electricity accounted for 18%.

Illinois Industrial Energy Consumption

During the 1963-77 period, total Illinois industrial energy consumption increased only slightly. Industrial electric energy consumption, however, increased at an annual rate of 5.9% and natural gas consumption increased 2.8% per year during the same period.

The industrial consumption of non-coking coal decreased at an annual rate of 7.3% from 1963-77 and residual fuel consumption decreased 1.6% per year during the same period.

In 1977, natural gas constituted 48% of the industrial energy consumed while electricity accounted for 14%.

Energy Savings for 1980

The total energy savings in the Illinois commercial/industrial sector in 1980 will be 293.72×10^{12} BTU's.

A FIELD-TESTED MODEL OF INDUSTRIAL ENERGY-CONSERVATION ASSISTANCE TO SMALL INDUSTRIES

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ABSTRACT

The University of Tennessee is one of three universities selected by the Industrial Energy Conservation Program of the Department of Energy to develop and demonstrate the concept of an Energy Analysis and Diagnostics Center (EADC). The objective of the EADC program is to develop and demonstrate the methodology through which universities may provide assistance to small manufacturing firms in identifying and analyzing energy conservation opportunities.

The University of Tennessee EADC has completed 52 industrial energy audits of Tennessee manufacturing firms from which over 150 feasible ECO's have been identified and analyzed. The process consists of the following steps: (1) Analyzing energy consumption and costs for a two year period; (2) Conducting a one day on-site energy audit; (3) Analyzing each ECO for potential energy consumption and cost savings; (4) Preparing a technical report to the firm which contains specific recommendations of economically feasible ECO's; (5) Providing the firm with the appropriate financial analysis.

The main emphasis of the process is on quantification of potential energy savings so that the firm has the necessary quantitative data for making a capital investment decision.

The average benefit cost ratio of the EADC program has been calculated to be approximately 8. Reduction in annual energy consumption identified from the ECO's was approximately 13% and reduction in annual energy costs was approximately 10%.

The entire process is described in sufficient detail to permit other universities to follow the field tested methodology and develop their own programs.

INTRODUCTION

The University of Tennessee at Knoxville is one of three universities selected to serve as an Energy Analysis and Diagnostics Center (EADC).

The objective of the program is to provide technical assistance to small manufacturing firms in reducing operating costs by implementing economically feasible energy conservation measures. For the purpose of the EADC program, a small firm is defined as one which does not have the in-house technical resources to conduct an energy audit and do an engineering/economic analysis of potential energy conservation opportunities (ECO's).

The University of Tennessee EADC has completed analyses of 52 industrial energy audits in Tennessee. The present paper describes the operation of the U.T. E.A.D.C. and summarizes the results obtained from the audits completed to date.

CRITERIA FOR SELECTION OF PARTICIPATING INDUSTRIES

Table I[1] shows the rank ordering of the top twenty energy consuming industries in Tennessee based on total consumption of all forms of energy. Table II[2] shows the rank ordering of these same twenty industries by energy intensiveness per employee. These data plus national energy consumption data for the same SIC category were used to establish an energy priority factor for each of the 20 SIC categories. The factors which were considered important for this purpose were:

a) National energy consumption for the SIC category, E_N

[1] Consumption data taken from End Use Energy Consumption Data Base: Series 1 Tables. U.S. D.O.E. Energy Information Administration, DOE/EIA-0014, June 1978.

[2] Employment data taken from Tennessee Directory of Manufacturers, Tennessee Department of Economic and Community Development, 1978.

TABLE I

Rank Order of Tennessee Industries by Energy Intensiveness

Rank	SIC	Industry	Annual Consumption, 10^{12}Btu
1	28	Chemical	182.6
2	33	Primary metal	55.4
3	26	Paper	40.2
4	32	Stone, Clay, Glass, Conc.	34.0
5	20	Food	17.8
6	22	Textiles	9.1
7	30	Rubber	8.5
8	36	Machinery (elect. & electron)	8.5
9	34	Fabric. Metal	7.0
10	29	Petrol. Refining	6.0
11	35	Machinery (non elect.)	4.9
12	25	Furniture	4.8
13	37	Transport. Equip.	3.8
14	23	Apparel	3.0
15	24	Lumber	3.0
16	27	Printing	1.9
17	39	Misc. Manuf.	1.7
18	31	Leather	0.4
19	38	Measuring Equip.	0.4
20	21	Tobacco	0.1

TABLE II

Rank Order of Tennessee Industries by Energy Intensiveness Per Employee

Rank	SIC	Industry	Annual Consumption, 10^{6}Btu/employee
1	29	Petrol. Refining	3,302
2	28	Chemical	2,500
3	26	Paper	2,102
4	33	Primary Metal	1,901
5	32	Stone, Glass, Clay, Conc.	1,616
6	20	Food	379
7	30	Rubber	352
8	22	Textiles	202
9	36	Machinery (elect. & electron.)	169
10	25	Furniture	148
11	24	Lumber	146
12	34	Fabric. Metal	136
13	39	Misc. Manuf.	124
14	37	Transport. Equip.	122
15	35	Machinery (non elect.)	94
16	27	Printing	51
17	38	Measuring Equip.	47
18	21	Tobacco	42
19	23	Apparel	33
20	31	Leather	15

b) Tennessee energy consumption for the SIC category, E_T

c) Tennessee energy consumption per employee for the SIC category, E_E

A weighting factor of 1, 10, 5 was assigned to each of the criteria respectively which resulted in a priority factor, PF, for each SIC category

$$PF = (1)(E_N) + (10)(E_T) + (5)(E_E)$$

The rank order of SIC categories with respect to the PF is shown in Table III. The selection of SIC categories for participation in the pilot program was based on the priority rankings shown in Table III.

PROCEDURE FOR ESTABLISHING INDUSTRIAL CONTACTS

After establishing the priority SIC categories to be served by the pilot program, contacts were made to individual firms using a variety of sources of contacts as follows:

a) Contacts made through the Center for Industrial Services Office of the University of Tennessee Institute for Public Service

b) Contacts made through the Tennessee Manufacturers Association

c) Contacts made through personal knowledge of eligible firms

d) Direct requests for assistance received from firms after the existence of the EADC became known.

THE ENERGY AUDIT PROCESS

The services of the U.T. E.A.D.C. were made available at no direct cost to the participating firms. An indirect cost to the firm involved only the time of designated company personnel to supply information on energy consumption and energy cost for a two year period as well as time spent with the audit team during the on-site visit.

The funding limitations of the pilot program restricted the time spent on-site at the company location to one day. The audit team always involved at least one engineering faculty member and frequently two faculty members plus one or two students, depending on the size of the facility. The audit process involved the following six steps.

1. Prior to the on-site visit, the firm was asked to send to the U.T. E.A.D.C. a copy of all energy bills for the previous two year period.

2. The firm was asked to provide monthly production and gross sales data for the same period so that energy consumption per unit of production and per unit of gross sales could be calculated on a monthly basis. Confidentiality of this data as well as the identity of the firm was assured.

3. A one day site visit was scheduled by the U.T. E.A.D.C. team to conduct an on-site energy aud of the firm and identify potential energy savi which the firm could implement.

4. The energy conservation opportunities identified from the audit were analyzed and a report submitted to the company containing specific recommendations of energy conservation actions for the firm to consider.

5. The analysis of each energy conservation opportunity identified included:

   a) The projected annual energy consumption savings

   b) The projected annual energy cost savings

   c) An economic analysis of the payback period required for the energy cost savings to pay for the cost of implementing the energy conservation opportunities.

6. A follow up contact was made to the firm within 30 to 60 days after receiving the audit report to determine:

   a) Which energy conservation recommendations the firm plans to implement.

   b) Difficulties the firm may have in implementing the recommendations.

   c) Additional information or assistance the firm may need to implement the identified energy conservation opportunities.

THE AUDIT REPORT

The audit report which was submitted to the firm contained the following sections.

Preface

The preface acknowledged the financial support for the program from the Department of Energy, emphasized to the company that the recommendations contained in the report were based on information obtained from a one day visit only, and suggested that the company seek the services of a consulting engineering firm to do necessary detailed engineering design if such in-house capability was not available.

Summary

A one page summary included total energy consumption and cost for the two year period by energy type and a summary of anticipated savings of energy consumption and cost for each recommended ECO contained in the report.

TABLE III

Ranking of SIC Categories Using Weighting Factors

PF = National Consumption x1 + Tennessee Consumption x10 + Tennessee Consumption per Employee x5

Rank	SIC	PF	% of Manufacturing Employment in Tennessee
1	29	17,927	0.3
2	28	17,106	8.8
3	33	12,294	4.0
4	26	12,122	3.4
5	32	9,579	3.5
6	20	2,990	7.3
7	30	2,072	4.4
8	22	1,408	7.1
9	36	1,158	7.3
10	34	1,117	7.6
11	37	996	5.6
12	24	989	3.1
13	35	849	6.5
14	25	834	4.7
15	39	682	2.4
16	27	361	4.8
17	38	309	1.2
18	23	251	14
19	21	230	0.2
20	31	101	3.7

Energy Accounting

Monthly energy consumption and cost for a two year period were presented in bar graph form for each energy type, for total energy, and for energy per unit of production. The bar graphs were generated by a computer graphics terminal using a computer program which was written for this purpose. The company was encouraged to implement this procedure of monthly energy accounting if the procedure was not already being followed.

ECO Analysis

Each identified ECO was described with respect to the specific recommendation to the company for implementation as well as anticipated annual energy consumption and cost savings which would result from implementation of the recommendation. Sufficient calculation detail was included so that the company could do alternative calculations if desired using changed assumptions or conditions from those used in preparing the report. The analysis of each ECO is considered to be the most significant part of the report from the company's viewpoint. A typical ECO analysis is shown on the following page.

Financial Analysis of ECO's

Because of the time limitation of the one day audit, it was generally not possible to give the company an accurate estimate of the cost of implementing the ECO. The company must assume the responsibility of obtaining the cost estimate using resources available within the company or using the services of an engineering consulting firm if necessary. However, the procedure for assessing the financial acceptability of the required capital investment was included in the report. The procedure allows the company to use either the net present value method or the internal rate of return method. The equation used for this purpose is

$$NPV = \frac{SX(1-X^n)}{1-X} - I$$

where n = number of years for evaluating the investment
S = annual energy cost savings resulting from implementation of the recommended ECO based on present energy costs (S would be $10,000 for the example ECO)
I = capital investment required to implement the ECO (to be determined by the company)
$X = \frac{1+e}{1+R}$
e = estimated annual fuel cost escalation (decimal)
R = rate of return on investment (decimal)
NPV = net present value of the investment.

The above equation takes into account the rate of fuel cost escalation.[3]

If the internal rate of return method is used, NPV is set equal to zero and the equation solved by trial and error for X from which R can be calculated from

$$R = \frac{1+e}{X} - 1$$

If the net present value method is used, R is specified which allows a direct calculation of NPV if I is known.

TYPICAL ECO ANALYSIS

Ventilation

Recommended Action - Take measures to prevent loss of building heat through the exhaust systems of the spray booths in the enamel area. This can be done by filtering and returning the exhausted air or by providing local makeup air to reduce the volume of heated air drawn from the rest of the plant. Care should be taken to ensure that summertime ventilation requirements are also met.

Anticipated Savings - It was estimated by plant personnel that approximately 140,000 CFM is being exhausted. It is assumed that this occurs for two shifts per day, five days per week, and that the temperature is 68°F inside and an average of 48°F outside (giving an average temperature differential of 20°F). The heat loss through the spray exhaust is, therefore,

$$1.07 \times 140{,}000 \times 20 = 3 \times 10^6 \text{ Btu/hour}$$

Over the entire heating season this loss amounts to

$$3 \times 10^6 \frac{\text{Btu}}{\text{hr}} \times 16 \frac{\text{hr}}{\text{day}} \times 5 \frac{\text{days}}{\text{week}} \times 22 \frac{\text{weeks}}{\text{season}} =$$

$$5{,}300 \times 10^6 \frac{\text{Btu}}{\text{season}}$$

If it is assumed that 75% of this exhausted energy can be retained through the judicious introduction of makeup air, local to the spray booths, then the savings will amount to $4{,}000 \times 10^6$ Btu/year. The associated cost savings at $2.50 per million Btu for gas will be $10,000/year.

Implementation - To implement this ECO, it will be necessary to install duct work and makeup fans to supply the makeup air at the appropriate locations around the spray booths. Reference should be made to the section of this report dealing with investment analysis to determine the rate of return on the capital investment required to implement this ECO.

SUMMARY OF RECOMMENDED ENERGY SAVINGS

Based on the 52 energy audits completed to date, a total of 157 ECO's were identified, analyzed, and recommended to the firms for implementation. A summary of identified savings by energy type is shown in Table IV.

TABLE IV

Recommended Energy Conservation Savings by Energy Type

Energy Type	No of ECO's	Annual Energy Savings, 10^6 Btu	Annual Cost Savings, Dollars
Gas	86	181,562	$421,840
Electricity	54	26,141	180,077
Fuel oil	29	88,812	237,588
Propane	8	2,224	10,268
TOTALS	177[4]	298,739	$849,773

The ratio of annual dollar value of savings identified to the cost of the program is approximately eight to one. On this basis the program would be considered cost effective.

The implementation rate of recommended ECO's is only about 50 per cent. The barriers to implementation are not fully understood at the present time, and further work is planned to identify and overcome the barriers to implementation of recommended ECO's.

ACKNOWLEDGEMENT

This work was done under subcontract to University City Science Center of Philadelphia, PA.

[3] William T. Snyder and Frederick W. Symonds, "The Influence of Energy Cost Escalation on Payback Analysis of Energy Cost Savings Opportunities" Building Systems Design, Volume 75, No. 6, October/November 1978.

[4] Some ECO's involved energy savings of more than one fuel type.

OKLAHOMA INDUSTRIAL ENERGY MANAGEMENT PROGRAM *

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ABSTRACT

Each and every citizen has been affected by the energy crisis by now. Business and industry have especially been hurt as the rising cost of energy and its dwindling supplies are the twin jaws of a vise rapidly closing in on profits. Much work is being done in large companies; but most small to medium companies have yet to undertake a substantial energy management program. The reasons are many but often they simply do not understand the savings possible or the techniques available.

Recognizing this, the Oklahoma Department of Energy designed a program to acquaint Oklahoma industry with the potential savings available through energy management and some basic techniques. The program is entitled "Oklahoma Industrial Energy Management Program" and is housed at Oklahoma State University. The program is funded by the U. S. Department of Energy through the State Energy Conservation Plan. This paper describes the program offerings, impact to date and plans for the future.

INTRODUCTION

Background - Motivation

The energy crisis is now upon us. Severe winters with subsequent curtailments, plant shut-downs, employee layoffs, etc., coupled with the ever burgeoning cost of energy have made the truth painfully obvious. Easily utilized energy supplies are dwindling, causing the cost of these supplies to escalate rapidly.

To reinforce this, some statistics are presented in the following paragraph (the bibliography contains the necessary references.)

1. Domestic oil production peaked in 1970; domestic gas production peaked in 1974.
2. In 1970, the United States imported 23% of her petroleum needs. In 1975, this figure had increased to 37%. Recently, this figure has been greater than 50% in some months.
3. It took 50 years for U.S. demand to go from four million barrels to sixteen and only 20 years (1950-1970) to go from sixteen to 32. It is expected to double again by 1985.
4. Energy costs are increasing. Some predict continuing increases of 3 to 10% per year plus inflation. To demonstrate the effect of this, Figure 1 is presented.

	1972	1976	1979
Natural Gas	.50	1.60	2.55
Coal-Power Station	.25	.65	1.27
Coal-Other	.40	1.20	---
Nuclear	.23	.24	---
Fuel Oil	.50	2.00	4.10

Figure 1. Cost of Energy Per Million BTU.

Fortunately there are things that can be done to reduce energy consumption and to minimize the impacts of higher costs and curtailments. In commercial buildings, apartment houses, and other large buildings, 30% and sometimes more can usually be obtained (depending upon starting efficiency). In industry, cuts of 30% are also common; in some cases, energy consumption has been reduced by 50%; in at least two cases, reductions have exceeded 60%.

In recognition of these potentials, Congress passed Public Law 94-163, Energy Policy and Conservation Act and Public Law 94-385, Energy Conservation and Production Act providing monies for the development and execution of State Energy Conservation Plans respectively. Without dwelling on the complexities of either, it is sufficient to say that funding for the Oklahoma Industrial Energy Management Program came from the Oklahoma Energy Conservation Plan. The Oklahoma Industrial Energy Management Program is a program authorized by the Governor of Oklahoma, administered through the Oklahoma Department of Energy. Many agencies have provided aid and limited funds. They include, but are not limited to, Small Business Administration, U.S. Department of Energy, and various professional and trade societies. The remainder of this paper describes the Oklahoma Industrial Energy Management Program.

THE PROGRAM

In Oklahoma, industry consumes about 35% of the total energy consumed. This, coupled with 10 to 15% easy savings, 30% eventual savings, and potentials up to 50% savings, means the opportunity is quite large. Industry is profit motivated and quick to respond to

new opportunities. Consequently, as long as energy is fairly priced, industry will respond with future reductions. In fact, industry has shown remarkable progress, substantially reducing consumption while residential usage continues to rise. With this information, Oklahoma embarked upon a program to help industry (particularly small to medium sized ones) meet the challenge.

Program Objectives

The primary objective of the program can be stated simply as:

> "To help Oklahoma industry
> respond to the energy crisis
> in order to improve profits
> and competitive positions."

Notice that this primary objective does not include saving energy, per se. It is therefore necessary that energy management projects be economically justifiable. The program does concentrate on energy problems, so energy saving is a highly desirable by-product.

Sub-objectives of the program include:

1. To save energy.
2. To improve relationships between Oklahoma and her industry.
3. To help Oklahoma assume a leadership role in energy related matters.

The prime mover behind the program is the School of Industrial Engineering and Management at Oklahoma State University (OSU). Consequently, the following sub-objectives also exist:

4. To improve relationships between OSU and state government and between OSU and state industry.
5. To provide opportunities for student training, experience and further exposure through carry-overs into curriculum material.

Philosophy

The philosophy underlying the program is simple. Since energy costs are rising, energy management projects can be very cost effective, thus saving dollars. (Paybacks of substantially less than one year are quite common.) Industry, being profit motivated, will respond to demonstrated opportunities for both profit improvement and improved competitive position. Thus, viable program offerings will be well received. On a national scale, everyone agrees that energy management is good for the country and necessary for her to be competitive in the International marketplace.

PROGRAM DESCRIPTION

The first step was to develop a symbol that would be easily recognizable as representing the Oklahoma Industrial Energy Management Program. The chosen logo is shown in Figure 2.

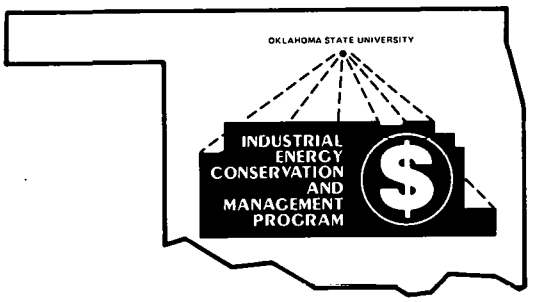


Figure 2. Oklahoma Industrial Energy Management Logo.

Next, it was desirable to provide continuing aid and information, and to open channels of communication among Oklahoma industry. To do these, a newsletter and a system of energy related factsheets were initiated. The newsletters are mailed from Oklahoma State University to all cooperating companies. The fact sheets are developed as required and mailed to participants. A "Do-It-Yourself" energy audit booklet was developed and mailed to state industries. Exhibits and laboratory type experiments have been developed for use in the conferences and in a senior level engineering course in energy management.

Conferences

To make initial contacts with industry, a series of tuition free workshop/conferences were designed for presenting around the state. Twenty to forty conferences were planned over the three and one-half year tenure of the program. The conferences have concentrated on the industrialized areas of Tulsa and Oklahoma City, but they have also been held statewide, including some rural areas. To advertise the conferences, newspaper ads, and radio and television coverage were used. This was backed with a four-page fold-out brochure fully describing the program. A recent copy is reproduced in Figure 3.

As in many projects of this type, actually reaching the intended audience presented a difficult obstacle. Often, a brochure ends up at the wrong desk. To combat this, several mailings are being used. Then, telephone calls are being made to local companies in the area of the specific conference. Finally, professional societies in the state are being notified.

IMPROVING INDUSTRIAL PROFITS THROUGH ENERGY CONSERVATION AND MANAGEMENT

PROGRAM OUTLINE

8:00 REGISTRATION

Introduction, object of conference

How to design, implement and manage an energy conservation-management program including conducting energy audits

9:00 Examples of energy conservation in Oklahoma (Specific suggestions on how to conserve energy citing examples from Oklahoma Industry)

11:45 LUNCH (Dutch Treat)

Local industrial leader(s) in energy conservation presenting their experience including what and what not to try

BREAK

2:45 Round table discussion groups on specific topics (to be chosen). Topics might include Waste Heat Management, Energy Conservation Through Lighting, Boiler Design and Maintenance to Conserve Energy, High Efficiency Electric Motors, etc.

3:30 ADJOURN

WHAT OKLAHOMA INDUSTRIES SAY

"Very useful in introducing energy conservation techniques/ideas to the business and manufacturing community."

"Lots of good information. Starts you thinking on new ideas."

"The conference added many new energy saving ideas to our own collection of thoughts."

"Course was very interesting and helpful."

"Enjoyed it; looking for more of the same."

"Well done. Should help implement new programs."

"Very informative for one day. Found helpful."

"Made use of ideas from last year in our new building and have picked up several new ideas this year."

LOCATIONS

A list of the planned locations for the future conferences are presented below. Each three to four months new locations are added at the rate of one per month. Suggestions for additional locations are welcome as other conferences will be presented over a three-year period.

CITY	DATES	LOCATIONS	HOST
McAlester	October 4, 1979	East Side Wide Acre Room Public Library	McAlester Chamber of Commerce
Idabell	November 15, 1979	Meeting Room Public Service Company	Idabell Chamber of Commerce
Muskogee	February 7, 1980	Room A, Muskogee Civic Center	Muskogee Chamber of Commerce

SPECIAL CONFERENCES

Special conferences for various trade associations, professional groups and local industrial clubs are available. In these cases, the subject matter and discussion groups will be specifically designed (as much as possible) for the industries sponsoring the conferences. Groups or individuals interested in organizing such conferences should contact the program manager; Dr. Wayne C. Turner, School of Industrial Engineering and Management, Oklahoma State University, Stillwater, Oklahoma 74074; (405) 624-6055. Any questions should be directed to him as well as inquiries on locations or special conferences.

REGISTRATION

Pre-registration although not absolutely required enables us to send you a special seminar package of material prior to the conference and to reserve additional handout material for you at the conference. Please return the attached form NOW indicating the location of the seminar you will attend.

Figure 3.

IMPROVING INDUSTRIAL PROFITS THROUGH ENERGY
CONSERVATION AND MANAGEMENT

The ever increasing cost of energy has imposed a severe burden on Oklahoma Industry and is constantly squeezing profits. Participants of this program have reported that implementation of the measures addressed by this series of seminar/workshops has yielded savings of 10-40%. Oklahoma industry is rapidly establishing itself as a leader in this area. This program helps continue and accelerate that response by offering services to the industry of Oklahoma.

First and foremost, a year-long series of carefully prepared seminar/workshops have been offered around the state. These seminar/workshops discuss the purposes and objectives of energy management programs and demonstrate how to design, implement and manage such an effort. They show specific ways to increase profits through energy management and conservation. This year-long series has highlighted and zeroed in on specific Oklahoma experience in energy management. While the seminar/workshops are designed for everyone, special attention is given to medium sized management. An industry leader from your community who has demonstrated leadership in energy management areas will teach a porion of your seminar/workshop. This method ensures that the material presented is pertinent to your needs, timely, and proven cost effective.

Another service for all Oklahomans attending the seminar/workshop is the quarterly energy newsletter, "Enèrgy Channel," reporting the experiences of various Oklahoma industries in energy management. Particular attention will be given to new and improved methods of energy conservation that can be applied in various situations.

WHO SHOULD ATTEND: Anyone who can help control energy consumption should attend the seminar/workshop. Usually, this includes the Plant Engineer, Industrial Engineer, Plant Manager and other managers. There will be substantial discussion time to ensure that every type of industry can profit by attending. Medium sized manufacturing concerns are especially invited.

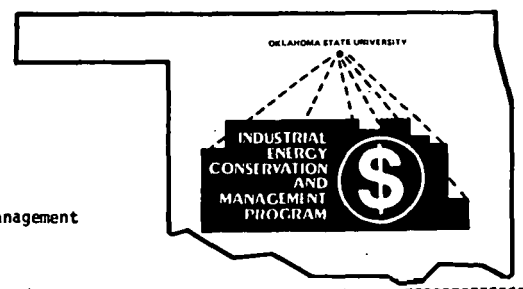
FEE: Because this program is so very important for Oklahoma and the nation, The Oklahoma Department of Energy has made special arrangements to waive the tuition fee for Oklahoma businessmen.

SPECIAL FEATURE: A complete array of special "hands on" working exhibits of energy management tools will be featured. Throughout the seminar/workshop these exhibits will be used to emphasize and demonstrate the principles discussed.

IMPROVING INDUSTRIAL PROFITS THROUGH ENERGY
CONSERVATION AND MANAGEMENT

SPONSORED BY:

Oklahoma Department of Energy,
Small Business Administration,
Department of Energy,
Oklahoma State University
School of Industrial Engineering and Management



PLEASE ROUTE TO PLANT ENGINEERING

NAME_____

COMPANY_____

MAILING ADDRESS_____

CITY_____ STATE_____ ZIP_____

PHONE_____

CITY YOU WILL BE ATTENDING_____

U.S. SMALL BUSINESS ADMINISTRATION
FEDERAL BUILDING-SUITE 670
200 N.W. 5th STREET
OKLAHOMA CITY, OK 73102

POSTAGE AND FEES PAID
U.S. SMALL BUSINESS ADMINISTRATION

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

Figure 3a.

At first, a two-hour optional session on the basics of energy was offered the night before the main conference. In this introductory material, various definitions were given (BTU, Therm, etc.) along with laws of thermodynamics. Then, some conversion figures were given to compare various forms of energy. Finally, a brief discussion on meter reading, demand charge, power factor, and other pertinent material

was presented. The optional session was not popular and was subsequently dropped from further conferences.

Text material is handed out to the participants. Numerous charts, tables, sample letters demonstrating top management commitment, the booklet, Energy Management Guide for Light Industry and Commerce, and a copy of most slides used in the conference are all included in the packet of information.

To date, over 30 conferences have been given, reaching around 485 people from over 330 industries in the state. They are being given at a rate of around one per month.

Newsletter

To maintain momentum and encourage further development, a newsletter has been designed. The purposes are to maintain contacts with participants in the program and to open a statewide communication channel. The newsletter basically:

1. Brings participants up to date on the status of the Oklahoma Industrial Energy Management Program.
2. Continues sharing experiences. Notable successes are shared with suggestions.
3. Suggests new ECO's. As research progresses, new opportunities surface. The best of these will be shared in the newsletter.
4. Provides a forum for the participants to ask questions, offer opinions, or otherwise comment on industrial energy management.
5. Recognizes outstanding activities or contributions by individual companies through articles.
6. Keeps industries informed as to the energy situation and important government activities (such as the National Energy Act.)

Audit Booklet

Even as successful as the conferences have been, not all 3,500 industries in the State of Oklahoma can be reached. In fact, small to medium industries are often too busy on the day of the conference to attend. A way of reaching these was desirable. It was decided to write do-it-yourself energy audit manuals and distribute to state industry free of charge. (Some of this was required by PL 94-385).

A frequency count of Oklahoma industries using the categories of the Standard Industrial Classifications was made. Originally, the intent was to prepare an audit booklet for each classification with a reasonable representation, starting with the most common and then to continue down the list until the number of firms within a classification dwindled.

Booklets for the first three classifications, Printing and Publishing (492 firms), Machinery - except electrical (492 firms) and Fabricated Metal Products (394 firms) were prepared. This experience indicated the basic elements need by each industry not to differ significantly. Therefore, as a matter of economics and efficiency, it was decided to abandon the plan of industry specific materials and instead prepare a generally applicable audit booklet for all industry.

Fact Sheets

Whenever sufficient interest is shown in a subject by cooperating companies, the Oklahoma Industrial Energy Management Program staff prepares a fact sheet and mails it free of charge to all those participating in the program. To date, several fact sheets dealing with such topics as waste heat recovery, the national energy act, consultants in energy areas available to Oklahoma industry, and power factor improvement have been published. To illustrate, the fact sheet on waste heat recovery contained a tutorial on the subject, a survey of applications at both local and national levels, and a listing of major waste heat recovery equipment manufacturers. This fact sheet was very popular and several projects were initiated as a result.

Laboratory Displays and Exhibits

One of the problems encountered is that energy management technology is not very mature (in general). Consequently, the terms technology, and equipment are often new to program participants. To overcome this, exhibits and laboratory type experiments have been and are being designed. These are used in conferences, local talks and papers, and in a senior-level engineering course in energy management being taught at Oklahoma State University. The equipment used or being developed includes:

1. A solar collector connected to a coffee pot to produce hot water for instant coffee.
2. A solar photovoltaic converter used to deliver power to a child's toy.
3. Two power factor experiments designed to show what power factor is and how to correctly design capacitors.
4. A boiler model (fire tube) designed to show stack temperature problems and gas flow interruption possibilities.
5. An energy management environment simulator.
6. A microprocessor programmed to simulate a hypothetical plant's electrical consumption with and without load shedding.
7. Numerous other equipment (combustion monitoring,

air flow indicators, infrared scanners, etc.)

The equipment has proven to be very helpful in explaining energy management.

Class A Energy Auditor Seminar and Certification Program

A series of three day seminars designed primarily for professional consultants and in-house manager-engineers was developed. The program was designed to enable seminar participants to:

1. Discover and evaluate No-Cost and Low-Cost energy saving opportunities.
2. Understand the basic principles of industrial energy utilization.
3. Understand energy use modeling and data collection.
4. Compare project alternatives using sound economic evaluation techniques.
5. Recommend and implement management policies for a long term energy management program.

The program outline is shown in Figure 4.

PROGRAM

I. COURSE OBJECTIVES:

- Audit contacts and references
- Audit classes
- Audit requirements
- Responsibilities of auditor and client
- Cost of audits

II. THE AUDIT:

- Systems approach
- Flow charting
- Procedures
- Desired output
- Audit organization
- Case studies

III. DATA COLLECTION

- Information sources
- Forms
- Equipment inventories
- Interviews
- Instrumentation

IV. ANALYSIS

- Walk thru
- Combustion and heat recovery
- Boiler plants
- Steam distribution
- Electric power
- Waste heat recovery
- Environmental conditioning
- Automatic control equipment
- Evaluation of potential

SPECIAL FEATURE

A special case study of an actual audit will be presented as a workshop "hands-on" learning experience.

Figure 4. Energy Auditor Seminar Program.

Instructions For Energy Auditors, as published by DOE is being utilized as the text for this three-day seminar, but it is heavily supplemented with other material.

The conference has been taught three times to date in Stillwater, Tulsa, and Oklahoma City. At least two more conferences are planned this summer.

Energy Management Modules

As an economical means for transferring energy related knowledge to Oklahoma industry, a series of modules were designed for use with the state's talk-back television networks consisting of close to 50 closed circuit viewing stations. Modules have been (or soon will be completed) for the following subject areas:

1. Waste Heat Recovery
2. Lighting Energy Management
3. Employee Participation
4. National Energy Act
5. Economic Analysis of Energy Proposals
6. Demand Leveling and Power Factor Improvement

These modules provide an indepth coverage of the topic and can range up to three hours in duration. Each program is being taped and is being made available to Oklahoma industry.

Support for this offering came from the Oklahoma State Regents for Higher Education and is part of the efforts of Engineering Extension, Oklahoma State University.

THE FUTURE

The future calls for continuation of all programs as they presently exist and expansion into new areas. For example, the concept of "Energy Fairs" is being explored.

In this, the team would make a trip to various Oklahoma communities and present energy management material to a number of different types of establishments. Numerous concurrent sessions would be employed. For example, Figure 5 might be one possible scenario or outline of the day's activities.

The exact number of concurrent sessions and the subjects to be covered could be varied to fit circumstances. Those in Figure 5 are possibilities. Graduate students especially trained in the specific areas mentioned will be used.

Another possibility is in the area of technical aid. Hopefully, personnel knowledgeable in energy management can be hired to provide aid to Oklahoma

industry on an "as needed basis." These people would not be consultants but would try to answer specific questions. In fact, they could be liaisons for others engaged in energy management consulting. There are no firm plans for starting this service as yet.

In summary, the various offerings of the program have proven quite successful. So long as support continues and a need exists, these activities will continue. However, any program needs review and periodic updating, so future opportunities will always be sought, evaluated and implemented.

Another possible new program is a comprehensive coverage of solar applications in industry. In this multi-day program, the basics of solar technology would be presented followed by an indepth survey of existing and potential applications in industry. The program would be taught via the state's talk back television and would be taped for future reference.

Finally, the Oklahoma Industrial Energy Management Program is trying to become an Energy Audit Diagnostic Center for the region.

SUMMARY

The program offerings basically include:

1. A series of tuition free Industrial Energy Management Conferences (over 50 presented to date involving over 330 Oklahoma industries).
2. Special (in-house) conferences (about 10 to date) for professional groups, government agencies, and industry groups.
3. A free energy newsletter entitled "Energy Channel" mailed to all participating Oklahoma industries.
4. A basic energy Audit booklet including instructions and forms.
5. Technical aid on energy related problems (limited basis).
6. A series of laboratory type experiments involving power factor, solar energy, boiler combustion improvement and other energy related projects.
8. Class A Energy Auditor Seminar and Certification Program (three to date).
9. Energy Management Modules presented via the state's talk back television network. (Four to date).

Plans for the future include expansion of the program to small businesses in general through the Oklahoma Energy Extension Service and more technical aid to participating industries. Also, the module presentations will be expanded and solar utilization in industry will be covered.

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*Reprinted (with permission) from Proceedings State Energy Audit Impact '80, St. Louis, Missouri, April 1, 2, 1980.

ENERGY RESEARCH, DEVELOPMENT, AND DEMONSTRATION

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ABSTRACT

The Energy Analysis and Development Division of the Texas Energy and Natural Resources Advisory Council has the following responsibilities specifically related to RD&D: 1) recommend legislation to the Council to foster the development of increased energy supplies and more efficient energy systems not inconsistent with other laws of the state; 2) administer the Texas Energy Development Fund as directed by the Council; 3) maintain an awareness of all energy-related research of importance to this state in order to promote information exchange and coordination and in order to coordinate and support necessary energy technology research, development, and demonstration; and 4) coordinate and support energy-related technology research, development, and demonstration.

The Technology Development Section carries out these functions by maintaining contact with recognized technical experts; monitoring state, federal, and other energy-related technology development; providing staff support to Council advisory committees; convening technology task forces; coordinating the establishment of Texas energy technology development priorities; soliciting proposals for project funding; providing stimulation, coordination and consultation with regard to development of energy projects and submission of energy-related proposals to federal agencies. The section is staffed by a manager, three engineers, and secretarial personnel.

The rules adopted by TENRAC for administering development grants establish the following funding criteria for project selection: 1) specific to Texas, 2) near term significance, 3) supported by matching funds, 4) not redundant, and 5) related to energy supply and conservation technology RD&D.

Proposals are solicited by issuance of statements of program intent (SPI). Each proposal is evaluated by at least four technical experts outside the staff including, to the extent possible, representatives of the academic community, private industry, federal government and state government. TENRAC authorizes contract negotiations pursuant to staff recommendations based on the established evaluation process.

Presentation includes up to date description of results of the solicitations, evaluations, recommendations, and contract awards.

Even prior to the Arab Oil Embargo of 1973 it was recognized in Texas that domestic petroleum and natural gas reserves and production were declining and that the state must respond aggressively to the need for a major energy transition. On the basis of this, the Governor's Energy Advisory Council was created by executive order by the Governor to recommend an effective response.

The studies conducted by this group led to significant legislative action in 1975 including the legislative creation of the Governor's Energy Advisory Council chaired by the Governor and including a number of the leading elected officials of the state and heads of major agencies with responsibilities directly related to energy production, utilization, and regulation. The observed need for state energy development activities resulted in the introduction of legislation for the creation of an energy development fund which did not make it through the legislative process.

In 1977 the legislature created the Texas Energy Advisory Council composed of the same basic constituency but chaired by the Lieutenant Governor and focused in its efforts on policy and technology analysis and development. $1,500,000 was appropriated to an energy development fund potentially as large as $5,000,000 to be administered by the Council and to strengthen its technology development function. Previous Council functions related to information dissemination and administration of federal programs

such as the state energy conservation plan and the energy extension service were moved into the Governor's Office of Energy Resources.

The analysis of 1978-79 EDF funding appearing below indicates the distribution of funds and the level of matching funds and some of the other technology projects which grew out of the Council's initial efforts energy technology development. A number of the projects have been completed and the resulting reports are now available as indicated in the publication list appended to this paper.

ANALYSIS OF 1978-79 EDF FUNDING

AREA	NO. OF PROJECTS	EDF FUNDS	GENERATED MATCHING FUNDS	TOTAL RD&D INVESTMENT
Basic EDF Projects:				
Lignite	6	$224,209	$378,424	$602,633
Geothermal	3	203,303	781,238	984,541
Conservation	8	137,291	416,360	553,651
Special Projects	5	106,870	51,985	158,855
Solar	9	215,108	273,509	488,617
Wind	3	74,356	55,225	129,581
Biomass	3	127,177	281,008	408,185
Monitoring & Reporting		59,979	19,223	79,202
Administrative Expense	—	150,000		150,000
EDF SPECIFIC TOTALS	37	$1,298,293	$2,256,972	$3,526,042
Additional Projects Generated:				
Border Solar Demo	1			$282,000
Other Projects	5			1,089,000
TOTALS	6			$1,371,000

In 1979 in a move to expand the scope of the Council and to improve the coordination between state activities related to both energy and natural resources the legislature created the Texas Energy and Natural Resources Advisory Council (TENRAC) initially composed of those listed in the following table with Mr Ed Vetter functioning as both a citizen member of the Council and the executive director.

TEXAS ENERGY & NATURAL RESOURCES ADVISORY COUNCIL

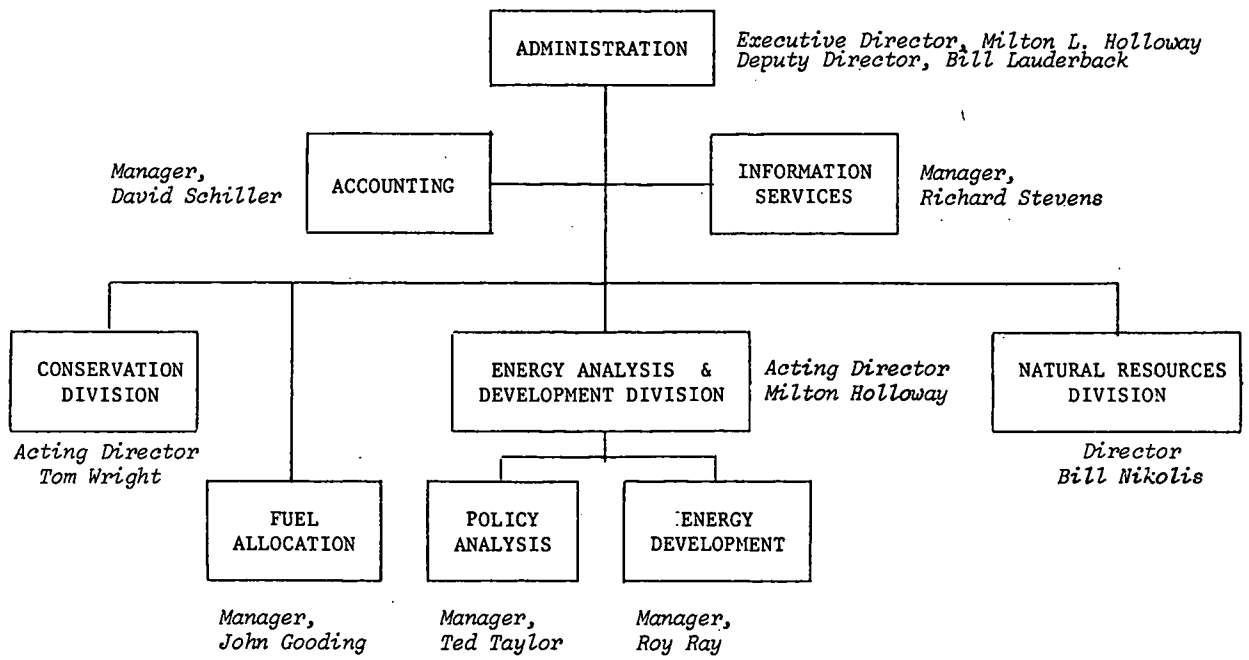
Gov. William Clements, Jr., Co-Chairman
Lt. Gov. William P. Hobby, Co-Chairman
House Speaker Bill Clayton, Vice-Chairman
Attorney General Mark White
Railroad Commissioner Mack Wallace
Agriculture Commissioner Reagan Brown
Public Utility Commissioner Garrett Morris
General Land Office Commissioner Bob Armstrong
Comptroller of Public Accounts Bob Bullock
Bureau of Economic Geology Director Bill Fisher
Air Control Board Chairman John Blair
Texas Water Development Board Chairman A. L. Black
Texas Parks & Wildlife Chairman Perry R. Bass
Senator Peyton McKnight
Senator Bill Meier
Representative Joe C. Hanna
Representative Tom Craddick
Citizen Edwin Lockridge Cox
Citizen Michael T. Halbouty
Citizen Henry B. Harkins

Citizen Ed Vetter, Executive Director

The appropriation for energy development grants was expanded to $3,750,000 and the wording describing the range of applications was broadened to include "research, development, and demonstration of alternate energy supplies and energy conservation technologies of particular importance to Texas."

The staff organization chart which follows reflects recent changes in the staff structure resulting from the elevation of Dr. Milton Holloway to the position of executive director. Mr. Ed Vetter continues to function as energy advisor to the governor and as a citizen member of the council.

TEXAS ENERGY AND NATURAL RESOURCES ADVISORY COUNCIL
Staff Organization



The Energy Analysis and Development Division of TENRAC has the following responsibilities specifically related to RD&D: (1) recommend legislation to the council to foster the development of increased energy supplies and more efficient energy systems not inconsistent with other laws of the state; (2) administer the Texas Energy Development Fund as directed by the council; (3) maintain an awareness of all energy-related research of importance to this state in order to promote information exchange and coordination and in order to coordinate and support necessary energy technology research, development, and demonstration; and (4) coordinate and support energy-related research, development, and demonstration.

The energy development section carries out these functions by maintaining contact with recognized technical experts; monitoring state, federal, and other energy related RD&D; providing staff support to council advisory committees; convening technology task forces; coordinating the establishment of Texas energy technology development priorities; soliciting proposals for project funding; providing stimulation, coordination and consultation with regard to development of energy projects and submission of energy-related proposals to federal agencies.

Previous staff efforts, conclusions from completed and ongoing RD&D projects, input from task forces in the various energy resource areas, and interaction with technical experts have resulted in initial potentially changeable estimates of energy development funding for the current biennium indicated in the following table.

POTENTIAL TECHNOLOGY DEVELOPMENT FUNDING ESTIMATES

PROJECT AREA	80-81 FUNDING LEVEL $K	%
LIGNITE	800	21.3
GEOTHERMAL	200	5.3
WIND	200	5.3
BIOMASS	600	16.0
SOLAR	410	11.0
CONSERVATION	675	18.0
OIL AND GAS	70	1.9
NUCLEAR	15	0.4
TEPP	500	13.3
INNOVATIVE	130	3.5
OTHER (REPORTS, MONITORS, RD&D PRIORITIZATION)	150	4.0
	$3750K	100.0%

Up to March 15, 1980, statements of program intent (SPI's) have been issued for solar, wind, biomass, conservation and lignite proposals as described in the following list:

SPI NUMBER 80-S-1

Solar powered residential comfort conditioning in a medium to high humidity environment.

SPI NUMBER 80-S-2

Thermal storage of solar energy.

SPI NUMBER 80-S-3

Industrial solar applications.

SPI NUMBER 80-S-4

Agricultural solar applications.

SPI NUMBER 80-S-5

Solar lighting for commercial buildings.

SPI NUMBER 80-S-6

Establishment and Operation of the Southwest Residential (Photovoltaic) Experiment Station.

SPI NUMBER 80-S-7

Documentation of the extent of solar energy commercialization in Texas.

SPI NUMBER 80-W-1

Collect, analyze and prepare wind velocity data for use in establishing statewide data on a regional basis for wind energy utilization.

SPI NUMBER 80-B-1

Construct and demonstrate a small-scale (1000 gallons per day or less) commercial alcohol distillery to provide functional information for use by the general public.

SPI NUMBER 80-B-2

Survey practical sources of biomass to determine availability and geographic distribution for cellulose conversion into alcohol.

SPI NUMBER 80-C-1

Improved efficiency in commercial and residential HVAC systems.

SPI NUMBER 80-C-2

Industrial heat pump for building and water heating.

SPI NUMBER 80-C-3

Non-residential groundwater heat pump retrofit demonstration.

SPI NUMBER 80-C-4

Demonstration of energy conservation through improved control, by retrofit of commercially available microprocessors and software to existing energy systems.

SPI NUMBER 80-C-5

Thermal storage for HVAC systems of 25 tons cooling capacity or greater.

SPI NUMBER 80-C-6

Energy conservation in agricultural operations by development of improved, energy efficient irrigation systems.

SPI NUMBER 80-L-1

Study of low Btu fixed-bed gasification of lignite pellets.

SPI NUMBER 80-L-2

Research and/or development of advanced technologies for the use of lignite as an industrial fuel.

SPI NUMBER 80-L-3

Demonstration of advanced technologies for the use lignite as an industrial fuel.

SPI NUMBER 80-L-4

Research, and/or development related to particular control systems.

SPI NUMBER 80-L-5

Research, development, and/or demonstration related to the disposal or use of solid wastes from existing or advanced (e.g., atmospheric fluidized bed combustion) technologies for lignite combustion.

SPI NUMBER 80-L-6

Research, development, and/or demonstration related to environmental issues not included in SPI 80-L-4 or 80-L-5.

In the initial round of solicitations for which proposals were submitted by March 3, 1980, there were 6 biomass proposals requesting $901,718; 4 wind proposals requesting $280,641; and 16 conservation proposals requesting $739,476. Total requests in this group amount to $2,740,578.

The rules adopted by TENRAC for administering development grants establish the following funding criteria for project selection: (1) specific to Texas, (2) near term significance, (3) supported by matching funds, (4) not redundant, and (5) related to alternate energy supply and conservation technologies RD&D Each proposal is evaluated by at least four technical experts including to the extent possible representatives of the academic community, private industry, federal government and state government.

The proposals received to date are in the evaluation process at the time of this publication. Additional information available at the time will be included in the presentation to the conference.

TEXAS ENERGY DEVELOPMENT PUBLICATIONS

EDF-004 Project Status Reports (January, 1979)

EDF-005 Input-Output and Risk Analysis for a Regional Energy Development Bank - Weatherby, Jr., Kieschnick, Jr., Peach and Wieferman (September, 1978, Project #SP-1-2)

EDF-006 Solar Energy: An Economic Analysis, Parts I & II - Hill, Jonish and Teske (December, 1978, Project #SP-2-6)

EDF-008 Solid Fuels Conversion Costs for Texas - Coal and Lignite Utilization in Electric Power Generation and Other Industries - Singleton, Jr., Muthukrishnan, Taylor III, and Thompson (January, 1979, Project #SP-2-10)

EDF-009 Community-Level Impacts Projection System (Clips) - Monts and Bareiss (February, 1979, Project #SP-3-6)

EDF-011 Integrated Assessment of Texas Lignite Development, Volume I Technical Analysis (April, 1979, Project #L-4-7)

EDF-011 Integrated Assessment of Texas Lignite Development, Volume II Policy Analysis (April, 1979, Project #L-4-7)

EDF-013 Investigation of the Conservation Potential of Residential Heat Pumps with Thermal Energy Storage - (May, 1979, Project #C-4-2)

EDF-014 Groundwater Heat Pump HVAC Demonstration Project, Phase I -Design Development (June, 1979, Project #C-6-1)

EDF-015 Development and Demonstration of Low Cost Heliostats, Northrup, Inc., (July, 1979, Project #S-5-5)

EDF-016 A Consumer's Guide for Wind Energy in Texas, Vaughn Nelson, (July, 1979, Project #W-1-5)

EDF-017 Demonstration of Solar Energy Conversion of Agricultural or Industrial Wastes of Fuels, Dow Chemical Co., (May, 1979, Project #B-0-2)

EDF-018 Alternative Energy Sources for Agricultural Applications Including Gasification of Fibrous Residues, Parker, (August, 1979, Project #B-1-1)

EDF-019 Economic Feasibility for the Conversion of Texas Lignite to Petrochemical Feedstocks, Richardson, (August, 1979, Project #L-3-1)

EDF-020 Systems Analysis of the Texas Gulf Coast Geopressured Resources, C. Dale Zinn, (July, 1979, Project #G-1-2)

EDF-021 Feasibility Analysis of a Regional Energy Development Bank, Jared E. Hazleton, (August, 1979, Project #SP-1-3)

EDF-022 Wind Assist Irrigation and Off-Season Power Generation, Earl Gilmore, Vaughn Nelson, Kenneth Starcher, Robert E. Barieau, (Project #W-4-1)

EDF-023 Geothermal Exploration in Trans-Pecos, Texas, Robert F. Roy and Bruce Taylor, (Project #G-2-3)

EDF-024 Investigation of a Passive Wall and a Movable Roof of a Test Building, Harry T. Mei, (Project #S-1-1)

EDF-025 Energy Conservation Through Improved Irrigation System Design and Methods, William M. Lyle, (Project #C-5-2, November 30, 1979)

EDF-026 Low-Cost Solar Heating and Cooling Retrofit Demonstration, Gary Beyer, (Project #S-1-9)

EDF-027 Demonstration of a Low-Cost, Indirect Evaporative Cooling System, Dr. Jerry R. Dunn, (Project #C-2-4)

EDF-028 Supersorbent Polymers for Dehumidification, Richard William Tock, (Project #C-1-3)

ENERGY TECHNICAL ASSISTANCE: INDUSTRIAL PROCESSES PROGRAM

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ABSTRACT

The Energy Technical Assistance Division of Texas Engineering Extension Service (TEEX) has implemented an energy conservation program to assist small industry in using energy more efficiently. This full time service, an outgrowth of the Texas A&M University College of Engineering activities, is available through support of Texas Energy and Natural Resources Advisory Council. Engineers with industry and consulting experience are located in Arlington and Houston TEEX offices.

The Energy Technical Assistance Division of Texas Engineering Extension Service has implemented an energy conservation service, the Industrial Processes Program, to assist small industry in using energy efficiently. The State of Texas Energy Conservation Plan (1) developed by the Texas Energy and Natural Resources Advisory Council (TENRAC) in 1977 recognized the need of "selling" the wisdom of energy conservation investments to industry having little or no in-house technical expertise in energy related activities. The nature of our energy problem is such that efficient utilization of energy and individualized planning are necessary parts of the solution. These activities can also be a significant influence in making Texas industry more productive and competitive in the marketplace.

Energy technical assistance was initiated in February 1979 when the first engineering energy specialist was placed in Arlington, Texas. Before the end of the first quarter of 1979, two engineers were working in Arlington and two in Houston. At first the Arlington office called on small industry to make them aware of the new service. Soon word began to spread and by the end of the second quarter of 1979, the majority of small manufacturers served were by referral. Occasionally the engineers have accepted invitations to discuss the Industrial Processes Program, energy conservation, and energy management with technical and industrial organizations. These discussions have resulted in requests for assistance. Other organizations such as the Dallas Minority Business Association have recommended our services to the small manufacturers they serve. The Houston office found calling on the chief operating officers of small manufacturing companies a convenient and effective method of making manufacturers aware of the service. TENRAC and the Department of Energy (D.O.E.) Conservation Group located in Dallas have provided referrals from inquiries they have received. No attempt has been made to obtain mass media advertisement because of the desire to maintain the capability to respond to requests for technical assistance within a few days or weeks after an inquiry is received.

During the first twelve months of operation, the following major milestones were accomplished:

- Conducted more than 182 energy survey projects in 33 different cities.
- Provided recommendations for specific energy conservation measures to save more than 23,642,102 KW-HRS, 392,560 MCF (natural gas) or 678,584 million BTUs per year.
- Distributed new technology information to industry (e.g. D.O.E. technology transfer documents).
- Presented 4 technical programs to more than 107 industry representatives.
- Prepared and presented a two credit-hour graduate course on energy management to 18 personnel.
- Presented three 2-day seminars to certify energy auditors for TENRAC's grant program for schools, hospitals, local governments and health care institutions.

Based on average energy costs, these potential annual energy savings represent a current annual cost savings of $1,887,828. Furthermore, energy conservation measures implemented will accumulate savings ye after year. For example, the above potential annual savings during a 10 year period with a 10% per year

energy price increase represents $30,087,166 in potential savings. These potential savings projections are based on methods of using energy more efficiently without reducing production, services, quality or quantity of goods, or personnel comfort.

Industry is Texas' largest consumer of energy, as shown in Table 1.

TABLE 1: TEXAS ENERGY CONSUMPTION (1975)

CONSUMER	% OF TOTAL
Industry	46.0
Agriculture	2.3
Transportation	26.3
Residential	16.9
Commercial	8.5

Therefore it is logical to concentrate on industry for any plan to significantly improve the overall efficiency of energy use in Texas. Even small manufacturers, those without in-house energy information or technical expertise, consume a significant amount of energy and are worthy of conservation efforts as denoted in the State of Texas Energy Conservation Plan. This fact is illustrated by observations from energy technical assistance activities in Houston. Average electrical energy consumption in 1979 for Houston residences was 13,500 KW-HRS. The small manufacturers served by the Houston office averaged 734,400 KW-HRS. This ratio of small manufacturers to residences is 55 to 1.

Our basic approach is to assist industry in using energy efficiently. Energy conservation should be a tool for increasing industry effectiveness or productivity. Therefore when we communicate to industry the importance of energy conservation, we speak in terms of increasing the productive output per unit of energy consumed, or simply an increase in the efficiency of energy use. This basic concept appears to be readily accepted by industry as opposed to energy conservation by reducing production or promoting a no-growth policy. In fact, we have provided energy technical assistance for energy usage in several expansion projects where additional production is planned.

The efficient utilization of energy is smart business, saves money, requires technical and management skills, and requires careful planning. Many small to medium sized manufacturers do not have the information or specialized skills to identify energy conservation opportunities beyond the simple obvious techniques such as turning off lights. It is essential that industry plan their energy use just as they do any other resource (e.g. cash flow, raw materials, etc.). To accomplish successful energy management on a continuing basis, the small manufacturer must have an organized plan. The steps shown in Figure 1 are a logical flow of work to accomplish the efficient utilization of energy. This diagram is frequently used in discussing energy management with small manufacturers. Figure 2 illustrates an alternate management plan that is used in discussion depending on the company and individuals involved. Each block of these energy management plans is a suitable subject for a separate paper and discussion, and time does not permit detailed discussion of these elements for this session.

There are no short-cut gadget methods of accomplishing successful energy management or identifying energy conservation measures. These tasks are successfully accomplished by detailed work. The identification and detail of energy conservation measures most often is a direct function of the practical experience of the engineer involved.

In general, the following are accomplished for each client served:

- Conduct walk-through energy survey.
- Determine energy situation (e.g. analyze utility bills, identify major energy usage).
- Identify practical energy conservation measures and their potential benefits.
- Make follow-up visit to report results of survey and analyses.
- Discuss sustaining energy management program.
- Make sure client knows we are available for future energy related activities.
- Distribute new technology and additional applicable information to the client as the data becomes available.

Typical examples of specific energy conservation measures recommended are shown in Table 2.

The success of a technical assistance program such as the Industrial Processes Program depends on many factors other than basic skills in engineering

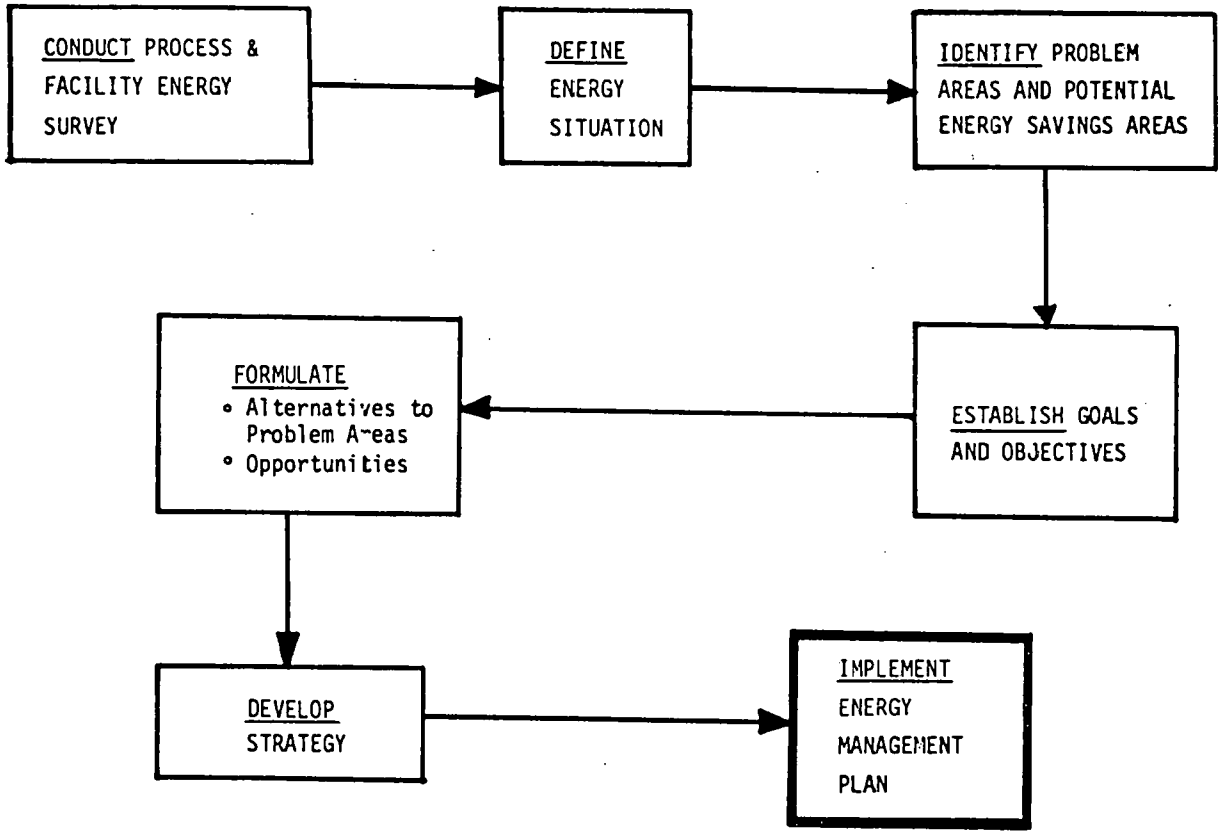
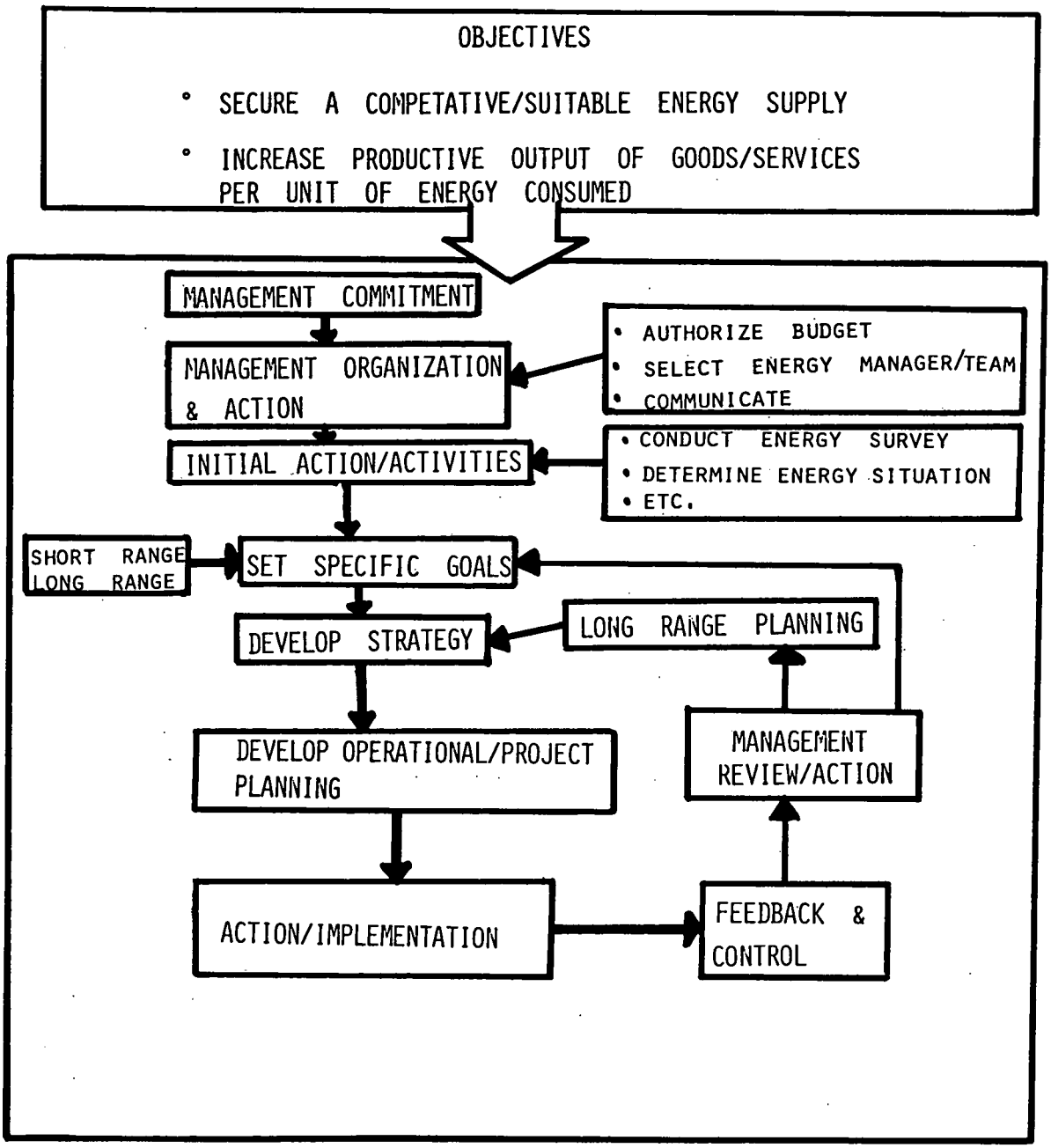


FIGURE 1 - ENERGY MANAGEMENT PLAN

FIGURE 2

MANAGEMENT ACTION PLAN



analyses. Several significant observations include the following:

° The attitude of the engineer toward the small manufacturer should be of a customer or client type relationship. Winning the confidence and cooperation of the client is very important in effecting the assistance. The client is showing his consideration by permitting the service, and the engineer should look upon this as a favor to him. Professional engineers with industry and consulting experience obtain the confidence of plant personnel readily and should be capable of communicating with the different levels of personnel. Engineers in the Industrial Processes Program exercise judgement in working with each individual client. Flexibility is required in the format and type of information provided to each client. The technical and management abilities of personnel in small industry vary considerably. It is very easy for the technical professional to intimidate the non-technical plant manager or decision-maker with engineering formulas and mathematical details of engineering and economic analyses, or inundate them with complex materials which may not be applicable to their situations. The key is to communicate energy conservation measures and benefits in a manner or format that the individual can understand and is willing to consider. Information provided should be adequate for basing decisions or initiating actions. Only measures which are ultimately incorporated save energy; thus, conveying their importance is vital to the client's efficient energy utilization.

° The term "energy audit" is very commonly used. It is suggested that when working with industry, the term "energy survey" be substituted. "Audit" seems to draw a negative reaction or feeling such as one might have for an outside inspector.

° Full time professional personnel available and readily accessible make it convenient for the small manufacturers to utilize and benefit from the service.

This program is sponsored by the Texas Energy and Natural Resources Advisory Council (TENRAC) located in Austin, Texas. TENRAC's project manager is Mr. Pete Baldwin. The Texas Engineering Extension Service appreciates the opportunity to serve the citizens of Texas by conducting the Industrial Processes technical assistance program. The continuing cooperation and support of TENRAC and D.O.E. Conservation Group in Dallas has contributed to the program's success and rapid achievement of energy savings.

REFERENCES

(1) State of Texas Energy Conservation Plan, June 1977, Volume II - Plan Report.

TYPICAL ENERGY CONSERVATION MEASURES: TABLE 2

- Adjust fuel/air ratio of boiler.
- Insulate hat presses.
- Insulate vacuum mold machine.
- Repair compressed air leaks.
- Reduce pressure setting of air compressor.
- Install insulation over office ceiling.
- Insulate chill water tank.
- Test alternate hat coating that cures at room temperature.
- Install capacitors to improve power factor.
- Implement schedule provided to minimize operation and reduce demand of shop air-conditioning units.
- Repair seals on plastics pre-heat oven.
- Repair seals on heat treat furnace.
- Incorporate positive seal design for heat treat furnace.
- Increase chill water temperature.
- Recover waste heat from boiler to pre-heat feedwater.
- Evaluate replacing inefficient furnace with slot forge furnace.
- Duct hot condenser air discharges from refrigeration cases directly outdoors.
- Use solar energy to provide 140 F water.
- Specify energy efficient motors.
- Efficient & fluorescent lighting recommendations.
- Evaluate recovering waste heat from ladel heaters to pre-heat material and combustion air.
- Use storage to reduce peak operating loads.
- Incorporate load shedding.
- Incorporate alternate epoxy heating & curing methods for specific operation.
- Incorporate box recycling.
- Recover waste heat from curing ovens and testing units for use in epoxy pre-curing.
- Recover waste heat from swaging furnace to pre-heat stock material.
- Install flow reducers on hot water outlets.
- Insulate diode presses.
- Implement electrical load management by scheduling notching machine.

EDUCATION AND TRAINING PROMOTE ENERGY CONSERVATION

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ABSTRACT

Significant progress has been made in reducing energy consumption via housekeeping, maintenance, procedural changes and implementation of several hundred capital-related energy conservation projects. Better understanding of utility operations by operators was gained through a formal training program. A comprehensive Distillation Training Program (DTP), consisting of videotapes and texts, was produced for training plant operators and supervisors. Justification for the DTP program was the total annual energy cost for distillation operations.

Hercules Incorporated is one of the ten major chemical companies in the United States with its headquarters located in Wilmington, Delaware. Net sales in 1979 were $2.4 billion. Hercules markets worldwide over 1000 industrial chemicals produced at 87 major plants. About 50 of these plants are located in the United States. The balance are situated in 29 overseas locations.

In our 67 years of operation, we have developed processes that take low-value or waste materials such as tree stumps, cotton linters, citrus peels and oil refinery gases, and make them into high value products used by most of the world's major industries as raw materials in manufacturing their products.

The theme of this conference is energy conservation - a subject that has gained significant recognition by the industrial, commercial, and private sectors since energy prices began their exponential price increases. The total industrial sector has reduced its energy consumption by about 14% when measured against the base year of 1972. The chemical industry has demonstrated an aggregate Btu per unit of output reduction of greater than 20%. Hercules is proud that it has been a major contributor to the chemical industry's efficiency improvement. For the 12-month period ending in December 1979, Hercules' domestic plants had reduced the amount of energy to produce a pound of product by 31% compared to the 1972 base year. Savings of this magnitude can be better appreciated when discussed in terms of actual Btu savings. This level of effort represents 23 trillion Btu or 3.9 million barrels of fuel oil equivalent not consumed during 1979. In a different perspective, it represents 90, 5000-gallon truckloads of oil per day.

Hercules' management chartered its Energy Conservation Group in 1972 - a year

before the Arab Oil Embargo. In fact, our interest and concern for efficient utilization of energy predates the 1972 charter. A corporate report, describing an energy survey conducted at a west coast plant, covers terms and phrases that the average man on the street is now familiar with such as steam balances, turbines, insulation, motor efficiency, load shedding, and boiler efficiencies. The interesting thing about this report is that it is dated 1921 - 52 years before the embargo.

We approached the subject of reducing energy consumption in about the same manner as any other industrial concern. The first order of business was to develop a method and procedure for measuring progress. The performance measuring system that we developed, plus potential opportunities for saving energy, were reviewed with plant personnel. Initially, emphasis was placed on "quick-fix" housekeeping items such as lighting, steam leaks, insulation, faulty steam traps, turning off of idle equipment and improving boiler efficiencies. Following a period of planning, capital-intensive projects that related to energy conservation started to unfold. Over the past several years, Hercules has funded and implemented hundreds of energy conservation projects ranging from individual funding levels of several thousand to millions of dollars. Examples of some of our energy conservation projects are: utilization of waste by-products as fuel, recovery of process waste heat, installation of waste heat boilers, boiler blowdown heat recovery, modified distillation columns, low excess air fuel burners, application of computers for efficient use of energy, low level heat recovery, process procedural changes, equipment modifications and cogeneration - both electrical and mechanical. I would like to note that Hercules' domestic plants cogenerate about 16% of their total electrical requirements and an additional 14% electrical needs in the form of mechanical shaft horsepower. We are also investigating additional use of coal and have a pilot program underway for harvesting and burning non-commercial timber.

Capital expenditures for energy conservation projects vary from year to year; however, approximately $15 million that Hercules spent on energy conservation during 1979 is typical of our level of spending for this activity. All capital expenditures must meet internal rate-of-return criteria. Money spent for some energy conservation actions such as operating procedure changes, yield improvements, maintenance and increased efficiency built into new plant designs are in excess of the above figure.

Our conservation program has been very successful as the result of individual plant activities and the close association of corporate energy conservation and plant personnel. The single most important ingredient was a one-on-one personal contact with plant management and supervision. This was supplemented with a newsletter system that provided information on world and

national energy matters, an exchange of plant energy conservation activities, and updates of corporate energy conservation performance and energy price forecasts. Periodic seminars were held to provide an opportunity for exchange of information among all levels of management and supervision from plants and corporate headquarters.

The extensive network of data reporting, project submissions, plant activities, newsletters, personal contacts and seminars left one basic ingredient out of the recipe: the plant operator. For a totally effective program, we decided that a corporate approach was required to get operators and first line supervision actively involved in the energy conservation program. It is our belief that these types of individuals possess a wealth of knowledge and ideas that have not been tapped. More effective implementation of completed energy conservation projects and procedural changes, as well as developing an understanding and appreciation of energy problems, will result from effective education and training programs.

The first area that we considered for operator-supervisor training was the powerhouse and utilities. For years, powerhouse operations were looked upon as necessary evils that supplied steam to processes but did not contribute to profits and earnings. This attitude was a carryover from the days when fuel oil cost about five cents per gallon with resulting steam valued at fifty cents per thousand pounds in contrast to today's typical steam value of $6 to $7 per thousand pounds. In fact, we have plants with steam boilers that at one time operated exclusively on spent wood chips and process equipment was installed for the sole purpose of consuming excess steam. This, of course, is no longer the case since operations have expanded at these plants and it has become necessary to supplement by-product fuels with purchased fuel oil and natural gas.

When energy was cheap, the general plant attitude was that the primary purpose of boiler operators was to produce steam. Efficiency of operations was secondary. The primary objective of the plant was to produce salable products. Consequently, boiler operators felt like outsiders and not members of the overall plant team. This attitude started to change several years ago when projects were initiated to improve efficiencies of steam boilers and other utilities on a company-wide basis. Today, practically all of our boilers and organic fluid heaters are equipped with blowdown heat exchangers, air preheaters, economizers, state-of-the-art fuel burners, flue gas monitoring - control systems and/or advanced instrumentation.

To supplement the physical changes, we purchased a complete videotape-textbook training program from Learning Unlimited, Incorporated. This program consists of videotapes on combustion principles, boiler operation, turbines and generators. One individual with an extensive back-

ground in utilities operations and supervision was assigned the task of instructing personnel at specific plant sites. To date, approximately 200 people - operators and supervisors - at seven Hercules plants have completed the program and been awarded certificates of completion. This training program has given everyone the opportunity to understand the importance of his job, select the proper method of operating equipment, spot trouble and solve problems, determine what constitutes waste and savings, and appreciate the magnitude of dollar savings that can result from the correct way of doing his job. In all cases, we have seen a significant increase in job satisfaction, enthusiasm to promote energy conservation, development of the individual thinking process and communication. It is difficult to measure the tangible benefits of this program; however, testing of individuals one year after completion of training showed an 80% retention of course material. Perhaps the program can be summed up best by the question asked by several trainees: "Where was this program 5, 10, or 15 years ago?"

The success of the boiler operator training program prompted us to look at developing similar programs for the production areas of the plants. It was decided that a training program should be directed at a specific unit of operation rather than operations in general. Furthermore, the selected operation must be one that is both energy and operator sensitive.

A cursory review of unit operations indicated that distillation and evaporation fit our criteria. We then conducted a survey of distillation operations for Hercules' domestic plants. Estimates showed that first-cost investments exceeded $75 million for distillation equipment. Analysis of 1978 operating costs indicated that energy consumption exceeded $25 million per year or about 25% of the total value of energy consumed. This confirmed that liquid-liquid separation was our most energy intensive operation and that plant operating personnel would benefit from a professionally developed training program.

Plant operators are trained to work from standard operating procedures but are seldom taught a basic understanding of internal operation of expensive and complicated equipment. Often times, operating techniques - both right and wrong - are inherited and passed along to the next generation. Operators do not always possess the knowledge to question why something is done a certain way and, more important, to develop and implement operating practices that will save energy and, perhaps, minimize the potential for equipment malfunction.

In developing a distillation training program, we had a basic objective of instructing personnel in the principles of distillation equipment and system functions so that they would be able to perform their work more efficiently and with a greater sensitivity to energy conservation, safety and loss prevention.

A secondary objective, and just as important, was improved communication with supervisory and technical personnel.

Our basic approach and the results that we wanted to achieve were outlined to Doug Bishop of Learning Unlimited, Incorporated. He was asked to prepare a summary outline of the program contents and an estimated cost. After receiving a proposed program from Learning Unlimited, we assembled a group of personnel with disciplines in engineering - one of whom specializes in distillation, public relations, training and audio-visual aids for its review. Following some changes to meet our specific needs, Learning Unlimited was contracted to develop and deliver a distillation training program consisting of seven one-hour videotapes, trainee textbooks and instructor's manuals. The contract specified that Learning Unlimited would retain copyright privileges and that Hercules could copy all materials for company use.

As the text for each videotape was developed, we reviewed it for technical accuracy and general format - keeping in mind the varied backgrounds of our intended audience. After each script was approved, videotaping was carried out utilizing a TV broadcasting company's facilities and equipment. Polarized light techniques were employed to produce animated motions for improved concept of operating principles. Each completed tape was then reviewed for accuracy and format. If necessary, the tape was edited to produce a final product. Approximately three months, following the signing of the contract, were required to provide a complete, final package.

The completed program consists of seven one-hour videotapes plus associated manuals. There are two distinct sections, namely, Basics and Distillation. The Basics Section, consisting of three tapes, was designed to educate the trainee in engineering fundamentals - a prerequisite to understanding distillation. Examples of subjects included in the Basics Section are: The importance of distillation to the chemical industry; Definition of atoms, molecules, compounds and mixtures; Explanation of physical properties such as density, pressure, phase change, etc.; Fluids as related to laminar flow, turbulent flow and friction; Effects of heating materials as related to molecular action, phase change and pressure; Explanation of a temperature/heat graph, using ice, water and steam as examples; Methods of heat transfer; and Types of heat exchangers.

The four-tape Distillation Section introduces vapor pressure and relative volatility - basic concepts upon which distillation is based - and systematically takes the trainee from a simple water evaporating unit to a multi-effect evaporator and finally through a multi-stage distillation column. Using a benzene-toluene mixture, liquid and vapor flows plus compositions are calculated for both the rectifier and stripper sections. In conjunction with this,

operating lines and the equilibrium curve are established and the consequences of departing from theoretical conditions are stressed. Heat and material balances are introduced and the effects of sub-cooling distillate, internal reflux, product composition and feed location on tower efficiency are discussed.

Questions and sample problems follow each primary subject. A more comprehensive test is provided for each of the two major sections.

Completion of the videotapes and texts was the first step in reaching our intended audience. A brochure was developed which highlighted the program contents, the objectives of the program and stressed the fact that process energy savings extrapolate to an additional 33% fuel savings at the powerhouse. The brochures were distributed company-wide and offers were made to supply sample videotapes and textbooks for program evaluation.

To date, we have the DTP program in seven of our plants with formal instruction sessions getting underway. Since each plant has distillation operations peculiar to its particular operation, the training program is being manned by personnel from each plant rather than a single individual from corporate headquarters.

It is too soon to assess the value of this particular program; however, it was well received by a number of plant supervisors and technical personnel who served on assessment panels. There is one thing for certain. Operators who complete the distillating training program will have had the shroud of mystery lifted and be in a significantly better position to communicate his energy conservation ideas to supervision.

We recognize the importance of having personnel that are properly trained and thoroughly understand their specific jobs. Company sponsored training demonstrates that management has an interest in its employees and recognizes that a knowledgable person will contribute to corporate earnings. We do not intend to stop our energy conservation training and education program with boilers, turbines and distillation. At the present time, we are developing a similar program for drying - another energy intensive operation.

USE OF A CONVERSATIONAL COMPUTER PROGRAM IN OPERATOR TRAINING FOR IMPROVED ENERGY EFFICIENCY

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ABSTRACT

Energy efficient operation of process equipment requires attentive operation by well-trained personnel. Use of a computer simulation model together with a conversational computer program, which provides dynamic game playing opportunities for the trainee, has proven a very effective training tool. The programs have been used in plants and refineries, and they demonstrate the ability to develop rapidly within the Operator Trainee a real understanding of the variables affecting process performance.

Experience with a furnace firing computer training program is described. Using a time-share computer terminal, the Operator participates in a conversational training experience in which he is taught startup, routine operation, and to cope with operating problems on a gas and/or oil fired process furnace. Specific operator-oriented problems are encountered and solved by making control adjustments in the simulator program which has been developed. In using the program, the trainee is challenged to achieve or exceed firing efficiency goals set for the furnace. A variety of operating conditions are presented. As an extension of the success experienced with the furnace program, a new program has been developed simulating a crude oil distillation unit. The Distillation Column Operator training program is designed to facilitate an understanding of distillation principles and the effect on energy efficiency for the various product quality and yields achieved. The results of Operator acceptance of these programs is that a wider application of the principles computer simulator training to other industry processes is warranted.

INTRODUCTION

As you may be aware, petroleum refining and the chemical industry are two of the largest consumers of energy in the industrial sector. Shell Oil as a member of these industries consumes major quantities of fuel each day in the course of manufacturing chemical and petroleum products. By far, the largest category of fuel use for Shell occurs in gas and oil fired process furnaces, where more than 80,000 barrels per day of liquid fuel equivalent are burned each day. Proper combustion in these furnaces requires the attention of alert and well-trained operators to achieve maximum efficiency. The incentives for good operation are high. A single percentage point improvement in combustion efficiency in these furnaces represents nearly $8 million per year savings in fuel for our plant and refinery operations.

Over the years, schooling and training have been given to operators and supervisors. We have used in-house sessions as well as attendance at schools conducted by both furnace and burner manufacturers. Schooling in improved maintenance practices was also stressed.

In recent years, we have employed another system of training using a communications/educational approach. It is patterned after other successful computer teaching applications such as the "Management Games" program, where investment strategy precepts are taught through simulated inter-active market-manufacturing problems. Several years ago, Shell Canada used these techniques in an operator training program whi simulated corrosion in a crude distilling unit. T...

program whose trademark name is CORRISM was useful in developing operator understanding of corrosion control. This same training method has now been applied to the energy field. A furnace training program has been developed by Shell Canada Ltd. and is called a Furnace Operations Training Simulator with a trade mark acronym of FUROS. The program measures the operators ability to reestablish efficient furnace performance following major process changes and how to maintain furnace efficiency at the highest level during the course of a typical run.

The trainer consists of a mathematical simulation of a typical refinery process furnace which is accessed through the use of a timeshare computer terminal with cathode ray tube display and/or typewriter output. The program is fully conversational explaining the various steps and phases, and prompting the user at various points. The user response is to answer multiple choice questions and to enter appropriate values for variables he wishes to change when solving a problem. The furnace chosen for simulation is a 75 MM BTU/HR, four pass box-type heater with convection and radiant sections, capable of firing either gas or oil or a combination of both. The process fluid to be heated is a 26° API oil. A schematic outline of the furnace and control mechanism is shown in SLIDE 1. It should be noted that selecting a specific furnace design allowed simplification of the model since many parameters could be then fixed. The fact that the model represents a particular furnace does not detract from its ability to teach the general principles of good operating practice. SLIDE 2 depicts the operator input variables and process output information which constitute the training program. Control variables are indicated with an asterisk.

The simulator is designed to be used in four basic modules for training. These modules shown in SLIDE 3 are:

- ° Furnace Startup - Preparation
- ° Basic Operation - Case Studies
- ° Dynamics of Furnace Startup
- ° A Two-Year Furnace Run

FURNACE STARTUP

From a random order list of furnace startup activities, the trainee is required to put the necessary steps into the proper sequence, entering each step one at a time. After each entry, the program will indicate approval or if the step choice is incorrect, it will indicate the possible consequences of the operators action. In the case of a wrong action, the operator is prompted to choose again.

BASIC OPERATION

This simulator is designed to take the operator through a set of carefully designed cases so that he or she becomes familiar with many correct process adjustments. The trainee responds to changes which are either:

- changes in process conditions
  - Ambient air temperature
  - Furnace charge rate
  - Furnace charge temperature
  - Ratio of gas & oil to be fired
- or changes in furnace condition
  - Positive draft
  - Smoking stack
  - Excess air
  - High tube skin temperature
  - Furnace pulsating

For each of these off-normal conditions the operator learns to react by adjusting the furnace operation. As shown in SLIDE 4 there are four variables under his or her control:

- ° Primary air register
- ° Secondary air register
- ° Damper position
- ° Atomizing steam flow

The operator is given three attempts to correct the situation and re-optimize the furnace to a stated target. In the end, he or she is shown the optimal settings compared to their own, and the efficiency attained is compared to the target efficiency. It

should be pointed out that the target is set below optimum to allow the trainee to beat the computer.

DYNAMICS OF FURNACE STARTUP

As part of bringing the heater onstream, the operator is faced with starting at a low intake. To bring the operation up to design charge rate, the charge is increased in six stepwise increments. The operator must adjust variables to avoid a smoking stack, and maintain safe conditions while staying ahead of the changing feed rate and conditions. Once at design, the operator is given three opportunities to optimize efficiency. As before, the operator is subsequently given the information at optimum conditions.

TWO YEAR RUN SIMULATION

The previous modules prepare the trainee for a more challenging problem. Once the operator is quite familiar with the principles of furnace operation, he or she is given an opportunity in a period of an hour to simulate a two year run with the objective of maximizing crude intake and minimizing operating costs. Several operating parameters such as flue gas side fouling, coking and corrosion come into play as the run progresses. The operator is also given maintenance options such as soot blowing, decoking, retubing, etc., to offset these problems. Periodic process changes are made as the run progresses and the operator must re-optimize conditions after each change. Cost penalties are included for smoking stack or pulsating firebox. The total of all costs, both maintenance and operating, are accumulated, and a cost per barrel processed during the run is calculated.

The challenge of making the most efficient total run has proven a definite motivating factor as the operators compete with each other while training.

The FUROS program has had good operator acceptance and is now being used in ten refineries of Shell Canada and Shell Oil. Gulf Oil of Canada has also recently purchased rights to use the program. The operators are enthusiastic about this method of training since it gives them immediate reaction to their process changes. They have rapidly demonstrated the ability to develop a real understanding of the variables affecting furnace performance.

The secret of success in this approach to training seems to be embodied in the following criteria. The program should be SLIDE 5 :

1. Simple yet not trivial,
   and
2. Challenging but not discouraging.

We feel the authors of FUROS have achieved those objectives.

CRUDE UNIT SIMULATOR

Because of the success associated with the FUROS and CORROSIM program, Shell Canada has developed another program which is currently being tested. This program, known by the acronym CRUDSIM, is a mathematical simulation of a crude oil distillation unit including a furnace, heat exchangers, product streams, overhead system and circulating refluxes. A schematic of the simulator is shown in SLIDE 6.

As can be seen, the crude charge is distilled into a top and a bottom product as well as three intermediate boiling range products. The column has a top reflux and two intermediate circulating refluxes. The three side streams and the bottom product are stripped of light ends in steam strippers.

For each product various quality parameters are calculated as shown on the schematic. The trainee has the opportunity to manipulate seventeen operating variables which are indicated on the slide. The operator can see the effect on product quality and the cost of a change in each of these operating variables. The program demonstrates the interrelation and trade-offs in product yield and quality versus fuel and utility costs, which result from his or her actions.

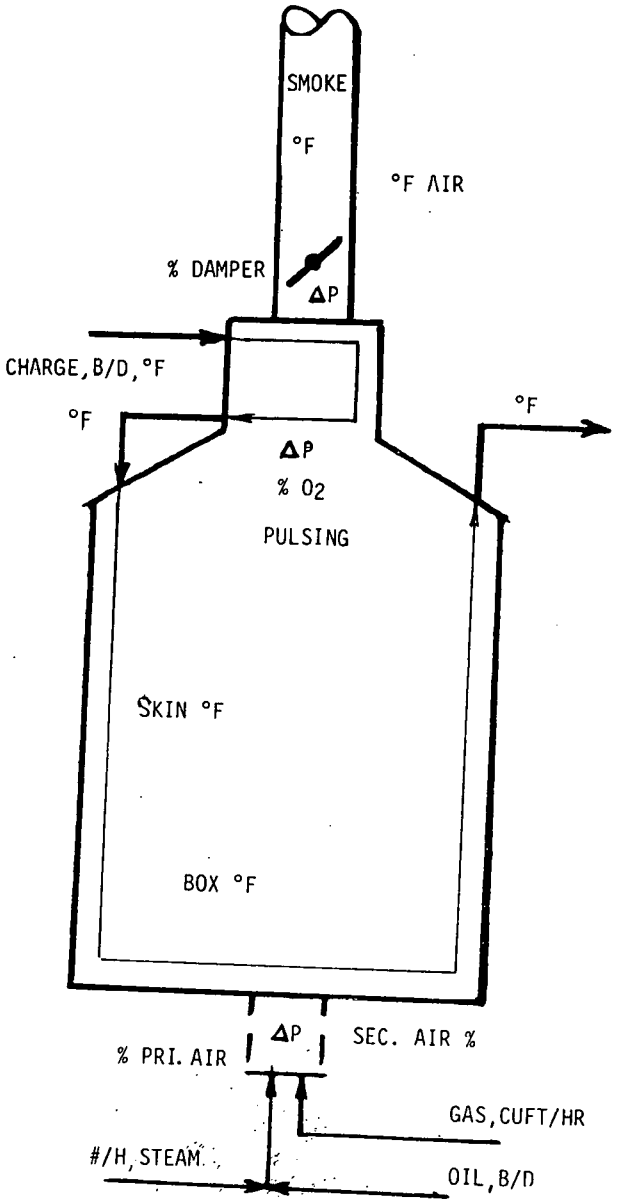
As with FUROS, training is accomplished through a series of operating cases in which process or equipment changes are made. Throughout, the operator is challenged to react properly and keep producti on specification safely and at minimum cost. SLIDE 7

depicts the categories of cases presented to the trainee. Shutdown and startup situations are created as well as various simulations of equipment failure and product or feed changes. The system is currently being tested in one of Shell Canada's refineries. As we indicated before, based on the experience with FUROS, there should be good operator reception of this latest program. It is hoped that operators can develop an understanding of distillation principles that will allow operation at minimum energy consumption consistent with the product quality requirement. Better understanding of the distillation process will allow quicker reaction to unit upsets and should result in more hours of operation at optimal conditions.

SUMMARY

The foregoing is a very brief description of a unique application of a training tool. The application of the computer simulator to real operator problems has produced some very rewarding results in terms of better equipment operation. It is gratifying to see how it has stimulated operator interest in doing the task more efficiently. That element of operator motivation is an essential cornerstone of any effective energy conservation program. We are pleased with the results obtained through use of FUROS and are looking forward to the availability of the crude distillation simulator. The possibility of extending this concept to other parts of the process industry is already being pursued in developing additional programs.

FUROS FURNACE SCHEMATIC



SLIDE 1 P&A 2/27/80

FUROS SIMULATOR DATA

OPERATOR ACTION VARIABLES

ALL SIMULATOR RUNS	TWO YEAR RUN
* DAMPER POSITION	DAMPER REPAIR
* SEC. AIR REGISTER	WASH CONV. SECT.
* PRI. AIR REGISTER	SOOT BLOWING
* ATOM. STM. FLOW	TUBE DECOKING
	RETUBING

OUTPUT DISPLAY

ALWAYS SHOWN	SHOWN ON DEMAND
AMBIENT TEMP.	DRAFT BELOW DAMPER
STACK TEMP.	CONV. SECT. OUTLET TEMP.
STACK SMOKING	CONV. SECT. DRAFT
FURN. FEED RATE	FLUE GAS O_2%
FURN. INLET TEMP.	COMBUSTION EFF. %
	DRAFT AT BURNER
	FUEL GAS FLOW
	FUEL OIL FLOW

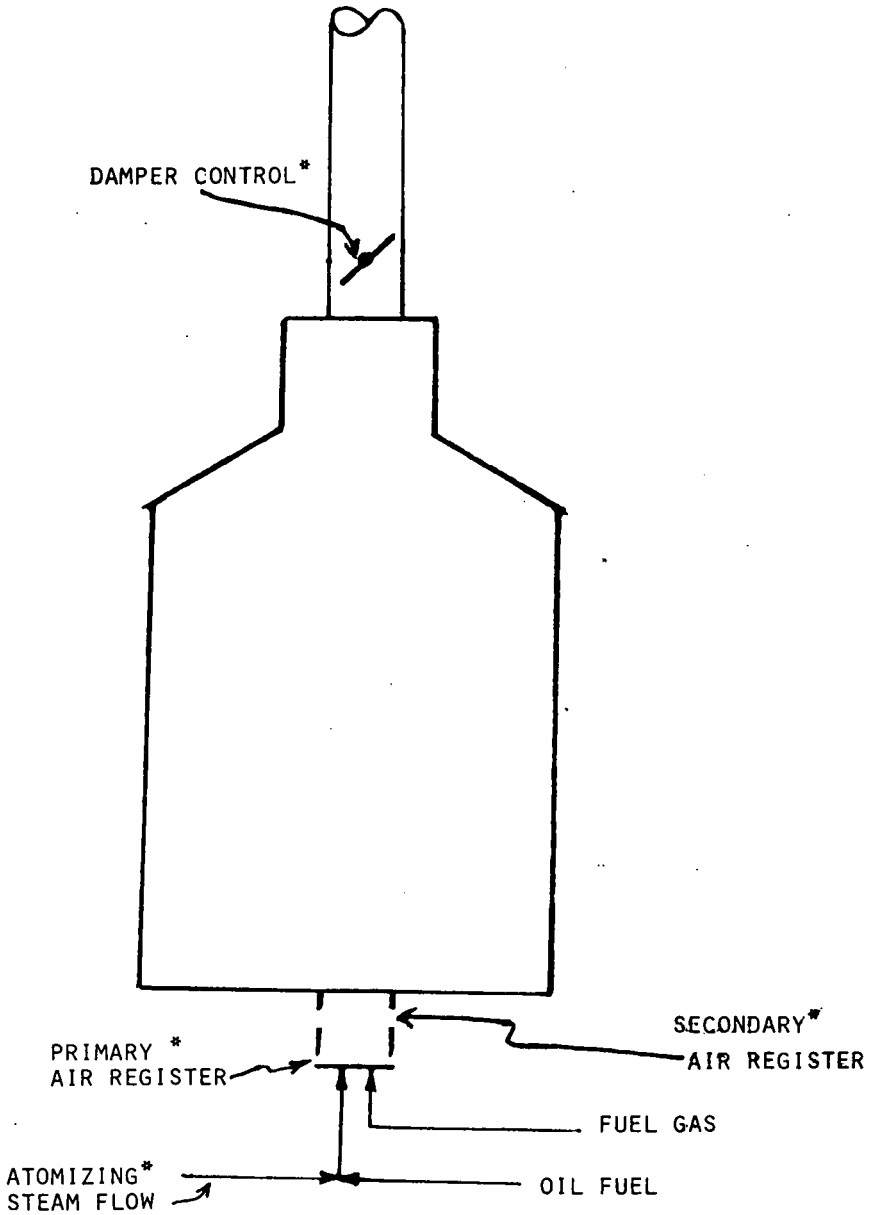
SLIDE 2 P&A 2/27/80

FUROS SIMULATOR MODES

- FURNACE START-UP - PREPARATION
- BASIC FURNACE OPERATION - CASE STUDIES
- DYNAMICS OF FURNACE START-UP
- TWO YEAR FURNACE RUN

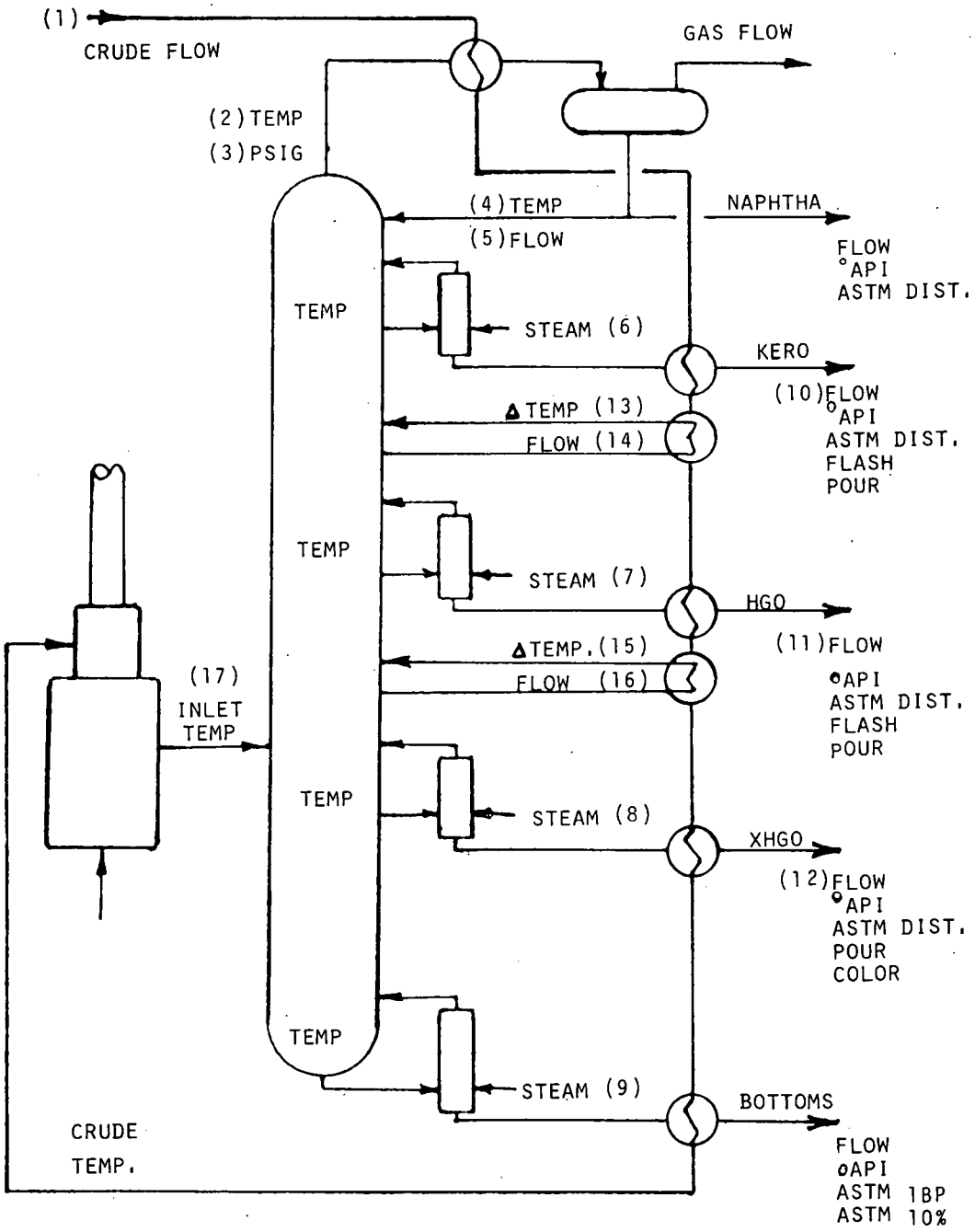
SLIDE 3 P&A 2/27/80

FUROS OPERATING
VARIABLES



SLIDE 4 P&A 2/27/80

CRUDSIM SCHEMATIC



SLIDE 6 P&A 2/27/80

CRUDSIM OPERATING CASES

STARTUP - ROUTINE

SHUTDOWN - ROUTINE

FAILURES
- ELECTRICAL
- COOLING WATER
- INST. AIR
- PUMP
- TEMP. CONTROLLER

LOSS OF CIRCULATING REFLUX

COLUMN FLOODING
- TOP
- MIDDLE
- BOTTOM

SPECIFICATION CHANGE
- INCREASE END POINT
- CHANGE POUR POINT

SLIDE 7 P&A 2/27/80

MAKING TRAINING EFFECTIVE

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Several years ago, a training session was being held at an electric generating plant in the Midwest. One of the subjects covered in the session was steamline drain traps. One of the trainees checked several of the steam traps when he went back on shift following the training session. He found that 2 of those that he checked had the bypass valves open, directly bypassing steam from the steamline to the condenser. He closed the bypass valves to put the traps into operation, as they should have been since the traps were operable. The condenser vacuum went up by one inch of mercury vacuum. The estimated savings as a result of this action were about $12,000 per week in coal costs!

A chemical production plant in the South used some boiler training materials covering combustion principles and control, boiler principles and operation, and boiler water treatment. During the course of the training, the operators found that they not only had been heating up the boiler too fast but also had not been using uniform operating procedures. They changed their rate of heatup and formalized their operating procedures. This is believed to have reduced maintenance outages and resulted in more safe, efficient operation. (A training retest in combustion and boiler principles one year later indicated a very high retention by all operators.)

The power production personnel at a paper mill in New Jersey used some boiler principles training materials on a self-study basis to meet the training requirements of the state for stationary engineers. Several of the operators passed state licensing tests in shorter periods of time on the job and with better test results than past licensees at the mill. This greatly increased operating flexibility by making it simpler to cover absentees and vacations.

What factors included in the training in each case cited made them so effective? Though included in varying degrees in the above examples, the factors remain something that you can do in your training programs. These factors are:

1) Making the training fit the trainees
   - Instructor must be a good communicator
   - Level of materials must be right for the trainees
   - Training must be job-related and be directly usable
2) Training must be supported
   - Supervisors must be strong supporters
   - Management interest must be strong and supportive
   - Training facilities must be good
3) Preplanning must be thorough and timely
   - Training should be discussed with supervisors early in planning
   - Training should be discussed with training/union early
   - Consider mixed groups (e.g., operators and maintenance personnel)
4) Follow up suggestions and complaints by trainees as soon as possible.

Though all are important, they will be applied in varying degrees if they are to make your training most effective.

A number of publications can be helpful to you in including in your training such factors as support, preplanning and followup. But making the training fit the trainee in one of the least explained, yet important, parts of the training. It, more than any other of the factors, led to the training successes described above. Let's discuss the methods we can use to make our training programs fit the trainees.

BEING A GOOD COMMUNICATOR

It is absolutely essential that the instructor be a good communicator if training is to be effective. To paraphrase General Robert E. Lee, a good instructor (leader, he said) must

- Know his "stuff"
- Know his trainees
- Know himself

If the instructor can truly say that he has these characteristics, then he is a good communicator.

Knowing Your "Stuff"

It is a tradition in many industries to consider that a person who knows his "stuff" is a person with a lot of operating experience. That not only is not always true, it certainly is not an automatic qualification to be a teacher. Among the reasons that experience is not an automatic qualification for being an instructor is the fact that little of the experience the average supervisor has is in any way related to communication with other personnel on a sustained basis. We think in terms of on-the-job training (OJT) as being a type of experience as an instructor. But is it really? And does OJT in any way qualify a person to stand in front of a group of people and explain a principle or process that just has not been taught by that experienced person? The experienced person may even have bad operating habits that were never picked up, but could potentially be dangerous or, at the least, not efficient.

Another potential problem with making experienced operating personnel as instructors is that of level of presentation. In many cases it is very easy, when you are closely involved in day-to-day operations, to forget that not everyone speaks your "language" as well as you do. It is very difficult to "get down to the right level" for some people. And if they don't even know that they are on too high a level, they are not about to consider getting the information in the right form to communicate well.

These criticisms of experienced personnel as teachers are not intended to impugn the experienced personnel in their normal job, but to point out that when considering them for an instructors position, their real job is not only to know what they are talking about but also to know how to communicate that knowledge. These should both be important in choosing a teacher rather than automatically assuming that experience is defined as knowledge of your subject and how to communicate it to others. (Also, don't forget that a lot of operating experience came into the classroom in the heads of the trainees.)

Knowing Your Trainees

A good instructor also needs to have a good know ledge of the trainees. He should know how they absorb information as well as what motivates them to do the job better. This means the ability to recognize ir dividual needs, viewpoints and motivating factors (each trainee - no easy task. Many instructors cannot remember being in the particular jobs of the trainees or may have never seen the worksite. Many believe that all problems can be solved by the "bludgeon" method and view the instructor's role as that of an authoritarian (as if they were running an old, one-room schoolhouse). Some people even believe that by teaching someone else they are jeopardizing their own job! (Think about how you could convince them otherwise. It isn't easy.)

To understand the trainees an instructor must communicate and listen to them - before the training, during the training, and after the training. Ask questions of them. Listen carefully to what they ask and, in some cases, what they are really asking. Ask them for criticism of the training. Ask them to make comments (since they often volunteer them, you probably won't have to ask). Try to put yourself in the shoes of the trainees, both on their job and in the classroom. The better you know them as individuals, the better you can teach them.

Knowing Yourself

The last piece of advice from General Lee was to know yourself. This means having the confidence in yourself and knowledge of your own strengths and weaknesses that will permit you to make the maximum use of the training time to communicate effectively and cause learning to take place. According to the Book of Lists, a survey of 3,000 U. S. inhabitants indicated that 41% felt speaking before a group was their biggest fear in life. Many people are afraid to be wrong and are easily embarrassed in front of a group. They feel that they must play a role instead of being themselves. They eventually will "forget their lines" and lose the confidence of their "audience." Just be yourself. If you can't tell jokes well, don't try. If you can, use it well. If you are not very dynamic yourself, find ways to make the training itself dynamic, such as by using a lot of visual aids, or guest speakers, etc. Do what you do best and find ways to support your weaknesses in teaching. The reward? More effective training.

LEVEL OF TRAINING MATERIALS

addition to the fact that the instructor must be a good communicator, the training materials must be communicative. Not only must the level of the materials be right for the trainees, but the materials must be job-related if we are to expect the trainees to feel motivated to learn and to use what they will learn. To understand the level of the materials, we must have some basic feel for the types of people we could have in the classroom as trainees.

Ways of Learning

To understand what is happening around them, whether in the classroom or in daily life, individuals use two basic methods of reasoning - deduction and induction. Deduction is going from the general to the specific. This type of reasoning is used in grade school subjects such as math and general science. Broad rules are used to explain particular cases, as in geometry rules or behavior of substances.

Induction is going from the specific to the general. This is using general rules that we develop from specific happenings. This is used in such grade school subjects as history or English grammar.

In reality, nothing is quite this simple since some individuals also look for other things in their reasoning, such as similarities ("That's just like..."), differences ("That's just like ... except ..."), rules ("We first cover ..., and then we cover ... and finally ..."), and combinations of each of these. The basic two methods of reasoning and all of the potential modifications must be considered in all phases of the training. But a compounding problem is that the instructor is also reasoning in one of these basic ways with one or more of the modifications. To get the materials in a form to teach all of the trainees in the training program, we have to think in terms of preparing the training materials to include all of the types of individuals in our thought process. But how can that be done?

We can include both basic types of reasoning in our materials very simply - by making all of the written materials have a start, a middle, and a stop. Even if the start is one or two sentences that put the training that follows in perspective with the job of the trainee and the rest of the training, it is what the deductive reasoner wants before the facts. (He is looking for the general beginning before the specific facts.) The inductive reasoner doesn't care about the beginning. He wants the facts and then to know what all of the facts mean relative to his job and the rest of the training. One or two sentences at the end is just what he is looking for to take him from the specific facts to the overall general conclusion. The interesting thing about this simple device (start, middle, stop) is that it works!

To handle the modifications of the basic two reasoning methods, we have to make sure that we include similarities and differences in our discussions and in the written materials. We should try to always present the materials in a pattern (e.g., components, then system, then controls, then operation) for the rule followers. And if we do all of these, we please the combination learner automatically. What we have to do, however, is overcome the fact that we might be one of these types and, as instructors, not look for the other modifications. With practice, we can do it.

Reading Level

We must be aware of the reading ability of our training participants before we prepare text materials and our presentations for them. A common response to the question of what the reading level of the trainees is is to say that they are high school graduates. Even though the U.S. is considered to have a fairly high literacy rate and a large proportion of the population is made up of high school graduates (65%), the average adult reading level is about grade 7. Among the many reasons for this fact is that reading is a practiced skill. Many sports pages have a reading level of 5, for instance, and many adult males only read that. If we continue to assume that the high school graduate can read at the grade 12 level, we will have little meaningful and effective training occurring, simply because the majority of the population will not be able to completely understand the training materials.

Best-selling novels range from a reading level of 10 to about 12. Only about 40% of the U.S. population could handle that level. Many scientific texts, articles, and equipment descriptions from manufacturers

are written on levels of 15 or above, with only about 5% of the U.S. population capable of handling them. The vast majority of the materials that we have available to use in training in technical fields is written on a high level - too high a level to use them in our training. But why?

The reason is that they were never intended to be used as training materials in the first place! Most were intended to describe new inventions or concepts to other highly trained members of their fields. With obvious pride in their accomplishments and with the knowledge that they would likely be judged (in their own minds, at least) by the way they explained what they had invented or discovered, they carefully and elaborately worded their descriptions. (Let's don't single them out, since we all do this sort of thing.) Thus, they are not appropriate for training. Yet we use them all of the time as part of our training programs even though less than 5% of our population can handle them.

To understand what we can do to get the right reading level, let's look at how to measure reading level. One method includes measuring in a sample of written material the number of words, the number of sentences, the number of extra syllables (greater than one per word) in the words, and the number of personal references. The greater the number of words per sentence and the greater the number of extra syllables, the higher the reading level. But the greater the number of personal references, the lower the reading level. One general method of measuring the reading level is to select a sample that has at least 100 words in it and then do the following:

1) Count the number of words (W).
2) Count the number of sentences (S).
3) Count the extra syllables (E).
4) Count the personal references (P).
5) Divide W by S.
6) Subtract P from E.
7) Add 2 0's after E-P. Same as (E-P)X100.
8) Divide the result from Step #7 by 2 times W.
9) Add the results of Steps #5 and #8.
10) Divide the result of Step #9 by 3.
11) Subtract 2 from the result of Step #10. This is the reading level of the sample.

If you try this on the paragraph just before the steps, you will find a reading level of 11.5 (W=117 S=5, E=60, and P=2). Notice that lowering the number of words (W), and number of extra syllable (E) will lower the reading level. Instead of saying "One method includes" the phrase "One way is" has 2 fewer extra syllables, though the number of words in the same. The reading level could also be lowered by increasing the number of sentences (S) and by increasing the number of personal references. Note that increasing S decreases the number in Step #5. Also increasing P decreases the number in Step #6. Both decreases will decrease the reading level.

In addition, we can do several other things to make the reader <u>want</u> to read training materials more, which has the <u>effect</u> of reducing the reading level. These include:

- Making paragraphs shorter
- Indenting lists to make them easier to read
- Telling readers why the information is important to them

Again, the object is to reduce the reading level from the level we find in most technical materials available to us to a level that more closely matches the ability of our trainees.

But how far down in level should we go? Won't our trainees start to feel we are "talking down" to them if we use lower reading levels? The answer is that we should go lower than one might think, but no lower than about 6 or 7. The author wrote a pamphlet on metric conversion and intended it for grade 4 schoolchildren. After asking 4 adults (2 high school graduates and 2 college graduates) to read the pamphlet, none noticed that the reading level was grade 4! Why? Because the readers had no knowledge of the subject, having never been exposed to metric units. They wanted to understand and didn't realize the reading was so easy <u>because it was not getting in the way of their understanding</u>. In many cases, the materials should start, for the average process industry trainee, at about grade 7 or 8 and work upward through the text materials to about 10. Remember that the trainees are practicing their o— skill in reading as they are going through the te This pattern has worked well in several industries.

JOB-RELATED MATERIALS

nally, of all of the ingredients in successful training programs such as the examples cited in the beginning, the most essential is that the materials must be job-related. To do that the instructor must understand the job requirements, what the conditions are on the job, and what problems the trainee faces on that job. This requires talking with the trainees and their supervisors, observing what is done on the job, and making sure you explain why things are done as they are. If you can place yourself in the shoes of the trainee as you are preparing the training, it helps you a great deal in including the necessary job orientation to the training. By making the training job-related, we can influence the trainee to motivate himself to learn the information well enough that he can directly apply it, with enthusiasm, to his daily functioning on the job. The most pleasant feeling in the world is to have a trainee tell you after a class that he had worked around a certain piece of equipment for a long time and never really knew what it did or what he was doing when he operated it.

By doing all of the things we have covered, the training programs we are involved with can become more efficient and effective, and we make more money as a company. And since so many of the things are quite simple compared to many things we are already doing, we do not have to do much extra to get the increased benefits of the good training. Try some of them. You'll see!

A PRACTICAL APPROACH TO PROCESS ANALYSIS AND IMPROVEMENT FOR ENERGY CONSERVATION

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ABSTRACT

A practical approach to process analysis and improvement for energy conservation has been developed by establishing the required technical basis, which arises from the first and the second laws of thermodynamics. As the tool for process analysis for the present purpose, the so-called heat availability diagram has been used. It is useful to show visually the status of energy utilization, the loss of available energy due to irreversibility of process, and the bottleneck on improving energy utilization. Several practical examples are taken up for illustrative purposes.

INTRODUCTION

In order to cope with growing energy problems, the need to conserve energy has been widely recognized. This aspect has resulted in a greater need than ever to understand how energy is used in a process system. Many process systems in the chemical industry are essentially energy-intensive systems, and they can be treated as networks of energy flow. Due to the complexity of the process system consisting of many subsystems, it is difficult to understand quantitatively how the system has been designed in view of energy conservation.

Many efforts have been made for conserving energy, and a great amount of literature has been published. Each has its own merits in shedding light on where and how energy is used. Some engineering decisions for process improvement, however, may often be made under a false impression given by a process analysis that does not discriminate the qualities of energy involved. It is important to establish a sound technical basis for energy conservation in a process system. Recently the authors' group has developed a practical approach to process analysis and improvement for energy conservation by establishing the required technical basis, which arises from the available energy concept in thermodynamics. As shown elsewhere [1], it has been confirmed that the available energy concept is useful in the analysis and synthesis of heat exchange systems.

The so-called heat availability diagram has played a central role in analyzing as well as synthesizing the heat exchange systems. The approach has been extensively applied to heat integration in distillation systems [2] [3] and chemical processes [4], and to steam-power system design [5]. This paper aims to summarize the authors' recent works. After describing the available energy concept as the required technical basis, the method of process analysis for surveying the bottlenecks concerned with energy utilization in a process system is given by using the heat availability diagram based on the available energy concept, and it is shown that improvement of the process system is evolutionally carried out as the result of the debottlenecking on the heat availability diagram. Several practical examples for process analysis and improvement are taken up for illustrative purposes.

REQUIRED TECHNICAL BASIS

There are three basic constraints applied to any process system design and operation in the chemical industry [6]:

(1) The conservation of material, that is, the conservation of the amounts of chemical elements.
(2) The conservation of the sum of all energies of the system and its surroundings.
(3) The production of entropy, which must always be positive.

The first constraint restricts the overall composition of feedstocks and products. It may sooner or later require industrial recycling of chemical elements because one lives in a closed system. The second and third constraints are derived from thermodynamic concepts and are concerned with the flow of energy and its degradation in any process system, respectively. Each of them is as stringent as the principle of mass conservation since the process system is also a system of energy conversion.

The thermodynamic concepts have the two basic properties of "energy", which arises from the first law, and "available energy", which arises from the second law. The available energy of a system is defined as the maximum useful (net) work which could be obtained by bringing the system (which is enclosed and allowed to communicate only with the surrounding atmosphere) to its dead state - its equilibrium state at the temperature and pressure of the atmosphere [7]. The available energy concept was given by Gibbs and later developed further by Keenan [7]. In steady-state flow system, the available energy of a mixture, where such factors as kinetic and potential energies are neglected, is defined as follows:

$$A = \int_{\text{dead state}}^{\text{state}} dA = \int_{\text{dead state}}^{\text{state}} (dH - To\, dS)$$

$$= H - ToS - (Ho - ToSo)$$

$$= H - ToS - \Sigma X_j \mu_{jo} \qquad (1)$$

where the dead state is the state of zero available energy. If the mixture behaves ideally, Equation (1) is written as follows [8]:

$$A(T,P,\bar{X}) = \Sigma X_j [A_{j,t} + A_{j,p} + A_{j,c}] \qquad (2)$$

where

$$A_{j,t} = \int_{To}^{T} [1 - \frac{To}{T}] Cp_j\, dT \qquad (3)$$

$$A_{j,p} = RTo \log \frac{P}{Po} \qquad (4)$$

$$A_{j,c} = H_j(To) - ToS_j(To, X_j Po) - \mu_{jo} \qquad (5)$$

The physical available energy ($A_{j,t} + A_{j,p}$) given by Equations (3) and (4) exists because the system is at a pressure different from Po and/or a temperature different from To, and is equal to maximum (net) useful work that could be obtained by bringing the system (which is enclosed but not isolated) to Po and To, while maintaining unchanged its physical and chemical composition. The chemical available energy ($A_{j,c}$) given by Equation (5) exists because the physical and chemical composition throughout the system is not identical to that of the dead state. Thus, the available energy is arbitrarily divided into two parts - physical and chemical - and furthermore the physical available energy is similarly divided into thermal available energy ($A_{j,t}$) associated with temperature change and mechanical available energy ($A_{j,p}$) associated with pressure change.

From above-mentioned definition, when a steady-state flow system changes from a State 1 to another State 2, the available energy change is given by

$$\Delta\dot{A} = \dot{M}_2 A(T_2,P_2,X_2) - \dot{M}_1 A(T_1,P_1,X_1) \qquad (6)$$

$$\Delta\dot{A} = - W_{min/max}$$

$$= - W + (W_{min/max} - W)$$

$$= - (W + I) \qquad (7)$$

where $W_{min} < 0$, $W < 0$ for minimum work input, $W_{max} > 0$, $W > 0$ for maximum work output, and then $I = W_{min/max} - W \geq 0$. Equation (7) is a quantitative definition of irreversibility of a process which the system-atmosphere combination executes. The irreversibility equals the loss of available energy which can be defined by the available energy balance. The first law cannot reflect the loss of available energy because energy is always conserved. The second law reflects the loss associated with a change of grade of an energy quantity. Unlike energy, the available energy is not conserved and any degradation by friction, or by heat transfers through a temperature difference, results in the loss of available energy. Maximum work output (W_{max}) or minimum work input (W_{min}) could be obtained if the process were completely reversible, and then there is no loss of available energy. Since every real process, however, is irreversible, available energy is in fact lost, as is reflected by the irreversibility which must always be positive. This fact shows that a sound technical basis for energy conservation is to minimize the loss of available energy by approaching the process to a reversible one.

In the process system, the major irreversible process is the heat transfer process through a temperature difference. It is important to recognize that temperature decrease is directly concerned with the degradation of thermal energy. For the process system with given feedstocks, specified products and no pressure change with friction, Equation (3) plays an important role because Equations (4) and (5) are constant. From Equations (2), (3) and (6), the

available energy change of the system is given by

$$\Delta\dot{A} = \dot{M}\int_{T_1}^{T_2} \Sigma X_j Cp_j \left[1 - \frac{To}{T}\right] dT$$

$$= \int_{Q_1}^{Q_2} \left[1 - \frac{To}{T}\right] dQ \qquad (8)$$

It is possible to make a graphical presentation of the available energy by plotting the Carnot efficiency, $(1 - \frac{To}{T})$, against heat flow, Q, which is called a heat availability diagram. On the heat availability diagram, as shown in Figure 1, the area under a line between State 1 and State 2 corresponds to the available energy change. Figure 2 shows the heat availability diagram for the process system as shown in Figure 3 [9]. Figure 2(a) shows the heat availability lines for two heat source streams. Figure 2(b)

Figure 1.

A Heat Availability Diagram

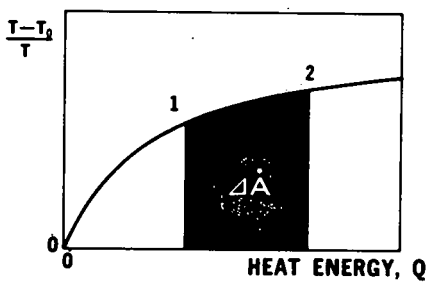


Figure 2.

The Heat Availability Diagram For The Process System

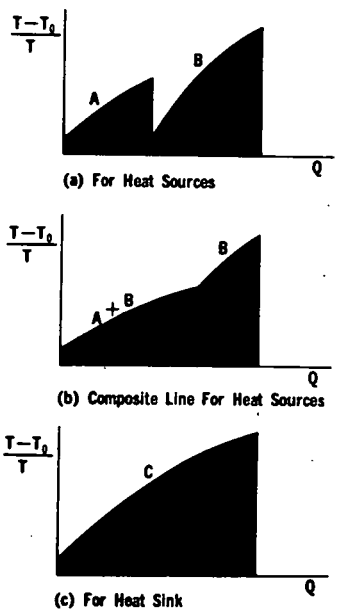
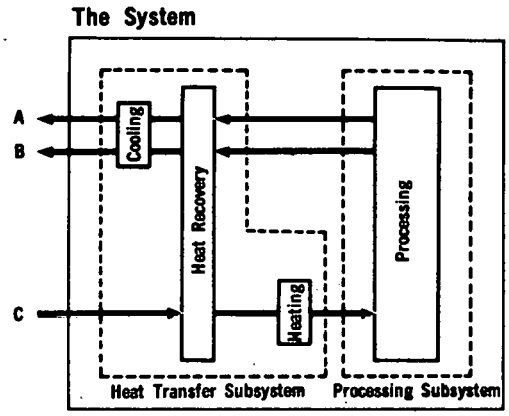


Figure 3.

A Schematic Process System



Heat Sink Stream

C : Feed

Heat Source Streams

A : Product A

B : Product B

can be derived by taking the stream segments with same temperature level and drawing the corresponding composite line for heat source streams. Figure 2(c) shows the heat availability line for a heat sink stream. A detailed explanation of constructing the composite line has been given elsewhere [1]. By the available energy balance (Equations (6) and (7) with W=0) in the processing subsystem, the difference (I_{PR}) between the rate of available energy into the subsystem by the heat sink stream and the rate of available energy out of the subsystem by the heat source streams shows the loss of available energy in the subsystem. As shown in Figure 4, the enclosed area between the two lines corresponds to the loss of available energy in the processing subsystem. To

Figure 4.

The Loss of Available Energy For The Processing Subsystem

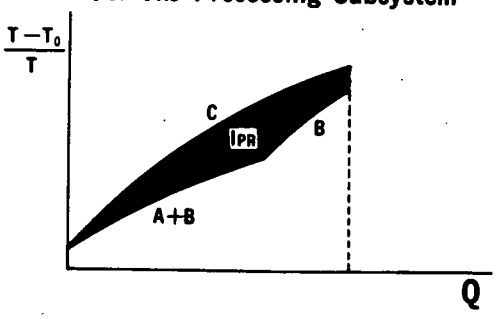
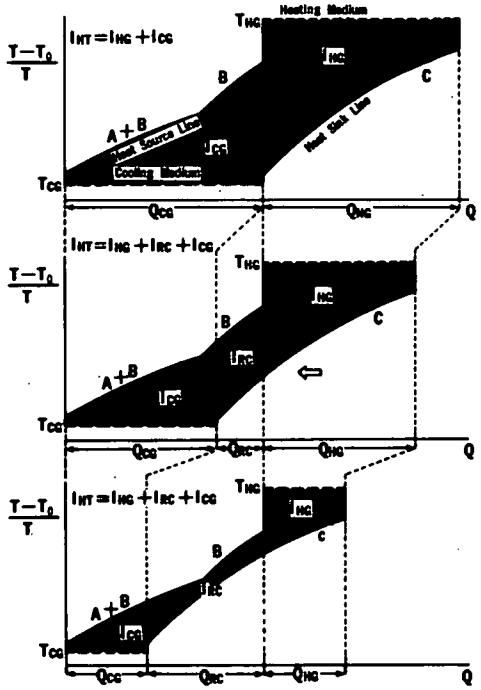


Figure 5.

The Loss Of Available Energy For The Heat Transfer Subsystem



find the conditions of heat recoverability, the heat sink line is set up as shown in Figure 5 [9]. Figure 5(a) shows that the system does not recover any heat. The heat sink (feed) stream is heated by a heating medium, and the heat source (product) streams are cooled by a cooling medium. By the available energy balance (Equations (6) and (7) with W=0) in the heat transfer subsystem, the difference (I_{HT}) between the rate of available energy of heat source streams including the heating medium and the rate of available energy of heat sink streams including the cooling medium shows the loss of available energy in the subsystem. The enclosed area shown in Figure 5 between the two lines corresponds to the loss of available energy in the heat transfer subsystem. Figures 5(b) and (c) show that the loss of available energy is decreased by increasing heat recovery (Q_{RC}). The total loss of available energy in the process system is obtained by

$$I = I_{PR} + I_{HT} \qquad (9)$$

Minimization of the available energy loss is achieved by minimizing the area between the two lines. Thus, the heat availability diagram based on the available energy concept can be effectively used to know intuitively the loss of available energy in the process system.

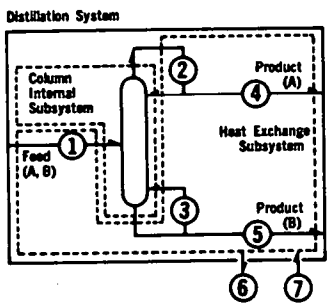
PROCESS ANALYSIS

In addition to the conventional analysis which uses only the energy concept, much attention has been given to evaluating the quality of energy by the analysis based on the available energy concept. Among several ways of applying the available energy concept, the practical usefulness of the "heat availability diagram" has also been recognized by the authors' experiences. From Equations (7) and (8), the loss of available energy associated with heat is given as the function of operating temperatures of the process system. The operating temperature are often given as the function of operating pressures and/or components of raw materials, products, etc. For the process system with given raw materials, specified products, and no pressure change associated with friction, minimizing the loss of thermal available energy can be achieved by a combination of changing operating pressures associated with operating-temperature changes and increasing heat recovery as shown in Figure 5. It is recognized that measures for achieving minimization of the available energy loss by changing operating variables are design techniques for energy conservation.

To make clear the effects of operating variables on the loss of thermal available energy, a distillation system shown in Figure 6 is taken up as an example.

Figure 6.

A Binary Distillation System



Heat Sink Streams

1 Feed
3 Stream To Be Reboiled
6 Cooling Medium

Heat Source Streams

2 Stream To Be Condensed
4 Top Product
5 Bottom Product
7 Heating Medium

Figure 7.

Heat Availability Analysis Of Double-effect Distillation System

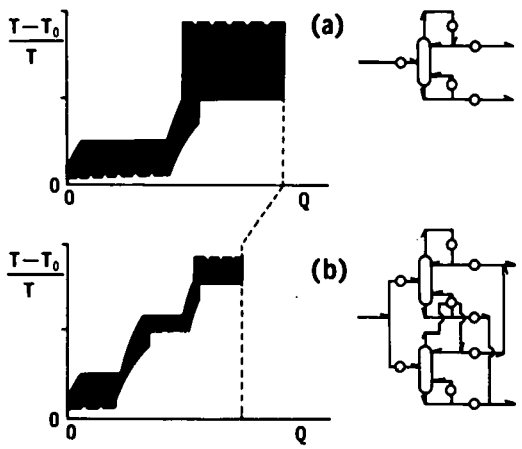
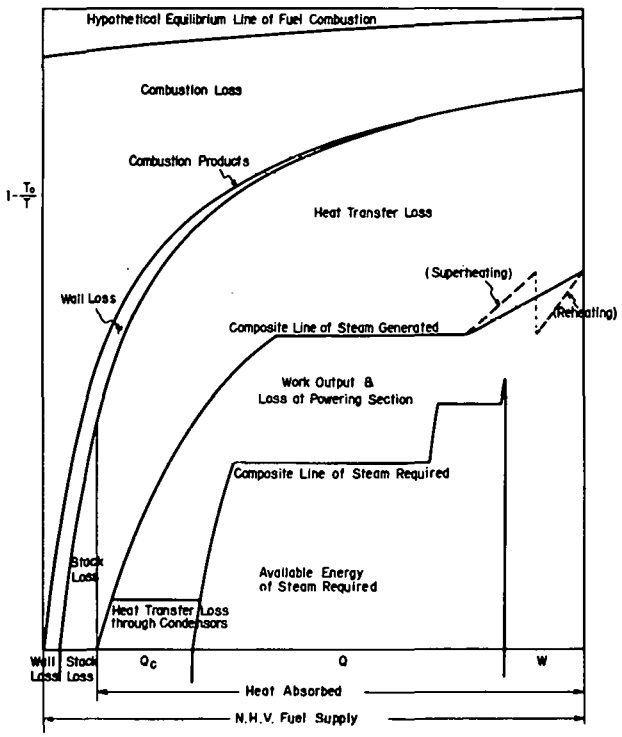


Figure 8.

Heat Availability Analysis of a Typical Steam-Power System



The results of the analysis by using heat availability diagrams are shown in Figure 7. Figure 7(a) shows the conventional distillation system and its heat availability diagram. Figure 7(b) shows the double-effect distillation system and its heat availability diagram. Compared to the former system, the latter system gives a clear decrease in the enclosed area between the two lines which shows the loss of available energy associated with heat transfer, and the amount of heat supply by the heating medium. This means that raising the operating temperature of a part of the condensing stream in Figure 7(a) is achieved by raising the corresponding partial operating-pressure as realized by dividing the distillation column into two columns in Figure 7(b). As the result of this operation, heat exchange between the condensing stream and the reboiling stream is realized. A detailed description of heat availability analysis for the distillation system has been given elsewhere [2].

As another example showing the practical usefulness of the analysis by using heat availability diagram, a typical steam-power system is taken up. The results of the analysis are summarized in Figure 8. This figure shows the heat availability diagram for the steam-power system, which represents available energy change of streams with respect to their temperature or pressure change. The area below each line implies the available energies to be discharged by each energy carrier. The losses of available energy through combustion and heat transfer processes are shown by areas between two lines. The area at the powering section contains the work output and the mechanical loss of available energy. The target of energy conservation for the steam-power system is to minimize fuel consumption for given demands. This corresponds to minimizing the loss of available energy under material and energy balances. From the viewpoint of minimizing the loss of available energy on the heat availability diagram, a set of instructions for improvement of the steam-power system can be evolutionally obtained. A detailed description of the analysis for the steam-power system has been given elsewhere [5].

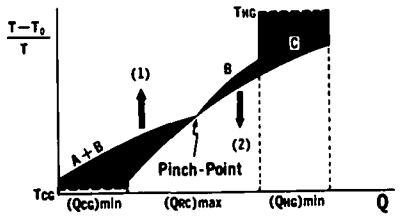
PROCESS IMPROVEMENT

The results of the foregoing analysis show where a bottleneck exists, and improvement of process systems is started by eliminating bottlenecks sequentially one at a time from the viewpoint of energy conservation. This can be placed in process synthesis for determining a set of alternative system-structures which achieve present objectives. A series of bottlenecks in the process system is systematically found by the analysis using a heat availability diagram, and a set of alternative systems is evolutionally obtained as the result of debottlenecking by using

the same diagram. As shown in Figure 5, the area enclosed by the two lines can be decreased by shifting the heat availability line for the heat sink stream to the left on the diagram. When the two lines contact as shown in Figure 9, no more heat can be recovered without changing condition or structure of the system. The point where the two lines contact is called the pinch-point. Since there is no temperature difference at the pinch-point, the heat exchanger area is infinite. The pinch-point associated with the temperature difference shows a thermodynamic constraint on heat recovery. Further heat recovery can be realized by eliminating the pinch-point.

Figure 9.

Pinch-Point Finding And Its Elimination For The Process System



As pointed out in Figure 9, pinch-point elimination can be achieved by the following operations on the diagram.

(1) For the composite line of heat source streams, raising the temperature level of the left-side segment above the pinch-point.

(2) For the composite line of heat sink streams, lowering the temperature level of the right-side segment below the pinch-point.

Changing the temperature level is performed in practice by varying operating conditions such as pressure or temperature of the heat sink or source streams. After eliminating the pinch-point, the composite heat sink line can be shifted. These steps are iteratively implemented by the following three basic operations.

(1) An operation f_p is to change pressure of the streams which causes a temperature change on the composite lines or their segments. The operation of f_p for the composite lines leads to decreasing the loss of available energy in the high-temperature region and increasing it in the lower-temperature region. Although this operation requires an increase in the amount of energy input, it is compensated by the following operation f_E, described below.

(2) An operation f_T is to change temperature of a segment of the composite lines without pressure change.

(3) An operation f_E is to shift the composite heat sink line to the left. This makes it possible to recover heat.

By repeating iteratively each set of operations (f_p and f_E), and (f_T and f_E) on the composite lines or on their segments, a series of heat integration systems is evolutionally obtained as the result of eliminating the pinch-points that occur in every repetition. The loss of available energy corresponding to these systems decreases monotonically along the repetitive operations, but the operations increase the complexity of the system.

As an example of improvement of a process system by applying these basic operations, the distillation system shown in Figure 6 is taken up. Figure 10

Figure 10.

Possible Systems Generated By One Step Operation On A Binary Distillation System

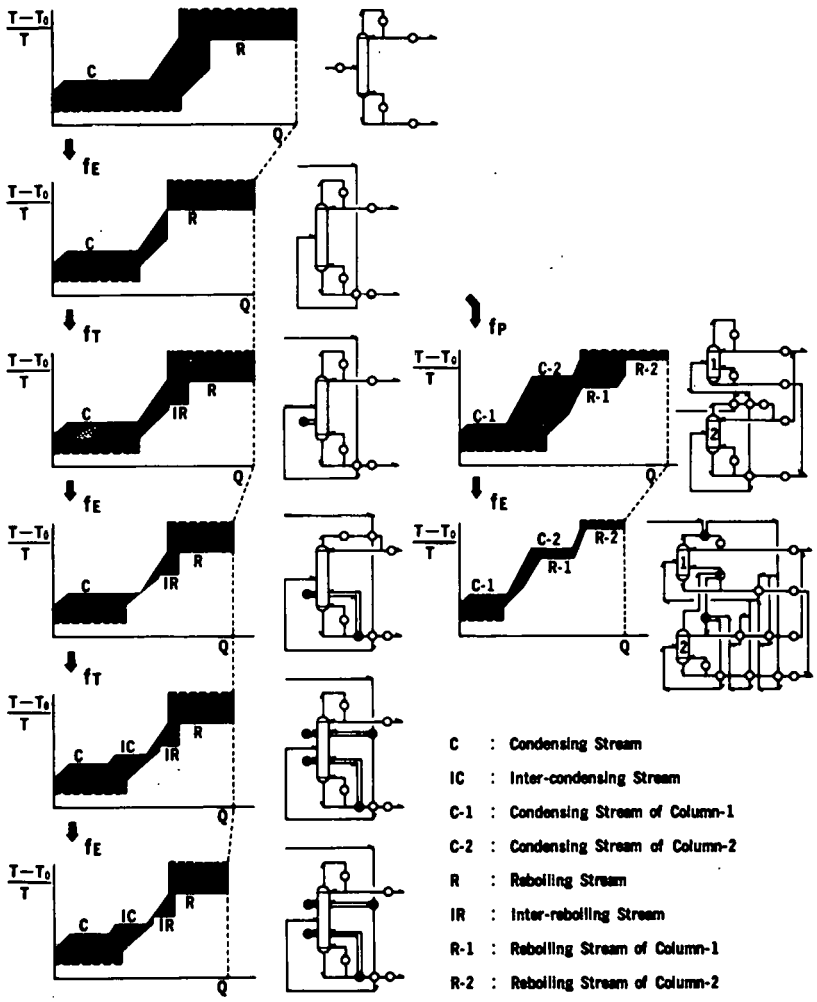
Operation	Applied On The Composite Lines			Derived Techniques
f_P For Lines	R	SI & SO	:	Pressurized Tower
	L	SI & SO	:	Depressurized Tower
f_P For Segments	R	SO	:	Vapor Recompression
	L	SI	:	Bottom Liquid Flash
	R	SI & SO	:	Multi-effect Distillation
f_T For Segments	R	SO	:	Inter-condenser, Sloppy Separation
	L	SI	:	Inter-reboiler, Sloppy Separation
	R/L	SI & SO	:	Inter-condenser/Inter-reboiler

Legend
SI : The Composite Heat Sink Line
SO : The Composite Heat Source Line
R : To Raise
L : To Lower

shows the energy conservation techniques of the distillation system associated with these basic operations. The iterative repetition of the operations can be graphically shown in Figure 11, in which the heat availability diagram is shown with the operations applied in every step. Starting from the original distillation system without any heat integration, two distillation systems are synthesized. One is a double-effect distillation system and the other is a distillation system with an interreboiler and an intercondenser. A detailed description of heat integration in the distillation systems by a thermodynamic approach has been given elsewhere [3].

Figure 11.

Iterative Repetition Of The Operations



As another example of process improvement, a basic chemical process system shown in Figure 12 is taken up. Starting from an initial structure of the system without heat integration, a series of modified systems with improved heat utilization is evolutionally developed by using the heat availability diagram. Firstly, heat integration is carried out independently for the reaction system and the separation system. Figures 13 and 14 show the heat availability diagrams with a series of f_E operations for each system and the corresponding modified systems with improved heat utilization. Secondly, the system structures obtained for each system with heat integration are simplified from the viewpoint of practical design [1]. Finally, heat integration between reaction and separation systems is carried out by engineering judgements leading to appropriate solutions regarding operability, operating and investment costs, etc. The result with appropriate heat integration is shown in Figure 15. This system has no need of any heating medium owing to heat integration between reaction and separation systems and is not very complex. A detailed description of heat integration in chemical processes by a thermodynamic approach has been given elsewhere [4].

Figure 12. A Basic Chemical Process System without Heat Integration

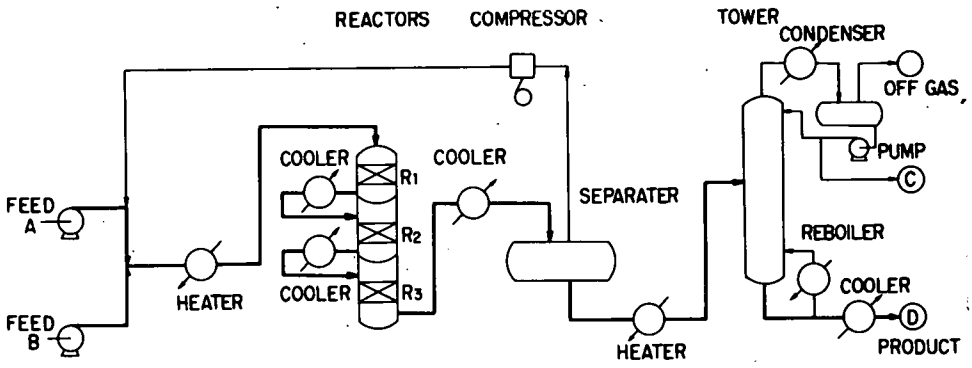


Figure 13.

Heat Availability Diagram for the Reaction System and its System Structure Derived

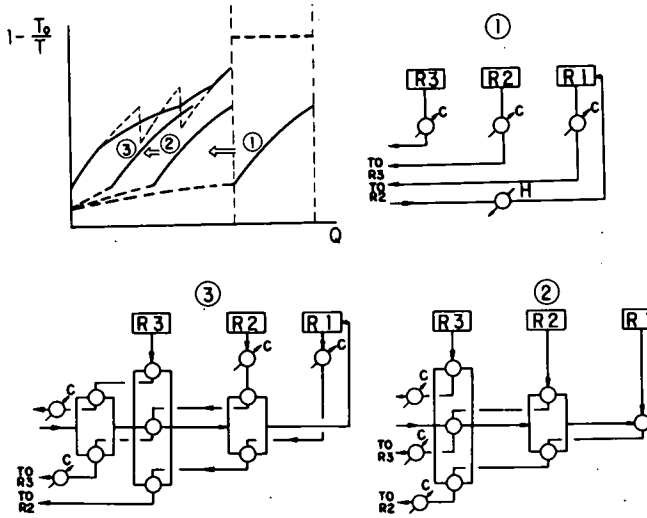


Figure 14.

Heat Availability Diagram for the Separation System and its System Structure Derived

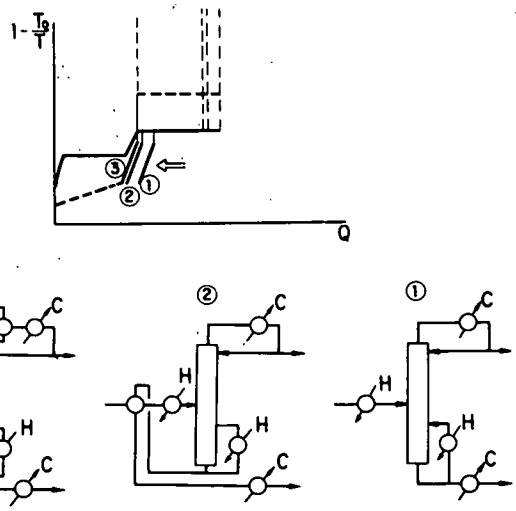
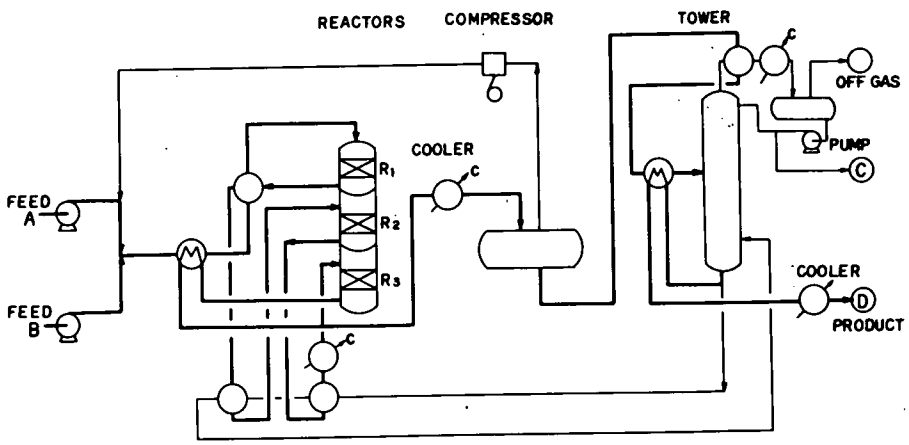


Figure 15. A Process Flow Scheme with Heat Integration



CONCLUDING REMARKS

The advantage of utilizing heat availability diagrams as the tool for process analysis is to visualize the status of energy utilization, the loss of available energy due to irreversibility of process and the bottleneck concerned with energy utilization in a process system. As the result of debottlenecking operations on the heat availability diagram, improvement of the process system can be evolutionally carried out.

From a more practical viewpoint, it is convenient to show visually the approach temperature on the temperature - heat flow (T-Q) diagram, and calculate the loss of available energy, separately. Though the area enclosed by the two lines on the T-Q diagram does not give an exact value for the loss of available energy, within a certain allowable range the loss of available energy can be approximated by a linear relationship. Therefore, the T-Q diagram can be more practically used as the tool for process analysis and improvement.

Acknowledgment

The authors are indebted to Chiyoda Chemical Engineering and Construction Company for permission to publish this paper. They express their appreciation of assistance rendered them by M. Nishio, K. Niida and J. Itoh for development of the present approach.

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Nomenclature

$\dot{A}$	:	Available energy per unit time
A	:	Available energy per mole
Cp	:	Specific heat
H	:	Enthalpy
I	:	Irreversibility
$\dot{M}$	:	Mole per unit time
P	:	Pressure
Q	:	Heat (Thermal energy)
R	:	Universal gas constant
S	:	Entropy
T	:	Absolute temperature
W	:	Useful work
$X,\bar{X}$	:	Mole fraction, $\bar{X} = (X_1, X_2, X_3, \ldots, X_{n-1})$

Greek Symbols

μ	:	Chemical potential

Subscripts

0	:	Dead state where is the state of zero available energy
1	:	State 1
2	:	State 2
c	:	Chemical
j	:	jth constituent
p	:	Pressure
t	:	Thermal

AN APPROACH TO EVALUATING EQUIPMENT-EFFICIENCY POLICIES

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ABSTRACT

The National Energy Conservation Policy Act of 1978 authorized studies of several types of industrial equipment to evaluate the technical and economic feasibility of labeling rules and minimum energy efficiency standards. An approach to the evaluation of these and related policy options is under development. The approach includes equipment classification and characterization, market characterization, and the subsequent evaluation of effectiveness and costs of the policy options. Technical, economic, and marketing data obtained with the cooperation of industrial groups, such as trade associations, permit an objective evaluation of policy impacts.

INTRODUCTION

The National Energy Conservation Policy Act of 1978 (NECPA) [1] mandated the Department of Energy (DOE) to evaluate electric motors and pumps to determine standard classifications with respect to size, function, type of energy used, and method of manufacture; and to determine the practicability and effects of requiring electric motors and pumps to meet performance standards establishing minimum levels of energy efficiency. The Act also authorized similar studies of fourteen other types of industrial equipment, namely, compressors, fans, blowers, refrigeration equipment, air conditioning equipment, electric lights, electrolytic equipment, electric arc equipment, steam boilers, ovens, furnaces, kilns, evaporators, and dryers.

The content of these studies was stipulated by NECPA to include identification of significant factors that determine energy efficiency, including hours of operation per year and average power consumption at normal use and at full capacity; estimation of current and future equipment population profiles; estimation of the potential for improvements in energy efficiency that are both technologically feasible and economically justified; and estimation of likely increases or decreases in energy efficiency and total energy savings likely to result from implementation of labeling rules and energy efficiency standards.

The standard classifications of industrial equipment referred to in NECPA were stipulated to include two elements: definition of the equipment contained in each class; and characterization of the equipment and its general use. Beyond these stipulations, however, the Act was silent as to the methodology to be used in performing the studies.

In response to the requirements of NECPA, Argonne National Laboratory has been engaged in the development of an approach to the evaluation of possible governmental policy options that would encourage industrial energy conservation. The initial focus of this approach has been on the particular policy options targeted for evaluation in NECPA, that is, labeling rules and performance standards establishing minimum levels of energy efficiency. These stated policy options focus rather narrowly on the intrinsic energy efficiency of industrial equipment. We intend, however, to expand the policy analysis approach to include the evaluation of other possible policy actions with the goal of conserving energy in industry. For example, for some types of equipment, performance standards might more feasibly be expressed in terms other than minimum levels of energy efficiency *per se*. The evaluation of such an alternative standard would represent a minimal departure from NECPA requirements.

Other policy options might be designed to focus not on the intrinsic energy efficiency of individual pieces of equipment, but on the overall energy efficiency of a system of equipment as used in a particular application. For example, for a compressor coupled to a motor drive, alternative policy actions could bear on the proper selection of motor and

compressor for the required load, or on total system performance, perhaps as enhanced by the addition of a variable-speed motor control. Even further from the stated guidelines of NECPA, yet still to be included in the policy analysis approach, are other policy alternatives, such as tax incentives or various means of disseminating energy conservation information.

The approach to evaluating equipment efficiency policies is still under development, and this paper does not attempt to define a comprehensive procedure approved by DOE. The Department of Energy has recently released a report for public comment concerning the study of electric motors and pumps as mandated by NECPA [2]. That study, with Arthur D. Little, Inc., as subcontractor to ANL, incorporated some of the elements of the approach. We have begun to apply the approach to the fourteen other types of industrial equipment listed in NECPA. A description of the approach follows, including a discussion of the data which are needed in order to evaluate policy effectiveness.

INITIAL APPLICATION OF THE APPROACH

The initial approach to the study of the fourteen other types of industrial equipment was developed as a series of equipment characterizations. The purpose of these preliminary characterizations was to lay the groundwork for the more detailed studies by obtaining a quick identification of information pertinent to the studies. Thus in the characterizations, we attempted to define more precisely the types of equipment to be included in each of NECPA's rather broad generic categories. For each of the broad types of equipment, several sub-types were identified. The current state of technological design was assessed, particularly including those design factors having a significant bearing on energy efficiency. The technical potential for efficiency improvement was noted. We attempted to identify existing test procedures for measuring equipment performance, especially those that were standardized either formally or through widespread acceptance and use. Organizations such as technical societies and trade associations that have been or could be involved in setting test or performance standards were identified. Finally, industry attitudes toward energy efficiency as a criterion in the design or purchase of equipment, and responses to possible governmental policies as outlined in NECPA, were sampled.

By design, these characterizations were preliminary and based on limited information and responses. Thus, it would be premature and misleading to present their specific content as conclusions. However, the characterizations did help to shape the more detailed approach to policy evaluation that is the subject of this paper.

POLICY EVALUATION APPROACH

The goal of the policy evaluation approach described here is to evaluate the likely effectiveness of the policies under consideration; that is, to estimate their likely costs and benefits, and to identify any institutional factors promoting or hindering their implementation. For the types of energy conservation policies considered here, be they the labeling rules or minimum efficiency standards of NECPA or the broader range of policies mentioned in the introduction, the evaluation of costs, benefits, and institutional factors demands a solid foundation of technical, marketing, and economic data. Thus, the policy evaluation approach is formulated in three phases, the first two of which are concerned solely with technical and marketing data collection and evaluation. Information from the first two phases is input for the third phase, the policy analysis, as shown in Figure 1.

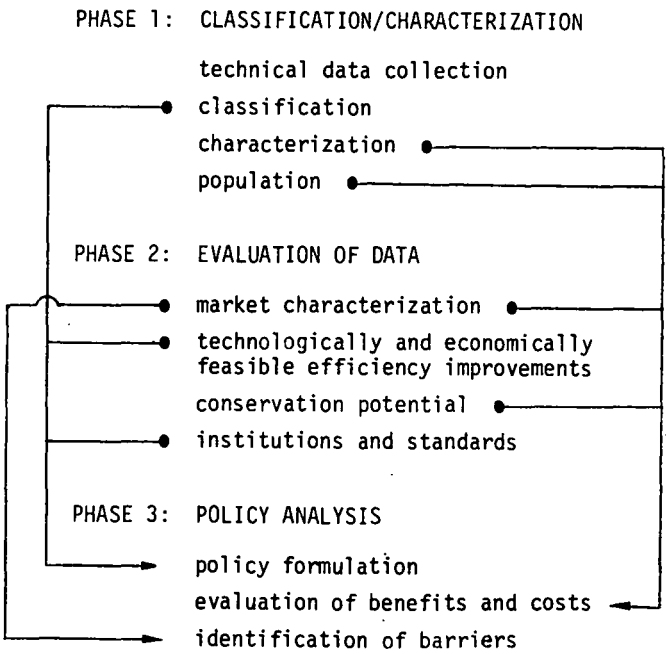


Figure 1. Policy Evaluation Approach

Phase 1: Classification and Characterization of Equipment

In this phase of the evaluation, data are collected concerning the classifications and technical characteristics of the subject equipment. Variations in characteristics of the equipment could lead to many more individual types of equipment than could feasibly be treated in the policy evluation. Thus, it is necessary to aggregate the individual types of equipment into classes, while still maintaining the important distinctions between classes that could bear on applicability or impacts of the policy options to be considered. The technical design and operating characteristics of each class of equipment must be identified, especially those characteristics which have significant impact on energy consumption. In order to evaluate the nationwide impact of policies, it is also necessary in this phase to develop estimates of the population of equipment in industry. These population estimates need to be developed in sufficient detail (for example, broken down by equipment class and by end user) to determine the equipment- and user-specific impacts of the policy options, which may then be aggregated into total national impacts.

Phase 2: Evaluation of Data

Based on the equipment characterizations developed in Phase One, it is possible to evalute the potential energy-conserving improvements in equipment design or application that are technologically feasible. However, to evaluate the economic justifiability of such improvements, it is necessary to develop a detailed market characterization. Consumption patterns, equipment costs, and market mechanisms must be identified for the specific equipment classes and end users. Given the technically and economically feasible improvements, the total conservation potential due to such improvements may be evaluated.

An adjunct to this evaluation is identification of the institutions that are cognizant of equipment design practices potentially affected by the policy options under review. For example, many trade associations and technical societies are already active in setting standards for equipment design and in developing testing procedures.

Phase 3: Policy Analysis

The policy analysis phase of the approach uses the technical and marketing data generated in the previous two phases as the basis for evaluating the impacts of proposed policy options. The policies to be evaluated must be formulated in a manner suitable for the analysis. Then the expected benefits and costs of the policy options can be evaluated, and institutional barriers identified.

Policy Formulation - In order to assess the impacts of a policy, it is necessary to define specific details of the policy. This step should include defining scenarios for policy implementation. For the policy options stated in NECPA, labeling rules and minimum efficiency standards, the policies may need to be defined by class of equipment, to the extent that there are differences among classes affecting feasibility or impacts of the policies. For example, it might be found that for some types of equipment, nameplate labels are of little marketing significance for very large models of the equipment, but of greater significance for smaller, package equipment. The "labeling rules" policy, then, should be formulated in recognition of such a difference between classes. Further specific definition of a labeling rules policy might treat questions of exactly what information goes on the label (for example, a point estimate of efficiency? a range? minimum efficiency? nominal efficiency?) and by what procedure the efficiency is measured. Likewise, for a minimum efficiency standards policy, the policy definition should specify test procedures and sampling patterns, as well as what standard is to be achieved. Scenarios for implementation should include target dates for achieving the policy requirements and reasonable energy cost projections. Among the many such projections which exist are the DOE midterm projections[3], which are incorporated into the recently released final rule governing the methodology for life-cycle cost analyses applied to Federal buildings[4] and are widely used for other analyses as well. Clearly, the policy formulation will require input from the earlier phases of the evaluation in order to define the classes of equipment to which the policies will apply and to assure that the policies are technologically and economically feasible. Finally, the policy definition needs to specify what role the government will have in carrying out the policy. In such definition the capabilities and program status of trade associations and technical societies should be considered.

Policies other than those specified in NECPA may also be incorporated into the evaluation

approach. For example, there may be adaptations of the ideas of labeling rules or minimum efficiency standards which are more feasible for certain types and classes of equipment. To illustrate, in the case of very large custom-built equipment, the units are typically built to a specified efficiency. For such equipment, a policy more practical than labeling or standards might simply be testing to verify that the unit meets the specification. Or for some types of equipment, rather than apply a minimum efficiency standard, an alternative performance standard might be considered more feasible (for example, a maximum exit gas temperature for large thermal equipment). The formulation of such alternatives clearly requires the input of technical expertise into the policy evaluation.

Such policies should not be considered in isolation, but in comparison with other means of achieving the goal of industrial energy conservation. Thus, the policy evaluation approach properly incorporates other policy alternatives, such as tax incentives, or programs to inform manufacturers and end users about current conservation options and their associated costs and savings. Such alternatives may themselves be candidates for detailed evaluation independent of the NECPA studies. In any case, whatever policies are to be studied in detail need to be defined in sufficient detail to permit meaningful projections of benefits and costs.

Evaluation of Benefits - The chief benefit to be expected from any policy option is the saving of energy over and above what would be saved in the absence of the policy. Therefore, a projection of industrial energy consumption assuming the status quo with respect to governmental policy must be made. This base projection should still incorporate the energy savings to be anticipated from more energy-efficient equipment solely as a result of economics, in light of the energy cost projections mentioned earlier. The market penetration of such equipment and the resulting energy savings and dollar savings may then be projected assuming the various policy options are implemented. Measured against the base projections, these projections then indicate the benefits due to the policy options. It may also be possible to specify the energy savings by type of fuel, or to assess the effects of fuel substitution.

As does the definition of policy options, the evaluation of energy savings requires information from earlier phases of the approach. Specifically entering into the evaluation of savings could be a market characterization, from which it may be determined whether and how efficiency information might be gotten to the ultimate decision-makers; estimates of equipment population, lifetimes, and replacement rates; and an energy consumption characterization of the equipment affected by a policy option.

Evaluation of Costs - The costs associated with policy options include direct costs to the government, manufacturers, and end users, and indirect costs (externalities) which may accrue to industry or to society as a whole. The government would incur some costs for administering a program. Clearly, these costs depend to a great extent on what role the government has in the program. Manufacturers may incur retooling costs (if redesign of their equipment is necessary), increased production costs, or cost for performance testing. These costs would ultimately be felt by the end user.

These direct costs are usually fairly easily quantified. Externality costs, though more difficult to quantify, should always be identified, and quantified wherever possible. Such costs might include perturbations of manufacturers' market shares (particularly those of small manufacturers), macroeconomic effects, or effects on international trade. To the extent that such costs may be expressed in common units (typically dollars), they may be combined with direct costs to the enhancement of the policy evaluation.

When the benefits and costs of the policy options have been quantified as far as possible, it is desirable to express the effectiveness of a policy in some consistent terms. The nondimensional ratio of benefits to costs (or marginal benefits to marginal costs) is a familiar measure. Other typical units of measure that may be useful include dollars per million Btu or dollars per barrel of oil equivalent.

Identification of Barriers - For even the most economically attractive conservation measures, there may be institutional or political factors hindering their adoption. For example, some market mechanisms may be governed by noneconomic constraints, such as environmental regulations. Where such constraints exist, the policy evaluation approach seeks to

identify them, their impact on the market, and potential means of dealing with them in the context of the policy options under review. To do this effectively requires a sound characterization of the operative market mechanisms as discussed under Phase Two.

CONCLUSIONS

It should be evident that a sound evaluation of energy conservation policies cannot be conducted in a vacuum. The evaluation of impacts of possible policy options requires a solid foundation of information about the equipment and market operations that would be affected by the policies. The necessary data can best be supplied by industry itself; groups such as trade associations may be utilized to protect the confidentiality of individual firms' data. Additional input from industry is needed to help define the appropriate roles of government and industry in the development and implementation of improved equipment design, testing, marketing, and application practices to realize the goal of energy conservation.

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ENERGY-SAVING PUMPING SYSTEMS IN CHEMICAL PLANT DESIGN

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ABSTRACT

The current cost of electrical power is translated into an annualized value to be used for economic considerations in the selection of pumping equipment. Motor sizing guidelines are suggested to permit electric motors to operate nearer peak efficiencies. The need to provide adequate net positive suction head for centrifugal circulating pumps is illustrated. Situations are cited where variable speed drivers can be employed advantageously. Margins of safety and control valve pressure drops should be scrutinized.

ELECTRICAL ENERGY COST

With the cost of electrical energy now around 4¢ per kWh it behooves the process design engineer to be aware of this and apply energy saving measures in his designs. Many chemical plants operate continuously (8760 h/yr). Thus the 4¢ kWh translates into $307.53/hp/yr ($0.04/kWh x 0.746 kW/hp x 8760 h/yr ÷ 0.85 motor efficiency). The direct power cost per brake horsepower for a 10 year life project would be $3075.

SIZING MOTORS

Some users specify that their pump motors be sized to be non-overloading over the entire centrifugal pump performance curve. This can result in larger-than-necessary motors operating well below peak efficiency and with a poor power factor. It can also result in larger, more costly switch gear, wiring and oversized transformers. Many pumps cannot be operated over their entire curve because they are restricted to a feed rate by a control valve or are flow-limited by the piping system-pressure drop curve. Both API Standard 610 for refinery pumps and ANSI B73.2 Standards for vertical in-line chemical pumps have recommended motor sizing procedures based upon a percentage above the pump rated brake horsepower. This is a much better energy-saving approach.

CALANDRIA CIRCULATING PUMPS

One of the most common faults in chemical plant design is the specification of a distillation column without proper regard to the calandria circulating pump's net positive suction head (NPSH) requirements. The column designer will always want to keep the skirt height to an absolute minimum to save on steel and piping costs. Also, he seldom has adequate appreciation of the centrifugal pump's requirements. The process or project design engineer has the prime responsibility to provide for adequate NPSH. He can accomplish this by consulting:

(1) with a pump application engineer, either within his organization or with a pump manufacturer;

(2) centrifugal pump performance curves which are usually available in the engineering department's catalog files; or

(3) the Hydraulic Institute Standards which give NPSH guidelines.

The consequence of not providing sufficient NPSH is that the pump selected will be oversized and will be operating to the left of the best efficiency point (BEP). Pump A in Figure 1 operates at a BEP of 85% and requires 6 feet of NPSH while pump B only requires 3.3 feet but it is oversized for the service and only operates at 65% efficiency. Pump A requires 15.6 hp at design while Pump B requires 20.4 hp. Thus pump A costs less and offers a 4.8 hp saving (~31%).

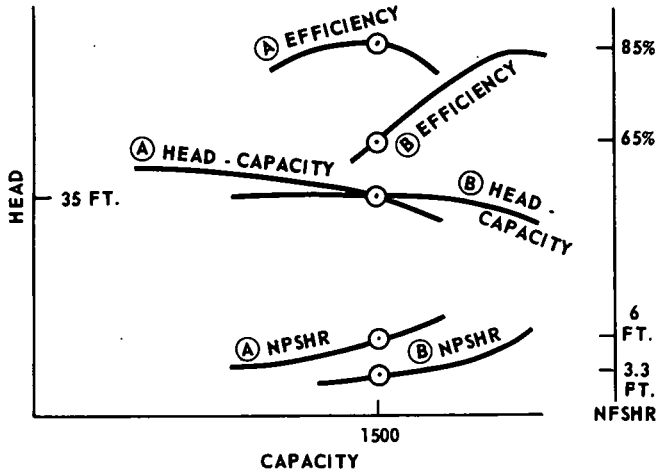


FIGURE 1

VARIABLE SPEED DRIVERS

Variable speed drivers should be evaluated for pumping systems where the capacity varies widely and where the system-pressure drop curve is rather steep. Wastewater collection sumps are typical. (See Figure 2)

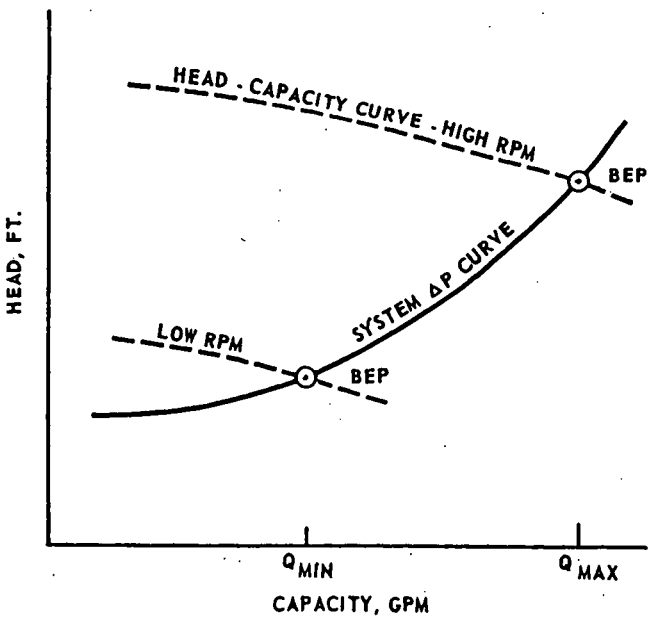


FIGURE 2

A centrifugal pump's capacity varies directly with rpm; its head varies with the speed ratio squared and its horsepower varies with the speed ratio cubed. Since piping frictional losses tend to vary as the flow ratio squared, a centrifugal pump with a variable speed driver can follow the variable head-capacity demands very nicely and can quite often always operate in its best efficiency region. In Figure 2 the horsepower losses could be extreme if a fixed speed pump was used in conjunction with a flow control valve to operate at $Q_{Min.}$ for extended periods.

MARGINS OF SAFETY AND CONTROL VALVE PRESSURE DROP

Excessive margins of safety (rated capacity above normal) can waste energy in three ways. First, it causes the selected pump to be oversized to meet the rated flow. Usually the BEP is at or near the rated flow so when the pump is operating at the normal flow it is operating less efficiently to the left of BEP. Secondly, it causes greater losses through the control valve used to regulate the pump to normal flow. (See Figure 3) Lastly, the larger motor required to operate the pump at rated capacity is operating at partial load and at lower efficiency.

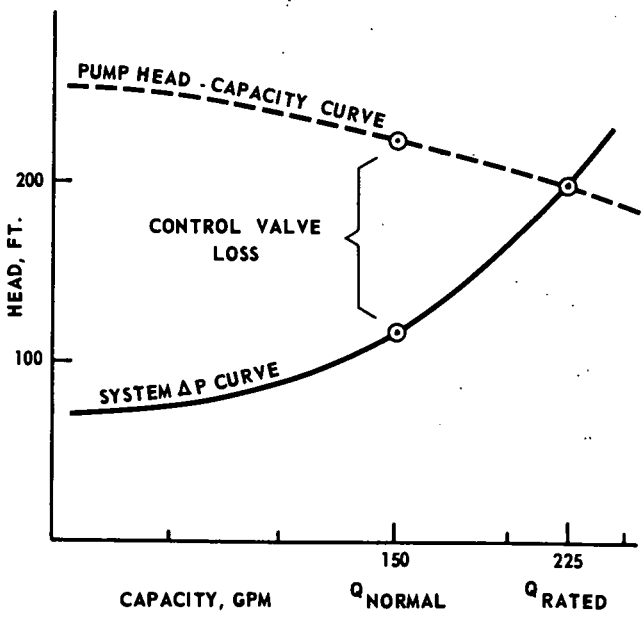


FIGURE 3

In Figure 3, with a 50% margin of safety and assuming a pump efficiency of 70%, the horsepower required at the rated point is 16.23. The hp required at Q_n to just meet the system head of 117 feet is 6.33. We obviously need some pressure drop for control but let's not go overboard. A 10 hp driver could do this job nicely.

Quite often control valve pressure drop requirements as specified by control systems engineers are established by a general "rule of thumb" rather than by examining each application. One example that came to light was a rule that required the valve pressure drop to be equal to all other dynamic losses in the system at maximum flow. With large margins of safety, a valve selected on this basis would operate near closed position at normal flow with extreme power losses as well as poor control characteristics. In existing production units it might be rewarding to examine your flow control valves for large pressure drops. A shaved impeller with a smaller motor or even a new smaller pump may be justified.

THE ROLE OF THE FLEXICOKING PROCESS IN HEAVY-OIL PROCESSING

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ABSTRACT

The recently commercialized FLEXICOKING Process has a significant role to play in developing known heavy oil reserves. The process upgrades virtually any pumpable feed including residual, pitch, or total crude. Combined with HYDROFINING, it produces a clean product slate composed of low Btu gas, high Btu gas, LPG, naphtha, distillate and gas oil. The low Btu gas falls within the definition of an "Alternate Fuel" under current legislation (PL 95-620).

Originally developed for refinery bottoms conversion, the FLEXICOKING process can also be used as the primary technology for Stand Alone Energy Centers upgrading low quality, high metals, heavy crudes. These efficient energy centers can be located either at a heavy oil production field or integrated with an energy-intensive industrial complex.

This afternoon I will introduce you to our new FLEXICOKING Process. This technology has been recently commercially proven, and we believe it has a significant role to play as this country develops its heavy oil reserves. I'll describe FLEXICOKING and give you some background on the development of the process. We will see where it fits into today's energy scenario, and I will bring you up to date on some projects in progress at the present time.

BACKGROUND

FLEXICOKING is a logical extension of our FLUID COKING process, which in turn built on the fluid solids experience accumulated in cat cracking since the second world war. The first commercial application is at the Toa Sekiyu Refinery in Kawasaki Japan. This is a 21,000 B/D unit. Initial startup was in September of 1976, and it has passed all of the design performance tests and meets strict environmental standards for the Tokyo area. This slide shows the Toa unit in operation. The large vessel at the left of the slide is the gasifier.

THE PROCESS

Now let's step through the simplified flow diagram (Slide 2). These three fluid solids vessels are the heart of the process. Heavy feed (residual fuel or pitch) is fed to the reactor. A thermal cracking reaction takes place in the bed of fluidized coke. Heat balance is accomplished in a manner very similar to a fluid catalytic cracker. Heat is transferred by circulating coke from the exothermic reaction taking place in the gasifier to the endothermic reaction taking place in the reactor section.

Steam and air are introduced through a proprietary grid into the gasifier bed. The low Btu gas formed goes overhead in the gasifier,

into the bottom of the heater and out through cleanup with three stages of cyclones and a venturi scrubber. Sulfur is removed from the gas prior to burning. This low Btu gas typically runs from 100 to 120 Btu/cubic ft. and burns very nicely as a clean industrial fuel gas.

Reactor products are quenched in the scrubber and go on to fractionation and light ends recovery which are not shown on the slide. As you can see, the process is non-catalytic. Metals contained in the feed are purged in a small drag coke stream from either the dry cyclone or the wet venturi. On extremely high metals feeds, additional purge may be required from the circulating bed coke.

WHERE DOES IT FIT?

Let's move now to where the FLEXICOKING process fits.

- Low Quality Feeds - The process can handle any pumpable resid or pitch. It can handle low quality crudes containing high sulfur, high metals, high con carbon, and high asphalt content.

- It Provides Flexibility - It gives an operator the luxury of missing on his predictions of crude slate and product mix. The process fits into both low sulfur fuel oil and high conversion refineries. We think this flexibility will become more and more important.

- High Yield of Liquid Products

- Alternate Fuel Mandate - The low Btu gas is produced by gasifying petroleum coke. This meets the definition of an alternate fuel under existing coal conversion legislation (Public Law 95-620).

- And finally where there is no economic outlet for high sulfur or high metals coke.

The process was originally developed for refinery bottoms conversion. The first three commercial units are actually going into this type of service. We're finding, however, that this technology may have a much broader application as stand alone energy centers. One form of these energy centers combines FLEXICOKING and hydroprocessing. This combination upgrades pitch or low quality feedstock to produce premium fuel, steam, power, and in some cases petrochemical feedstock. It is potentially a cost effective fit with any energy intensive industrial complex.

Another approach is to locate the energy center at a heavy oil production field. We have two max train units in design for Imperial's Cold Lake heavy oil project in Alberta, Canada. The clean low Btu gas can be used to generate steam for the heavy oil production operation and as fuel for hydrogen manufacture.

After hydroprocessing, the liquid products can be reblended as a high quality crude to be further processed in existing sweet crude refineries. They can also be sold directly into the market place as premium products.

You will note that the fixed bed catalytic hydroprocessing is working on distillate type streams, not resid. These streams are essentiall

free of metals which act as catalyst poisons. This approach results in lower catalyst volumes, less severe conditions, and lower cost construction.

Let's look at some of these applications. Slide 3 shows the typical product streams from a FLEXICOKING unit, starting with low Btu gas at the top of the slide, high Btu gas, LPG, naphtha, distillate and gas oil. Metals are purged in a small drag coke stream. Now we superimpose yields based on feeding Arabian Heavy vacuum resid to the unit. The low high Btu gas are expressed here as fuel oil equivalent. The other products are on a liquid volume basis.

Virtually all of the energy input to the process comes from the exothermic reaction taking place in the gasification of the coke. Thus, oxidation of coke supplies the energy for conversion to light products, and no premium fuel is needed. This is a very high con carbon feed (just under 28%). With this feed, the low Btu gas expressed on a fuel oil equivalent basis represents just under 23% on feed. This is 5 to 6% on total crude charge.

STAND ALONE ENERGY CENTER

Let's move on now to the new application I mentioned earlier, the Stand Alone Energy Center. Slide 4 shows total Boscan crude going to the combo version of the FLEXICOKER. Feed is introduced into the scrubber. The material boiling below 900°F is lifted by the hot reactor gases, eliminating the need for upstream fractionation. The yields are expressed the same as in the previous slide, and there is some shift as the result of the different feed and the yield distribution of the virgin material boiling below 900°F. In this case, the low Btu gas, which is the only product which cannot be transported long distances, yields approximately 10% on total crude feed. This is somewhat higher than the previous example. Also, the overall yields are slightly lower because all of the feed is not being cracked to lighter products, as was the case on the Arab Heavy vac resid feed. As we said earlier, this type of an energy center can either be located in the production field or integrated into any energy intensive industrial complex.

PRODUCT DISPOSITION

With the types of feeds we've shown here, the product streams from the FLEXICOKER obviously carry high sulfur contents and require further processing. Let's see what this might look like. Slide 5 shows the same product streams we saw earlier, but with downstream processes superimposed. In this case the low Btu gas is used for cogeneration of steam and power and for fuel in hydrogen plant furnaces. I'll come back to this later.

A portion of the high Btu gas is used for hydrogen plant feed after hydrogenation and sulfur removal; and the balance is used for fuel. In this case, the C_3/C_4 disposition is to LPG. Naphtha goes to HYDROFINING, then either to cat reforming or chemical feedstock. Distillate and gas oil streams may be run concurrently in a gas oil hydrotreating (GOFINING) process. The hydrotreated distillate can be separated into Number 2 fuel and gas oil. In situations where there is a market for ground based combustion

gas turbine fuel, this broad cut stream is very suitable for turbine fuel with relaxation of some of the historical fuel specifications.

In other applications, the distillate streams may be severely hydroprocessed to produce premium jet fuel and diesel products.

COKE GAS

I'd like to come back now to the low Btu gas produced by this process. As I mentioned earlier, since it has a heating value below 600 Btu/Cu. Ft., and because it is derived from petroleum coke, it meets the definition of an "Alternate Fuel" under current coal conversion legislation.

Further, the burning characteristics of this gas have turned out to be a pleasant surprise. It's stable burning characteristics were originally demonstrated in a small vertical cylindrical furnace at the 750 Bbl/Day prototype unit at the Baytown refinery. The burning characteristics were subsequently confirmed at the commercial plant in Japan in a pipestill furnace, steam boiler and in a steel mill application. Test work in-house and by furnace and burner vendors, has demonstrated that the coke gas is also suitable as fuel for hydrogen plant furnaces. This is a fortunate fit because as we have seen earlier, hydrotreating is required on the naphtha and heavier product streams from the unit.

Conventional process furnaces can be retrofitted to handle this low Btu gas. Because of the dilution effection of the inerts in the fuel gas, the gas volume which must be handled by the convection section and stack ducting is increased approximately 40%. As a result, draft capability has to be augmented with induced draft fans or additional stack height. The furnace, however, retains a radiant and convection section configuration. It looks like a furnace, not a dutch oven.

COMMERCIAL EXPERIENCE

Let's see what the lineup of commercial plants looks like. (Slide 6) By way of background we have eleven operating FLUID COKING units, the forerunner of the FLEXICOKING process. These affiliate and licensee plants were built between 1954 and the present time, and range in size from 5,000 B/D to 73,000 B/D capacity.

The FLEXICOKING process was demonstrated in a 750 Bbl/Day prototype unit constructed at our Baytown refinery in 1974. It was followed by a 21,000 B/D unit in Japan which started up two years later. The first large unit (52,000 B/D) is currently under construction at Petroven's Amuay refinery in Venezuela.

The first stateside application is a 22,000 B/D unit currently in detailed design for a West Coast location. The second U. S. FLEXICOKING unit is currently in process design in our shop. This is a 31,000 B/D unit and will be the first to be incorporated as part of a grass-roots refinery design.

Imperial Oil in Canada has just completed process design of two 50,000 B/D units for their Cold Lake heavy oil project in Alberta, Canada. I believe that you can see from this that the

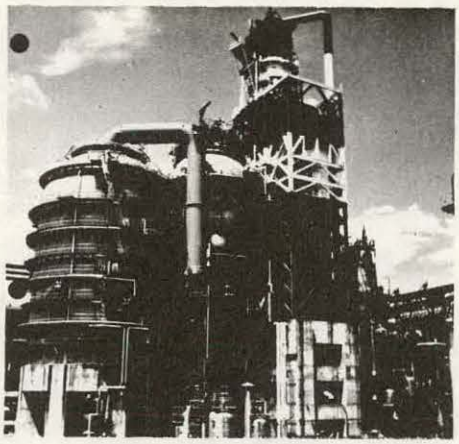
FLEXICOKING process is establishing itself in the industry. We believe this will continue as increased volumes of heavy, high sulfur, high metal crudes are produced.

SUMMARY

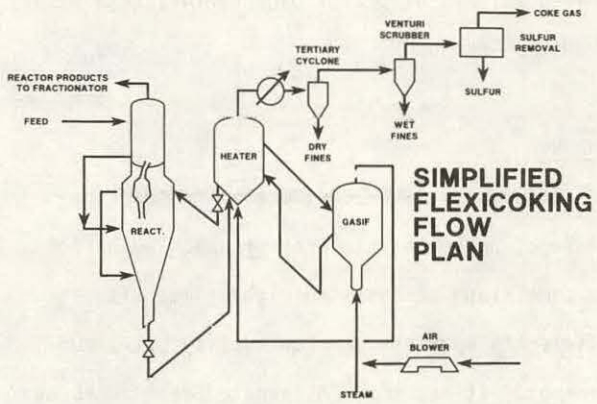
In summary, FLEXICOKING is a rugged, low pressure, non-catalytic process which we believe has come along at just the right time. It efficiently upgrades our low quality petroleum reserves. It has some "Alternate Fuel" features. Virtually all of the product slate is usable as premium fuel or feedstock, and it is commercially proven.

This completes my comments. I'd be glad to answer any questions.

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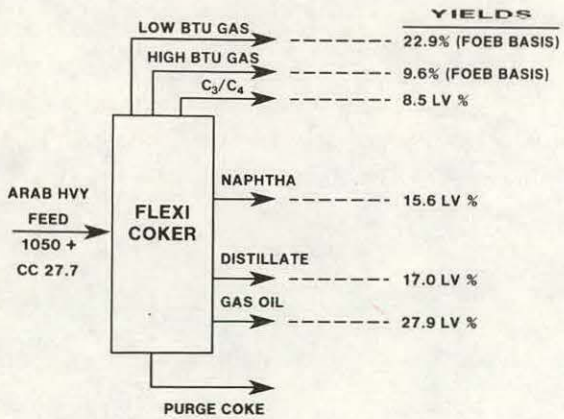


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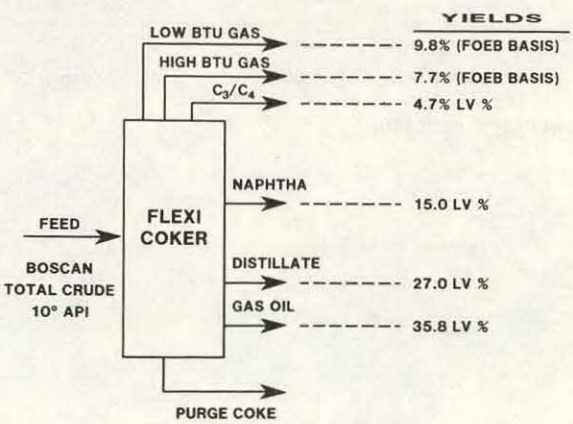


SIMPLIFIED FLEXICOKING FLOW PLAN

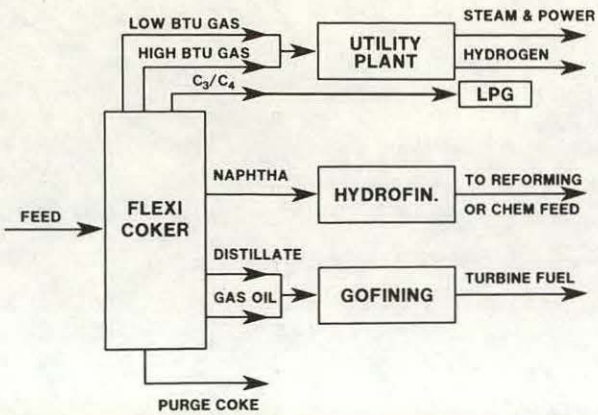
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3.



4.



5.

FLEXICOKING PROCESS IS COMMERCIAL

		STARTUP
EXXON BAYTOWN PROTOTYPE	750 B/D	1974
TOA, KAWASAKI	21,000 B/D	1976
PETROVEN, AMUAY	52,000 B/D	1982
WEST COAST, U.S.	22,000 B/D	1982
GRASSROOTS REFINERY (U.S.)	31,000 B/D	1984
IMPERIAL, COLD LAKE	TWO 50,000 B/D	MID 80'S

6.

U.S. INDUSTRIAL ENERGY CONSUMPTION AND CONSERVATION: PAST AND FUTURE PERSPECTIVES*

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ABSTRACT

This paper examines U.S. industrial energy consumption and conservation potentials by defining the concept of energy service which, in turn, leads to more precise consideration of various aspects of energy conservation. It is seen that there are a number of components which contribute to energy conservation in the industrial sector. These consist of product and process change, energy efficiency improvement and energy management. The total energy demand is projected on the basis of production indices, reduced (historical) energy service requirements per unit of production and estimates of efficiency improvements.

The focus of this analysis is definition of the particular issues whose exploration would best improve the quality of projections of energy use. At the same time, we obtain a reasonable estimate of energy consumption for the industrial sector as a whole.

INTRODUCTION

The United States is faced with the gradual erosion of its best primary energy resources: oil and gas which are both cheap to extract and cheap to use. The national policy response has been focussed on the development of new energy supply technologies and on regulations restricting industrial use of oil and gas.

These policies have been much less than successful. The attempt to create new widely available sources of energy, such as fluid and gaseous fuels from coal and oil shale and electricity from nuclear fission, have encountered serious difficulties. Proposed "synfuels" plants have been delayed and scaled down. The mandated shift of industry to coal is not occuring. This has been a time when, on the basis of simple economic principles, one would have thought that alternatives to oil would thrive. Instead, the national dependence on imported oil is greater than it was in 1973, and the nation is in some jeopardy because of undependable supplies, as evidenced by the revolution in Iran and the nuclear accident at Three Mile Island.

There is an alternative approach: to address the entire energy system, the means of energy use as well as its supply. This paper deals with the energy use patterns in the industrial sector.

Two developments persuade us of the critical significance of change in the way energy is used in industry. The first is the historical record. There has been a long-term decline in energy consumption per unit of production. This trend has accelerated since 1973. Much of this improvement is associated with change in the mix of products. Some of the recent decline is associated with improved energy efficiency in the making of products. The rapid rate of decline, perhaps 2% per year, would, if sustained, solve industry's energy problems.

The accelerated decline in energy use per unit of aggregate production since the oil embargo is not really surprising, in view of the prices industry has been paying for energy. Industry has experienced the greatest energy price increase of any major group.

The second development which has persuaded us of the importance of changes in the use of energy is a group of studies (1) which suggest that substantial technical and economic opportunities remain to cut energy related costs and enable industry to regain control over its energy services.

These technical opportunities include, of course, the institution of energy conservation; that is, the concerted attention to increased production energy efficiency. In order to put these opportunities in proper perspective, it is important to present certain basic concepts about industrial energy demand which, unless re-emphasized, are often lost in discussions of our energy crisis.

* Some of the concepts in this paper are taken from the book by Marc H. Ross and Robert H. Williams, Our Energy/Regaining Control, to be published by McGraw Hill Book Company.

CONCEPTS

Energy Services

In the analysis of industrial energy use, the concept of function, or "energy service," is critical. Examples of energy services are drying, melting, heat treating, electrolytic separation, and forming of metal parts. Energy service is an important concept because:

1) It is these services which are needed rather than energy as such; as a result projections of energy needs should rest on analyses of the needs for energy services.

2) The energy carrier, which is the form in which energy is delivered to the point of use, is sensitive to the energy services which it can economically provide.

3) The opportunities for cost reduction for energy conservation and the appropriateness of policies to support them are also sensitive to energy service.

The purpose of the energy service concept is to focus attention on the combined system of energy carriers and the means of their use, in contrast to considering the energy itself. Consider, for example, the service of forming sheet steel into certain pieces in contrast to the provision of a certain amount of electricity to drive the machines. This distinction is logically important because the manufacturer has a variety of opportunities to change the way in which the electricity is used, reducing the electricity required and reducing overall costs in the face of the increased price of electricity (compared to its price when his process was installed). With the energy price increases that are occurring, very substantial reductions in energy needs (and shifts among energy carriers) may be desirable and achievable for each unit of energy service.

Describing energy consumption in terms of energy services can be difficult conceptually. We tend not to think in terms of energy services but in terms of energy carriers. For example, in analyzing industrial process heating, which employs steam, we think in terms of the steam whereas it might be more appropriate to consider the function of the steam, e.g., drying or cooking of certain materials.

Before going into a specific definition of energy service, let us consider a fundamental conceptual difficulty due to the fact that a given task can be accomplished at many different levels, ranging from the very narrow to the very broad view of the process.

Levels of Technological Change

Consider a manufacturing service. The fundam l task is to provide a final product with certain essential characteristics. In this general view of energy service one option for the manufacturer is to change the design of the product, altering it without changing its essential character; another option is to fundamentally change the manufacturing process. In addition, the energy conversion equipment may be changed and the manufacturer's energy management practices may be improved.

The key element in product design from the standpoint of manufacturing energy is use of basic materials since the basic materials industries consume 5/6 of all energy used in manufacturing. The product can be made lighter by design and by change in certain other attributes, yet retain its basic functional characteristics. Substitutions among materials can also be made. More or less secondary (recycled) material can be used, or the product's durability can be changed.

We often think of a basic material in terms of a specific process of manufacture - so well-established are certain processes. But history shows that processes do change when a new process provides clear advantages. In recent decades, the float-glass process has taken over flat glass production, and petroleum feedstocks have taken over in the manufacture of many established chemical products.

Energy conservation technologies have been a focus for DOE programs for manufacturing. In effect, this approach rests on a narrow but significant definition of energy service, e.g., the provision of heat of a certain temperature and other qualities, service which can be provided by various fuels and by more or less efficient heaters/furnaces.

Energy management refers to minor retrofits such as simple control systems, changes in operating procedures such as turning off equipment not in use and improvement in maintenance practices. This is a rich area for improvements by a determined and inventive staff which is adequately supported by corporate management.

If the energy services in manufacturing are broadly defined to be the provision of products with certain essential characteristics, it is seen that a whole complex of changes may be made to make the energy services less costly and to change fuel require-

ments. This is a valuable concept because firms and policy makers should not restrict their attention to refinement of existing equipment and processes where more fundamental changes in product or process would offer the greatest cost savings.

These options, product and process changes and changing energy technology efficiencies and fuel switching, are now cast in a logical framework by defining the concept of energy service demand.

Service Demand

From our earlier notion of energy service, the concept of service demand is now developed in terms of an illustrative industrial unit operation, a reforming process in petroleum refining. Figure 1 depicts the two essential steps where Naptha is heated in a tube-still heater before entering the reforming chamber. In this simplified representation, all the process energy is imparted to the material in the heater section and the main chemical reaction takes place in the reformer chamber.

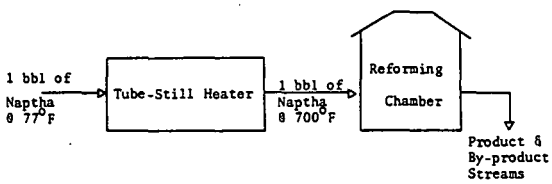


Figure 1

The first law energy balances for heating a unit volume of the material are portrayed in Figure 2. There are two kinds of energy services involved; the heat flows with units in Btu's, and the machine-drive inputs in kilowatt-hours. The following discussion is based on heat flows, although changing tubestill heater technology may also alter machine-drive.

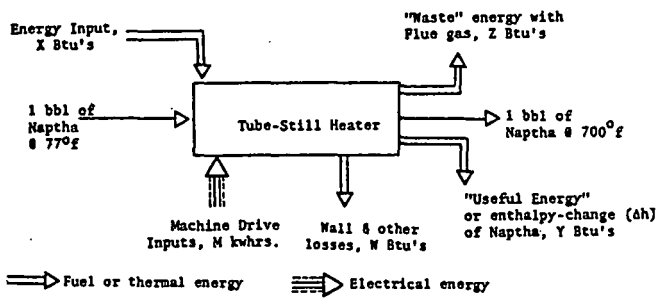


Figure 2

The heat flow inputs and outputs, portrayed in Figure 2, are governed by heat balances according to the first law of thermodynamics:

Total Energy Input = Total Energy Output + Energy Accumulated in the System

The total energy inputs, X Btu's, are measured in terms of the energy of the fuel put in. The outputs take the form of "useful energy," or the heat energy absorbed by the materials being processed, Y Btu's; and losses in the form of waste streams exiting with flue gases, Z Btu's, and leakage through walls, W Btu's. So, for the steady-state operation:

$$X = Y + Z + W$$

The temperature, pressure, and other conditions which determine Y, the enthalpy change, are governed by the process of reforming and are considered to be fundamentally tied to the process characteristics. This term, Y Btu's of "useful energy" or enthalpy change required per unit of material processed, will be called the Service Demand. The other terms, like energy inputs and wall losses, are subject to equipment and operational improvements. For the simple system in Figure 2, where there is no provision for waste-heat recovery, etc., the first law of efficiency is simply:

$$\eta = \frac{\text{useful energy}}{\text{energy input}} \quad \frac{Y}{X}$$

A number of alternative technology configurations are available for imparting the same "useful energy" or "service demand" but with different efficiencies; capital, O&M and fuel costs, and fuel-forms. The various alternatives will be delineated so as to keep intact the basic characteristics of the system in terms of parameters like final temperatures, pressure, and service-demand for Naptha. This is obviously necessary for a uniform comparison and evaluation of various technology options.

Technical options can be classified according to the basic source of change. These are based primarily on the input-output categories of Figure 2.

Alternative Fuel Inputs

Assuming that the basic tubestill heater is retained, there are alternative basic fuels. Traditionally, natural and refinery off-gases or residual or distillate oils are used as the basic fuel. But in certain tubestill heater applications, pulverized coal is a feasible alternative. Hardware, economic and fuel use parameters will vary not only from fuel to fuel, but also between new and retrofit applications. Thus, for example, for a tubestill heater of a given rating, originally designed for firing natural gas, burning coal would be virtually impossible without a severe derating of the equipment.

Alternative Hardware Options in the Energy Conversion Equipment

The second set of alternatives emerges from variations within the hardware of the energy conversion equipment. In the case of our example, the tubestill heater, there are alternative ways of arranging tube parameters (including the material the tubes are made of) to yield improved efficiency. This will typically be at higher capital cost.

Wall and Other Leakage Losses.

Efficiency improvement options include investments in the use of improved insulation, and improved practices such as more frequent maintenance and training of staff to improve quality of combustion. In Figure 2, the losses due to leakage, etc., were lumped together as W Btu's. If, for example, insulation reduces these losses to W', the resulting efficiency of the process will become:

$$\eta'' = \frac{Y}{X-(W-W')}$$

Waste Heat Recovery

There are substantial possibilities from this category because most of the losses in many applications go to "waste streams," or flue gases. A substantial part of these are, at least in principle, recoverable.

Waste heat recovery technologies generally involve recovering part of the heat contained in the flue gases and using it to preheat either the material being processed and/or the air for combustion.

In general, for each technology option arising from alternative fuel inputs above, there is likely to be a different waste heat recovery system. Thus, the system using natural gas is likely to be the most compact, whereas oil and coal generally result in complexity because of increased fouling and the residue problems of sulfur, ash, etc.

Sophisticated Control Systems

The operation of the heater can be optimized in terms of variable load conditions by means of sensors and electronic processors. Optimization in terms of down-stream functions can also be approached by analyses correlating heater operating parameters with down-stream performances.

Change In Service Demand

So far, the schemes considered involve altering the basic energy conversion hardware, or limiting wastes and optimizing operations. But, all of these were accomplished without affecting the basic process, and consequently, the service demand. There is one major category of change which involves alterations in the process, and hence the service demand. Examples of minor alterations consist of variation in tray arrangement of a distillation column or a new catalyst in a catalytic reforming process. Both of these will change the energy services required to accomplish the end goal. Major changes may involve different feedstocks or a different mix of unit operations. For example, heavier feedstocks may be adapted using advanced cracking reactors, which will have implications for a series of operations through which the material is processed. Such process change has major cost and energy implications. Many difficult decisions must be made between renovating existing facilities and processes or creating new facilities incorporating state-of-the-art processes.

In addition to changes in the efficiency with which an energy service is provided and process changes, the mix of products which make up the market basket of industrial products must be considered. All these kinds of change will be considered across industry in the next section.

INDUSTRIAL ENERGY CONSERVATION OPPORTUNITIES

The kinds of technical change which may strongly affect the costs and demand levels of industrial-energy services can be roughly categorized according to the kind of decision involved in their adoption. We have chosen the categories:

(a) Product-related changes, especially changes in product mix and design which affect the use of basic materials.
(b) Fundamental process changes, changes which require large investments and impact a variety of factors of production.
(c) Changes in equipment or energy technologies which involve significant investment and are primarily connected to energy use and costs.
(d) Changes in management, operations and maintenance, and retrofit with low-cost equipment, which affect energy use.

Product Change

From an energy standpoint, the predominant issue in product mix and design is the requirement for materials. Product mix and design are largely determined in the market; the cost of energy in manufacturing is usually a minor issue. Nevertheless, there leeway for cutting energy-related as well as materials costs by reducing materials requirements. In addition,

changes are occurring in materials use because of external factors such as environmental, safety and energy performance standards.

The remarkable changes taking place in the design of automobiles illustrate several types of changes. The changes in auto weight, primarily to improve fuel economy, are taking the average car of 4000 lbs. of the mid-seventies to about 3000 lbs. in 1985, and perhaps, to under 2000 lbs. by the millenium. At present, about 1/3 of the weight reduction is being accomplished by materials reductions as such, and 2/3 by vehicle size reductions. Use of stronger but thinner sheet steel is an important part of materials reduction. Increased use of plastic including strong reinforced plastics (composites) and aluminum is also important.

Use of secondary materials can again be illustrated by the automobile. Perhaps 90% of discarded automobiles are now being recycled, a much higher fraction than for most steel products. Auto design is important to recyclability both to the extent special, e.g., low impurity steel is required for the manufacture of new cars, and to the extent that impurities will tend to become incorporated in the scrapped vehicle. Copper and nickel make steel brittle, so avoidance of these materials in cars, design to make their removal from the obsolete vehicle easy, and the use of secondary processing which effectively extracts these materials, are strategies to improve the quality of scrap steel.

Design for durability, repair and remanufacture is an issue attracting increasing attention. Improvement of these qualities is an important option for buyers of products, especially if the fundamental technology is stable. The remarkable achievements which are possible are illustrated by products which are designed for lease: certain computers, copiers and telephone equipment. Returning to our example of the automobile, during this time when auto technology is changing very rapidly this option should, and probably will, have relatively low priority. In the future, this option will offer an intriguing challenge to auto makers and marketers.

Process Change

Process change is an industry-specific issue. We briefly describe change in terms of examples in paper and steel industries.

Steel. In iron and steel process change can be discussed in terms of the four stages of the overall process: the making of iron from largely virgin inputs, steelmaking, semi-finishing and finishing. In the reduction of iron ores the blast furnace remains supreme even while coke is a problem because of air pollution and difficulties in the coal industry. Larger, higher-pressure blast furnaces are being built, almost exclusively overseas, and offer substantial cost and energy savings. In the U.S. a program of improvements to existing blast furnaces, increasing capacity and reducing costs and overall energy requirements, is enabling the retirement of a remarkable number of less productive furnaces.

Steel making is evolving, as basic oxygen plants and electric furnaces are well on their way to replacing open hearth furnaces, with significant benefits. The semi-finishing step is changing with the introduction of continuous casting, and, especially overseas, of direct rolling. These operations replace ingot casting, reheat and rolling, and a second reheat and rolling, with substantial energy and materials savings. The immediate creation of semi-finished products creates serious inspection and scheduling problems, but offers the potential for more effective quality control.

The finishing step, consisting for sheet steel, of surface preparation and of cold rolling and annealing to produce desired hardness, is labor-intensive and not very energy intensive. Automatic control and continuous product flow are important developments. A radical type of change which could eventually take a major market share with substantial cost savings is direct forming of products as, for example, with powder metallurgy.

Paper. In pulp and paper we focus on substantial changes occurring in pulp making, several of them associated with initiatives being taken in Scandanavia. More complete use is being made, and will be made, of the tree, including transport of forest wastes to the mill and possibly extraction and use of the tree root. Much of the added material is being used as fuel in boilers, with substantial reduction in use of fossil fuels. There will be moves to greater use of continuous pulping with sophisticated process controls. Some change in the mix of chemical and mechanical pulping processes will occur, with uncertain energy impact.

Dramatic changes in the paper industry are occuring in the use of water. Both closed (or almost closed) systems and processes requiring less water are actively being implemented. As an example of the lat-

ter, bleaching can be accomplished by successive stages of diffusion of chemicals through the pulp rather than successive stages of soaking and washing. Reduced intake and discharge of water should have substantial impacts on both energy requirements and water pollution.

Energy Technology

Process Heat. Many of the broad range of opportunities were mentioned in the example above. One process change of special interest is heating by electromagnetic means. Induction heating of metals and microwave or ultra violet heating of particular materials is an attractive alternative in special cases to general heating in furnaces.

Cogeneration. Cogeneration of heat and work (electricity or shaft power) is offering major opportunities to reduce the cost and fuel consumption involved. Cogeneration is an old technology which is about to enter a period of growth. The established form of cogeneration is steam topping, using steam sequentially to generate electricity and to provide heat for industrial processes or space conditioning. In general, a cogeneration system converts fuel to provide both electricity (or shaft power) and heat (usually steam), the heat being rejected from the initial energy conversion process. Boilers and other heaters where fuel is burned directly to provide low- to moderate temperature heat are relatively inefficient, as shown by 2nd law analysis. In effect, one can view cogeneration as improving the efficiency of heating.

Cogeneration systems which offer substantially higher fuel savings than steam topping are diesels, gas turbines, gas-steam turbines (combined cycle), and, in the longer-term, fuel cells, These alternatives are distinguished from steam-topping by producing a relatively high ratio of electrical to steam energy, while steam topping is a low E/S technology. These alternative technologies have high fuel savings because of their high E/S ratio. A feature of high E/S ratio cogeneration is that it can be adopted in plants with only moderate steam needs. Another feature of the high E/S ratio facility at an industrial site is that, for many plants, some electricity has to be exported. Important areas of development are fluidized-bed combustors and medium Btu gasifiers to enable use of coal for gas turbines.

Motors. Another partly developed technology which may have a major impact on industrial energy is motor controls. Although small motors are often remarkably inefficient, most industrial motors are highly efficient in themselves. Usually, however, the task of such a motor is to move material, not simply to turn a shaft; and in most industrial applications the efficiency of material motion achieved by the motor is low because of the way in which control is achieved.

For example, fluid moving systems are usually over-powered and motion is controlled by throttling. A study of sample systems in British industry revealed typical efficiencies of about 30%. Solid state devices are being introduced to control the motor speed, with the potential of obviating much of this waste.

Energy Management

Most of the 10 to 20 percent reduction in industrial energy use per unit of aggregate production (1972-78) has been due to shifts in the overall mix of products, e.g., from goods to services, and to energy management. There are many opportunities to control energy costs through zero-investment managerial actions or through low-investment, high-payoff actions. Major activities are:

1) Establishment of management procedures, including:
   - o Training programs for operation of energy intensive equipment
   - o Improved maintenance programs
   - o Accounting procedures to charge energy cost to production departments, not to general overhead, and
2) Low-level investment programs which may include:
   - o Direct metering of major energy-using facilities
   - o Sophisticated inspection and maintenance equipment such as infra-red scanners
   - o Automatic control of energy intensive equipment (e.g., turning equipment on and off
   - o Implementing more sophisticated automatic controls to optimize complex utility systems and to optimize performance of devices (e.g., with respect to changing load.
   - o Sophisticated evaluation of downstream operations to optimize use of energy-intensive equipment
   - o Low-cost improvements in energy equipment such as improved insulation, efficient lighting and simple heat recovery devices.

There is much anecdoted but no systematic information as of this date on the extent of energy management opportunities to reduce energy costs and on the

extent to which such opportunities have already been exploited. Well managed firms with technical expertise have achieved savings on the scale of 20% and more and further improvements will require more effort and ingenuity. It is clear that many important opportunities remain in both energy intensive and light industries.

FUTURE PROJECTIONS

In this section, we project the total energy consumption in the industrial sector by examining certain macro-indicators like GNP, value added in manufacturing sector and production in physical terms of certain basic materials. All these are used as surrogates to assess the contributions of certain very general energy services to the total energy consumption for the individual sector. Energy-conversion efficiency and energy management contributions are represented by estimates of aggregate efficiency improvements for the major service categories for this analysis. Process change impacts are not explicitly considered; they justify what may be viewed as optimism about the assumed efficiency improvements.

Data on energy service demands and economics of providing these services at various levels of improved efficiency are still very poor and sparse. Because of the lack of data and general lack of understanding of industrial decision making in the specific area of energy productivity investments, it is inappropriate at this date to project industrial energy needs over a 24 year horizon by means of a detailed microeconomic analysis (despite our orientation towards this approach).

Our analysis is based on the following broad categories:

- Process Heat
- Mechanical Drive
- Chemical and Metallurgical Feedstocks
- Electrolytical Processes
- Industrial Space Heating

As emphasized throughout, the opportunities for productivity improvements are specific to the end use. The analysis, therefore, must be separately carried out for each end use, or energy service. Table 1 shows the 1976 industrial energy consumption in terms of the above categories.

TABLE 1
MANUFACTURING ENERGY USE, TOTAL BY MAJOR MANUFACTURING ELEMENT AND SERVICE CATEGORY (1976).

(10^{12} Btu)

	Element							All Mfg.	
SIC	20	26	28	29	32	33		20-39	
Service Category	Food	Paper	Chemicals	Petroleum	S, C, & G	Metals	Other		%
Mechanical Drive	340.	835.	1,457.	476.	495.	1,532.	2,170.	7,305.	28.3
Electrolytic Processes			411.			1,011.		1,512.	5.9
Process Heat	751.	1,897.	2,248.	2,885.	1,103.	1,475.	1,557.	11,905.	46.1
Space Heat	30.	35.	14.		25.	42.	242.	388.	1.5
Chemical Feedstock			2,290.			81.		2,370.	9.2
Metallurgical Coal						2,321.		2,321.	9.0
TOTAL	1,121.	2,767.	6,420.	3,361.	1,623.	8,453.	5,701.	25,801.	100.0

Source: Adapted from "Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000" Volume 3 - Appendix on Service and Fuel Demands, NTIS Publication.

Table 1

We use GNP, industrial value added or growth in material tonnage to project the various categories of service demands. The final aggregate fuel demand is then modified by the estimated improvements in the energy efficiency for each service by accounting for contributors from equipment improvements, cogeneration and energy management. For this analysis, the GNP growth rate is assumed to be 2.4% per annum. The past trends of the declining share of industrial value added in the GNP is translated as:

$$\text{Growth in industrial value added} = \text{Growth in GNP}$$

1.0% per annum (p.a.) = 1.4% p.a.

Finally, the demands for basic materials, whose share of the energy consumption accounts for about 80% of the total for manufacturing, also has trends towards shifting from goods to services. Similarly, there are shifts in the goods sector from massive products (epitomized by steel rails) to lightweight, sophisticated products such as thin, high-strength sheet steels and electronic devices. Figure 3 shows a time series plot of pounds per (constant) dollar of industrial value added for some of the basic materials.

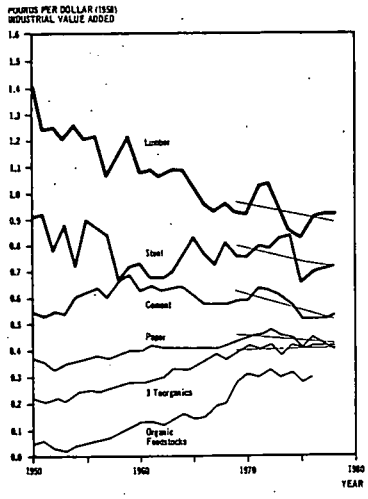


FIGURE 3
CONSUPTION OF BASIC MATERIALS

Linear regression fits for these trends between 1969 and 1978 yield the following product consumption trends (per unit of industrial value added):

TABLE 2

Weighted Average Materials Production, 1969 - 1978

Product	1974 Energy Use (Quads)	Product Consumption Trend[a] (% p.a.)
Steel	5.0	-1.3%
Cement[b]	1.6	-2.1%
Paper	2.7	-0.6%
Chemicals	6.4	+0.4%
	Average	-0.6%

[a]Based on tons per industrial value added (in constant 1958 dollars). (Instead of Federal Reserve Board indices, Commerce Department's Industrial Gross Product is used as a measure of value added.

[b]In the stone, clay and glass group, SIC 32.

Source: Statistical Abstracts and Survey of Current Business.

For the present analysis, we have taken a conservative trend of 0.5% decline in the total average tonnage of basic material with respect to the industrial value added growth of 1.5%, i.e.,

$$\text{Production Growth in Basic Materials Tons} = \text{Growth in Industrial Value Added} - 0.5\% \text{ p.a.}$$

$$= 0.9\% \text{ p.a.}$$

Table 3 below shows the growth indicators used for projecting the energy demand in each service category from 1976 to 2000. The second column indicates which of the three, GNP, Industrial Value Added (IVA) or Materials, is used for the individual service. The last column in this table portrays the aggregate projected efficiency improvement factor for each service.

TABLE 3

ECONOMIC INDICATORS FOR THE GROWTH OF DEMAND IN MAJOR ENERGY SERVICE CATEGORIES AND PROJECTED EFFICIENCY IMPROVEMENT FACTORS, 1976-2000

Service Category	Estimated 1976 Demands	Growth Indicator	Growth, % p.a.	Projected Efficiency Improvement Factor (% Reduction, p.a.)
Mechanical Drive	7.30	IVA	1.4	0.6
Electrolytic Processes	1.81	GNP	2.4	0.75
Process Heat	11.90	Materials	0.9	1.60
Space Heat	0.888	IVA	1.4	1.50
Chemical Feedstocks & Metallurgical Coal	4.69	Materials	0.9	0.75

In Table 4 below, these growth and efficiency improvement factors have been compounded for the 24 year time period which, when multiplied by the 1976 energy demand give the projected demand for the year 2000.

TABLE 4

ENERGY DEMAND PROJECTIONS FOR THE YEAR 2000, BY MAJOR SERVICE CATEGORY

Service Category	1976 Demand (Quads)	Composite Growth Index (1 + Growth Indicator, % p.a.)[n]	Composite Efficiency Index (1 + Efficiency Factor, % p.a.)[n]	Year 2000 Demand (Quads) 1 x 2 x 3
Mechanical Drive	7.30	1.396	0.86	8.82
Electrolytic Processes	1.51	1.767	0.75	2.00
Process Heat	11.90	1.240	0.68	10.03
Space Heat	0.388	1.396	0.70	0.38
Chemical & Met. Feedstocks	4.69	1.240	0.835	4.85
Total	25.79			26.08

The rationale for the economic growth indices (column 3 in Table 4 above) are also considered reasonable in view of the presently known technological improvement possibilties. Let us consider process heat category as an example. The projected demand for the year 2000 is 11.90 x 1.24 quads. We assume net fuel savings from cogeneration to equal 1.0 quad, which approximately corresponds to a 4 quad steam and electricity cogeneration and an overall 25% fuel effeciency improvement. The remaining projected savings 13.75 - 10.03 = 3.72 quads or about 32% improvement can be attributed in the following manner:

Improvements from furnace/heater (including better insulation, etc.)	5%
Improved Management (maintenance, on-off controls, etc.)	5%
Waste Heat Recovery	10%
More sophisticated Controls (Improved air-fuel ratio, optimization for variable load and with respect to downstream operation)	10%

Or, composite savings = 0.95 x 0.95 x 0.9 x 0.9 = 0.73.

It is our view that these levels of energy efficiency improvements are consistent with the expected rise in real energy prices and the present national policies.

Thus, in summary, this paper has developed a logical framework for viewing various components which contribute to the total energy conservation in the manufacturing sector. The analysis in the last section shows that the shifting product patterns and energy efficiency improvements over the next 24 years can sustain a GNP growth rate of 2.4% p.a. by a marginal increase in the total energy use of less than 1 quad.

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INDUSTRIAL-CONSERVATION-TECHNOLOGY ENERGY-SAVINGS MONITORING SYSTEM

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ABSTRACT

A system is described which monitors actual market penetration and energy savings of Department of Energy sponsored industrial conservation commercial technologies. The procedure to implement a new technology into the Impact Scoreboard System (ISS) is described. Included are examples of the implementation steps using two industrial conservation technologies, a ceramic recuperator and a textile foam finishing technology. The paper concludes with a summary of the system benefits to government and industry.

BACKGROUND AND PURPOSE OF THE IMPACT SCOREBOARD SYSTEM

During the past four years, Argonne National Laboratory and the Department of Energy through the Office of Industrial Programs has sponsored the research, development and demonstration of new and retrofit industrial energy conservation technologies.[1] These technologies, once proven technically and economically feasible, are available for adoption by private industry for use in their industrial operations. At present, there are a number of commercially available technologies. Many more are scheduled to be commercially available within 2 years. Thus far, no system exists to track or monitor the progress of DOE technologies that are becoming commercially available.

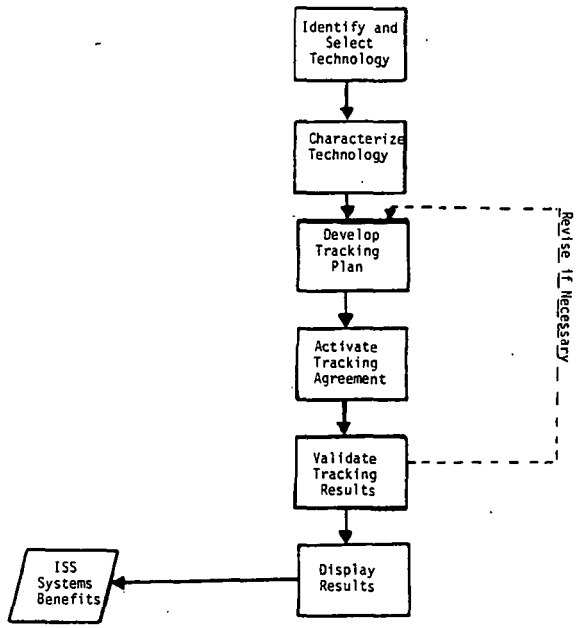
To fill DOE's need to identify the relative success of its industrial conservation technology program, the Industrial Conservation Impact Scoreboard System (ISS) was developed. The purpose of the system is to provide a methodology for collecting and reporting data relative to national and regional energy impacts as conservation technologies become commercial.

SYSTEM OVERVIEW AND DESCRIPTION

Figure 1 presents a schematic representation of the procedure required to implement a technology into the ISS so that the technology's energy savings and market penetration can be monitored. The following discussion will identify each activity in terms of the process step's purpose and description. It will also identify each activity in terms of the application of each step as it relates to the pilot scale implementation of two technologies, a ceramic recuperator developed by GTE Sylvania and a textile foam finishing technology developed by United Merchants and Manufacturing.

FIGURE 1

TECHNOLOGY PROCESS FLOW



1. Technology Identification

The purpose of identifying the near-term technologies is to prepare those technologies which are expected to be commercial first. In order to arrive at the identification of the potential candidate technologies for ISS implementation, an analysis of DOE technologies was necessary. Figure 2 lists the current technologies and their estimated date of commercialization.

2. Technology Characterization

A technology must be defined in terms of its technical characteristics. By defining the technical parameters of a technology, we may analyze how it functions and what is it supposed to do. The tech-

FIGURE 2

IP PROJECTS BY TYPE OF TECHNOLOGY AND ESTIMATED DATE OF COMMERCIALIZATION

INDUS Code	Project Name	Estimated Date of Commercialization*
	Hardware	
7	Paint Curing Ovens	1
12	Granulated Ammonia	1
33	Ceramic Cross Flow	1
34	Metallic Cross Flow	1
78	Paper Sludge Drying for Fuel	1
193	Tank Vapor Control	2
158	Acceptable Sterile Milk	3
199	Shrimp Locator	3
14	Boiler Fuel Controls	3
50	Slot Forge Furnace	3
6	Microwave Drying	4
10	Continuous Steel Reheating Furnace	4
123	Welding Power Supply	4
135	Polywaste to Fuel Oil	4
197	Heat Pump Grain Dryer	4
237	Irrigation Instrument System	4
238	Hydrodynamic Turbine Impeller Redesign	4
257	Leather-Chrome Analysis	4
	On-Site Modification	
11	Cupola Furnace Modification	1
8	Textile Process Modification/Dye	2
205	Paper Drying	3
217	Corn Drying	4
	Process/Production Change	
21	Pulp Fiber Characterization	2
93	Foam Dyeing Textiles	2
182	Shell Egg Cleaning	2
19	Blended Cement	3
32	Energy Monitoring-Petro. Ref.	3
45	Textile Drying Modification	4
101	GASPAK	4
106	Poultry Processing	4

*1 - January through June 1980
2 - July through December 1980
3 - January through June 1981
4 - July through December 1981

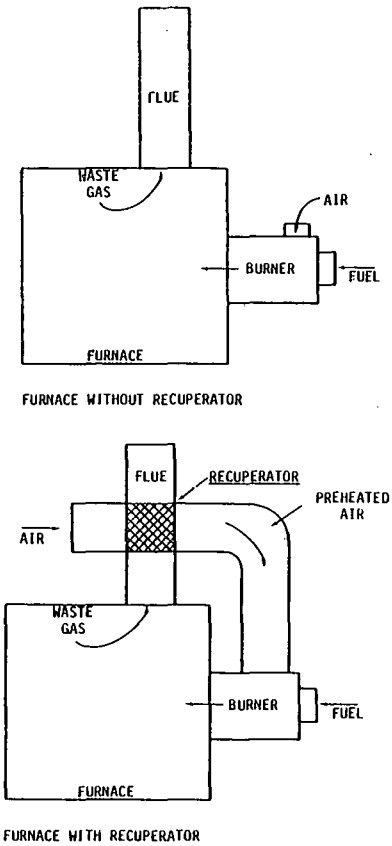
nology is then defined in terms of the system in which it functions. For example, the ceramic recuperator operates in a combustion environment (furnace) that functions by recovering waste heat over a specific heat transfer surface (ceramic core), and preheating the combustion air in the furnace, thereby decreasing the fuel input necessary to bring the furnace to its desirable operating temperature (see Figure 3).

Once we have defined the technology, its functions and its environment, we are able to perform a comparative analysis. Given the same operating conditions, the difference between the fuel input to the system with the new technology and the fuel input without the new technology is the energy savings directly attributable to the application of the new conservation device. The system is analyzed in terms of mass and energy balances in a manner similar to the following example using the ceramic recuperator.

In a typical furnace operating without a recuperator, the combustion products enter the furnace, transfer energy to the material in the furnace with some radiation losses through the furnace walls. They exit from the furnace at approximately the furnace temperature and are exhausted from the stack. Consider an example of a furnace operating at 2000°F on natural gas at 10 percent excess air (Figure 4). The exhaust gases at approximately 2000°F exit through the stack without recuperation. Assume that the input to the input to the furnace is one million BTU/hr.

FIGURE 3

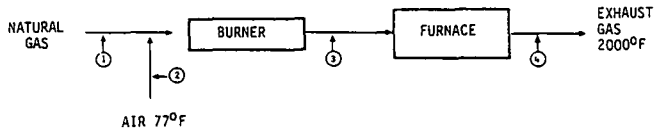
RECUPERATOR APPLICATION



SOURCE: SCI

FIGURE 4

FURNACE WITHOUT RECUPERATOR



A mass balance can be performed on the system as follows:

$$m_1 + m_2 = m_3 = m_4 \quad (1)$$

where: m_1 = mass of natural gas entering burner (point 1)

m_2 = mass of air entering burner (point 2)

m_3 = mass of products entering furnace (point 3)

m_4 = mass of exhaust gas exiting furnace (point 4)

The equivalent energy balance equation for the furnace configuration in Figure 4 is:

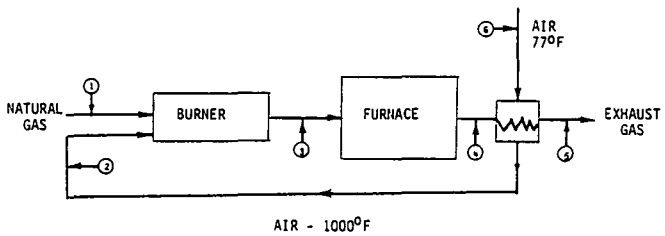
$$m_1 h_1 + m_1 \Delta H_R + m_3 h_3 = m_4 h_4 - Q \qquad (2)$$

where: m = mass rate of flow (lb/hr)
h = enthalpy (BTU per pound)
ΔH_R = heat of combustion of fuel
Q = heat lost in furnace to heat the load and to account for radiation losses

Using the figures in the example and equations (1) and (2), it can be determined that 41.4 lbs. per hour of methane can be combined with 784.6 lbs. per hour of air to produce 826.0 lbs per hour of exhaust gases. The energy wasted up the stack is approximately 602,000 BTU per hour or 60 percent of the furnace input. The other 40 percent is used to heat the production material in the furnace and account for furnace radiation losses.

Now consider a ceramic recuperator installed in the exhausted gas stream (Figure 5) that preheats the combustion air to 1000°F.

FIGURE 5
FURNACE WITH RECUPERATOR



A mass balance for the overall system would give the following equations:

$$m_2 = 18.97\ m_1 \text{ (with 10\% excess air)} \qquad (3)$$
$$m_1 = m_2 = m_3 = m_4 = m_5 \qquad (4)$$
$$m_2 = m_6$$

An energy balance would give the following three equations:

$$m_1 h_1 = m_1 \Delta H_R + m_2 h_2 = m_3 h_3 = 19.97\ m_1 h_3 \qquad (5)$$
$$Q = m_3 h_3 = m_4 h_4 \text{ or } Q = 19.97\ m_1 (h_4 - h_3) \qquad (6)$$
$$m_2 h_2 - m_6 h_6 = m_4 (h_4 - h_5) = 19.97\ m_1 (h_4 - h_5) \qquad (7)$$

where: m = mass rate of flow (lb/hr)
ΔH_R = heat of combustion of the fuel (for methane H = 910 BTU/ft^3 = 21,500 BTU/lb)
Q = furnace load and radiation losses

In this example, introduction of a recuperator with the furnace heat input kept constant, a decrease in fuel consumption of 15.5 percent results for the same 10 percent excess air usage. Methane consumption is now 35 lb/hr, with air 665.0 lb/hr at 1000°F resulting in 700 lbs/hr of exhaust gases. The energy wasted up the stack is now considerably less at 375,000 BTU/hr or 37.5 percent of the furnace input.

3. Tracking Plan Development

This activity consists of the development of a data collection system which will monitor and validate units in use and energy savings by location. Specifically the tracking plan will consist of:

- An evaluation of alterantive collection approaches;
- A definition of data requirements for collection and validation;
- The development of data collection forms;
- The selection of a data source; and
- An identification of responsibilities.

The development of the tracking plan is necessarily technology specific; however, an example of tracking plan development using the ceramic recuperator may be instructive.

One system for determining the annual energy savings resulting from the introduction of a ceramic recuperator in an industrial furnace operation is to meter the fuel input to the furnace before and after the use of the conservation devices. A difficulty of this approach is that in many industrial plants individual furnace full consumption may not have been monitored on a continuous basis, and metering individual burners would prove extremely expensive.

Furnace operators usually do not follow set furnace operating specifications, and fuel and excess air usages vary considerably depending on each individual application and the particular furnace load. Furnace operators are more concerned with meeting production targets and will do so by adjusting fuel and air inputs to the burner so as to obtain the best operation conditions in the furnace irrespective of fuel economy.

The approach taken in developing a tracking plan is to be able to most reasonably estimate the fuel savings from the introduction of the ceramic recuperator at the least possible cost. The potential user of a ceramic recuperator approaches the vendor for a quotation and provides the vendor with some data on his present furnace operation. The vendor will design and size the recuperator for the given application. If this information is available from the vendor, calculations can be performed to determine the actual fuel consumed per hour when the recuperator is used. If no prior fuel usage data is available, this may be calculated assuming the identical furnace operating parameters with the furnace exhaust gases being directly vented to the stack. The annual fuel savings may then be computed from the actual furnace operating load factor, if available, or an estimated load factor for a typical operation in that particular industry.

Assuming this approach to data collection, the following data would be needed for tracking and validation:

Tracking

- Information on when a recuperator is sold and installed
- The size of the ceramic cube
- The industrial appliation (by 4-digit SIC)
- The location of the industry (specific or by state)
- The type of fuel used in furnace
- The energy consumed by the furnace (per hour at rated capacity) prior to installation of the ceramic recuperator
- The furance load factor by calendar quarter, if operated at other than the rated capacity, or the number of hours of operation.

Validation

- The amount of excess air used in normal operation of the furnace
- Temperature - combustion air inlet
- Temperature - combustion air outlet
- Temperature - waste gas inlet
- Temperature - waste gas outlet
- Rated heat input to the furnace

Some data collection forms were developed to facilitate data collection and verification. In the case of the ceramic recuperator, the manufacturer, GTE/Sylvania, has agreed to provide the data to maintain the ISS. However, such data should be verified to determine whether the energy savings are attributable to the specific technology or attributable to changes in furnace operating conditions which could be obtained irrespective of the introduction of the ceramic recuperator. Should prior fuel consumption data be unavailable, fuel use would be estimated from whatever information is available from the user of the vendor. The following equations are presented in a form that readily allows the calculation of required energy savings.

Before Recuperator

$$\text{Air Fuel Ratio} = \frac{m_2}{m_1} = 17.23\ (1 + x)\ \frac{\text{lb air}}{\text{lb methane}} \qquad (8)$$

Where: x = excess air used
m_1 = mass flow rate of methane (lbs/hr)
m_2 = mass flow rate of air (lbs/hr)
If: H_3 = enthalpy of gases entering furnace or rated furnace input,

$$\text{Then:}\quad H_3 = m_1\ [\,21{,}770 + 2{,}205\ (1 + x)] \qquad (9)$$

Equation 9 will yield the mass flow rate of methane when the furnace heat input and excess air are known.

After Recuperator

$$m_1\ [\,21{,}770 + 17.23\ (1 + x)\ h_2\,] = H_3 \qquad (10)$$

For the same furnace heat input and excess air, the mass flow rate of methane may be calculated if the specific enthalpy of the preheated air (h_2) is known.

$$\text{Amount of Fuel Saved} = H(m_1 - m_1') \qquad (11)$$

4. Tracking Agreement Selection/Application

This activity includes the following:

- Preparation of agreement indicating responsibilities
- Negotiation
- Approval of agreement by all parties
- Initiation of tracking.

The agreement should consist of the following elements:

- Data requirements
- Period of reporting
- Frequency of reports
- Remuneration (if necessary).

The period of performance could be tied to percentage of the market penetration of the tech-

nology. That is, when a technology reaches 50 percent of the total projected market, for example, tracking would cease. Frequency of reporting, generally, would be at the most quarterly and at least annually, depending on the type of technology and the potential rate of penetration. Remuneration will probably not be necessary because industry representatives have been extremely cooperative and have seen the advantages in monitoring and publishing data on market penetration and energy savings.

5. Data Validation

The purpose of this activity is to ensure the quality and integrity of the collected data requirements.

Two approaches are possible for verification. The first method involves calculations developed for the Tracking Plan. This method, based on the required data identified in the Tracking Plan, provides a quick and accurate verification assessment of the accuracy of the data received from the data source.

The second method of verification is on-site analysis of energy flows of a representative sampling of the technology's commercial applications. This method of verification would only be employed if wide discrepancies between the tracking results and the results of the first verifying method exists.

The first approach, calculations, was developed to verify the energy savings attributable to the foam finishing technology. A brief excerpt is provided here presenting the rationale and method of verifying energy savings for the foam finishing technology.

Energy savings estimates should be verified to determine whether the energy savings were attributable to the foam finishing technology or attributable to changes in dryer operating conditions which could occur irrespective of the introduction of the foam process. Should prior fuel consumption data be unavailable, fuel use would be estimated from whatever information is available from the user.

The key feature of the foam finishing technology is that it results in less water being picked-up by the fabric when compared with conventional finishing techniques. Consequently, less water needs to be evaported in the dryer and less energy is used. Foam finishing uses different finishing chemicals than in conventional finishing methods. Some of these chemicals permit a lower curing temperature than with conventional finishing chemicals, and thus further energy savings could result by operating the dryer at a lower temperature. A further benefit of the foam technology is that it permits higher fabric speeds because less water needs to be evaporated in the dryer, thus further reducing the energy required per yard of fabric. All of these factors need to be considered in computing the energy saving due to the foam finishing technology.

The fuel required to dry and condition the fabric is given by:

$$m_1 = y\ W_F\ F_S\ (857.2\ P_W + 41.8) \qquad (12)$$

Where: m_1 = Fuel Flow (BTU/hr)
y = Dry Fabric Weight (oz/yd^2)
W_F = Fabric Width (inches)
F_S = Fabric Speed (yds/hr)
P_W = Water Pick-up (fraction)

Energy savings is the difference between the fuel use in conventional finishing and fuel use in foam finishing. In particular:

$$\text{ENERGY SAVINGS} = \sum Y_i \left[\frac{m_1 - m_1'}{60\ F_S^F} \right]_i \qquad (13)$$

Where: Y_i = Production of Foam Finishing for Category i (yds)
m_1 = Fuel Flow, Conventional Finishing (BTU/hr)
m_1' = Fuel Flow, Foam Finishing (BTU/hr)
F_S^F = Fabric Speed, Foam (yds/minute)

Thus, if the total number of yards of a specific fabric produced per time period (Y) is known, the energy savings can be calculated. Similarly, savings can be computed for each category of fabric (i) to yield the total energy saved by the introduction of the foam finishing technology.

6. Display Preparation

Based on the method of collection decided upon in the Tracking Plan, the display element must be prepared to ensure easy entry of the technology specific data inputs.

Methods of collection can range from questionnaire solicitation, that would require manual input into the display system, to telephone links between the primary data source to the display system allowing direct input of the data requirements into the display element. Data collection must be made compatible with the display system.

The display system will require a comparative data base for each technology by which the actual

energy savings and market penetration may be measured. A preliminary market analysis will probably be necessary to use as a comparative data base.

The ISS display element accepts the data collected through the tracking element, performs necessary calculations and provides an analytical display showing the effectiveness of industrial energy conservation technologies in reducing energy use. System displays can be graphical or numerical comparisons. See examples in Figures 6 and 7.

SYSTEMS BENEFITS

The ISS will provide benefits for both the government and private industry:

Government

- Measure actual energy savings of the new technology;
- Measure actual market penetration of the new technology;
- Identify national and regional technology impacts;
- Enhance program planning/program direction;
- Enhance project selection criteria;
- Justify budget submission;
- Establish cooperative relationships with private industry; and
- Accelerate technology adoption by potential users.

Industry

- Provide proven statistical and operational data related to the conservation device to potential industrial users/decision-makers;
- Provide a feedback mechanism related to technology adoption for use by the manufacturers, distributors, etc.;
- Enhance market strategy planning of technology manufacturers, distributors, etc.;
- Accelerate adoption of energy savings technologies to industrial users; and
- System can be adapted for private industry use.

FIGURE 6

INDUSTRIAL ENERGY CONSERVATION TECHNOLOGY

IMPACT SCOREBOARD

SAMPLE TECHNOLOGY A

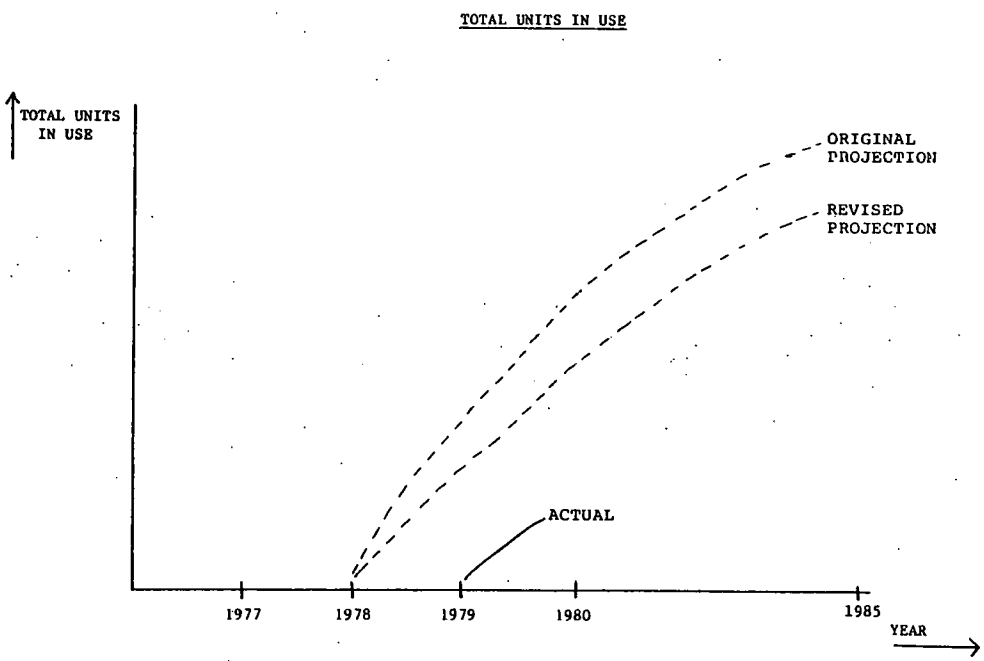


FIGURE 7

INDUSTRIAL ENERGY CONSERVATION TECHNOLOGY

IMPACT SCOREBOARD

SAMPLE TECHNOLOGY A

INDUSTRIAL ENERGY CONSUMPTION INDEX

Region	1975 Base Case	1980 Base Case	1980 With Tech. A Savings
I	24	32	32
II	42	73	70*
III	71	142	142
IV	111	181	179*
V	156	337	337
VI	408	690	690
VII	46	76	76
VIII	28	48	47*
IX	90	167	167
X	23	42	42
U.S. SUMMARY	100	179	177*

*Regions where technology impact is significant

Reference 1

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A LOOK TO THE FUTURE: SOLAR REPOWERING FOR TOMORROW'S ENERGY NEEDS

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ABSTRACT

One provision of the National Energy Act of 1978 is to restrict the use of oil and natural gas in industrial boilers. In order to research methods of providing alternate fuel sources for the boilers, the Department of Energy initiated a program to investigate the technical feasibility and cost effectiveness of central solar thermal energy technology. Projected development of this program includes studies of utility and industrial sites for application and the possibility of constructing one or more demonstration sites. The paper will discuss current solar central receiver technology, specifically outlining a feasibility study of the solar repowering concept by Texas Electric Service Company and Rockwell International.

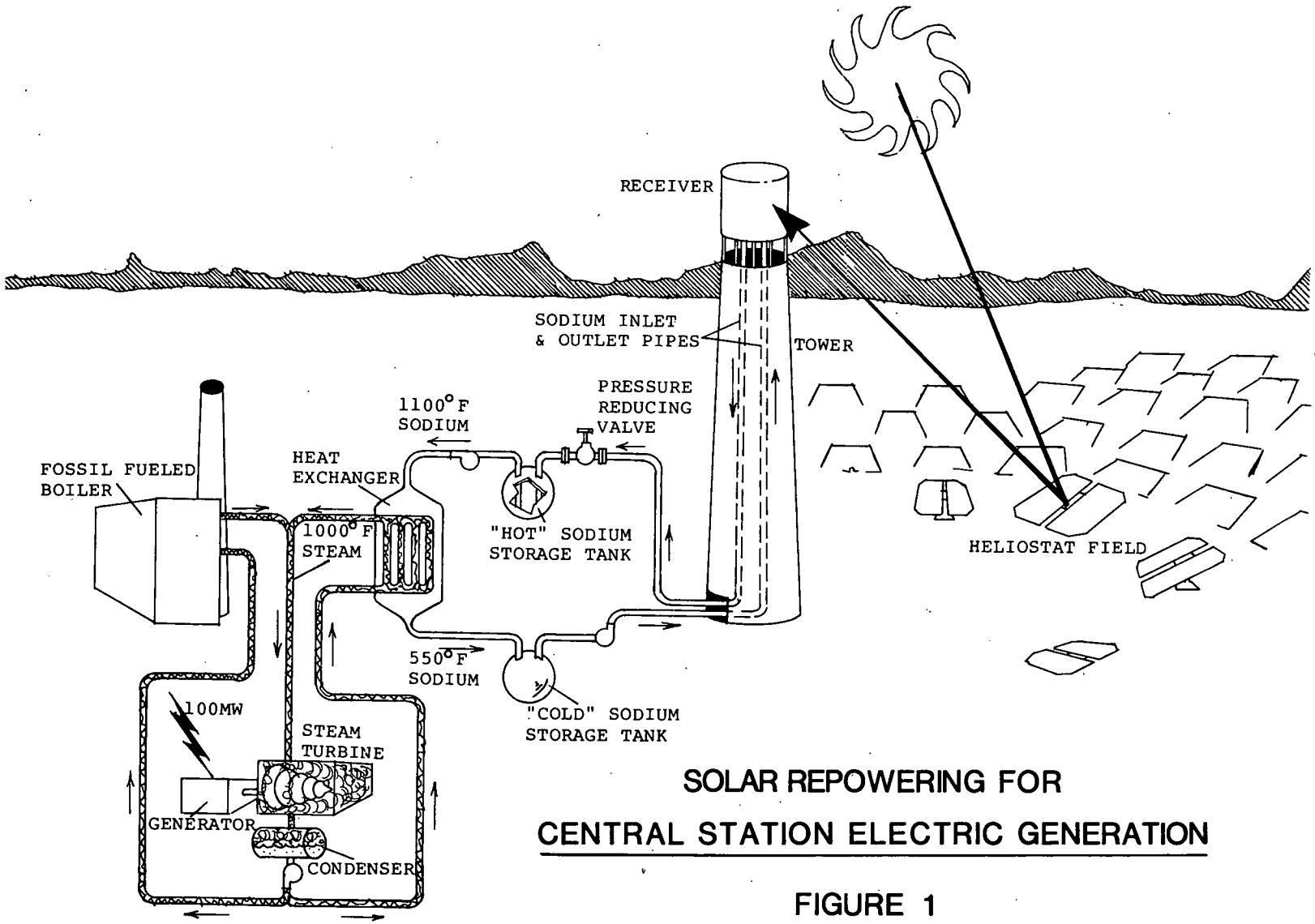
INTRODUCTION

Oil, natural gas, coal, uranium and water are precious natural resources, but, unfortunately, they are either limited or have problems associated with their use. In this new decade we will have to strive to make better use of these resources through their fuller development and through conservation. To further help the nation achieve energy independence, effort is being made to develop renewable energy sources: direct sunshine, the wind, falling water and plant matter.

In this regard, major legislation, including the Solar Energy Research, Development and Demonstration Act of 1974 and the National Energy Act of 1978, has provided impetus and direction for this development. Further, as part of the National Energy Act, the Power Plant and Industrial Fuel Use Act of 1978 restricts the use of oil and natural gas in industrial and utility boilers. Although it will be many years before solar, as an alternate fuel source for these boilers, will provide a meaningful portion of our energy supply, great effort is underway to advance the current technologies. Recent changes in the energy marketplace, together with this advancing technology, have put the practical and economic conversion of sunlight into heat and electricity closer to reality.

The development of solar thermal energy technology is being managed by the Department of Energy through its Division of Solar Technology. The Division's Solar Thermal Program is intended to provide a "sound technological and industrial base which will result in the commercialization of solar thermal technologies and thereby contribute significantly to fossil energy displacement goals by the year 2000."

The program supports the development of systems which receive concentrated solar heat through a reflective process for both electric power generation and industrial purposes. This development receives about 30-35 percent of DOE's Solar Thermal Power Systems budget, with great emphasis being placed on the three main types of collectors being designed for various systems: line focus, parabolic dish and heliostat. Line focus concentrators are striving for high performance concepts with capabilities in the 400°F to 600°F range at the Sandia Laboratories in Albuquerque, New Mexico. Higher temperature (up to 1000° F) linear designs have



SOLAR REPOWERING FOR

CENTRAL STATION ELECTRIC GENERATION

FIGURE 1

also been studied for bulk electric power. Another linear distributed receiver is the fixed hemispherical bowl concept. Testing is underway on a prototype 65-foot diameter module developed by E-Systems in cooperation with Texas Tech University. The test module is intended to validate performance projections and design features of concentrators that comprise a five megawatt solar power plant at a site near Crosbyton, Texas.

Parabolic dishes offer the highest possible optical performance, a high degree of modularity, minimum land use, and high temperature capability ranging wider than troughs and bowls. Dish systems are potentially the most versatile concentrator approach but their size and temperature capabilities will be less than central receivers.

CENTRAL RECEIVER PROGRAM

The most visible effort and the one receiving the most attention is the solar central receiver, central generating station concept which applies to large scale, high temperature needs. This concept utilizes energy directly as process heat or it may be converted to electricity through an electric power generation system. Hybrid concepts combine a solar central receiver with a fossil-fired unit, thereby having the ability to maintain rated output of the plant at all times regardless of the availability of solar energy.

The central receiver, central generating station concept shown in Figure 1 consists of five modules: heliostats, solar receiver, thermal storage system, heat exchanger, and steam turbine/generator. Heliostats, or individually controlled mirrors, are placed in a field surrounding the central receiver tower and reflect the solar energy (sunlight) to the receiver on top of the tower. The two basic types of heliostats are shown in Figure 2 below. The collector is a flat reflecting surface which can either be exposed to the elements or covered with a dome. Each contains approximately 56 square meters of mirror area, and the pivot point of the collector is approximately 4 meters above ground. Each heliostat contains a preprogrammed microprocessor that directs the heliostat

EXAMPLES OF SECOND GENERATION HELIOSTATS

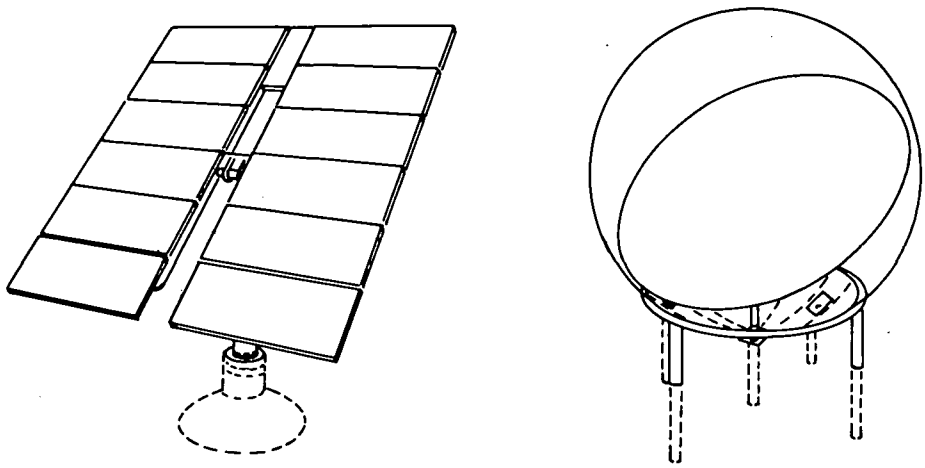


FIGURE 2

controls to follow the sun while a master computer in the plant control room operates the entire heliostat field. The solar portion of the plant is thus controlled during start-up or shutdown and at various levels of power generation. The heliostat field can be either a surround field or a north field. In the surround field, the heliostats are placed in a pattern entirely surrounding the central receiver. Economic studies, however, have concluded that the north field, where the heliostats are placed on the north side of the receiver, is the optimum configuration as long as heliostat costs remain extremely high. Since the sun in the United States is in the southern skies, sunlight strikes the heliostat at an acute angle, as illustrated in Figure 3. With the approximately parallel sun's rays a and b striking the two heliostats, the solar energy from the northern heliostat travels through a much smaller angle with minimal loss before reaching the central receiver. Also, more energy is intercepted and reflected by a given surface area when it is closest to a 90° angle with the incoming rays of the sun.

The solar thermal energy reflected by the heliostats is transferred in the receiver to a transfer fluid. The fluid is pumped through the receiver and heated by the solar energy to cool the receiver and maintain it at design temperature. Of the four heat transfer fluids used, liquid sodium, molten salt and water/steam are heated to approximately 1100° F, while inert gas systems are heated to approximately 1500°F-2000°F. Although inert gases, such as helium and air, are not as adaptable to repowering projects as are the other transfer fluids, they are not corrosive materials and have the advantage of remaining in their same state. In the water/steam concept without storage, steam is generated only as the solar energy is available to each part of the heliostat field, severely limiting the system's usefulness during cloudy days. This results in an erratic operation of the steam turbine because of the constantly changing energy

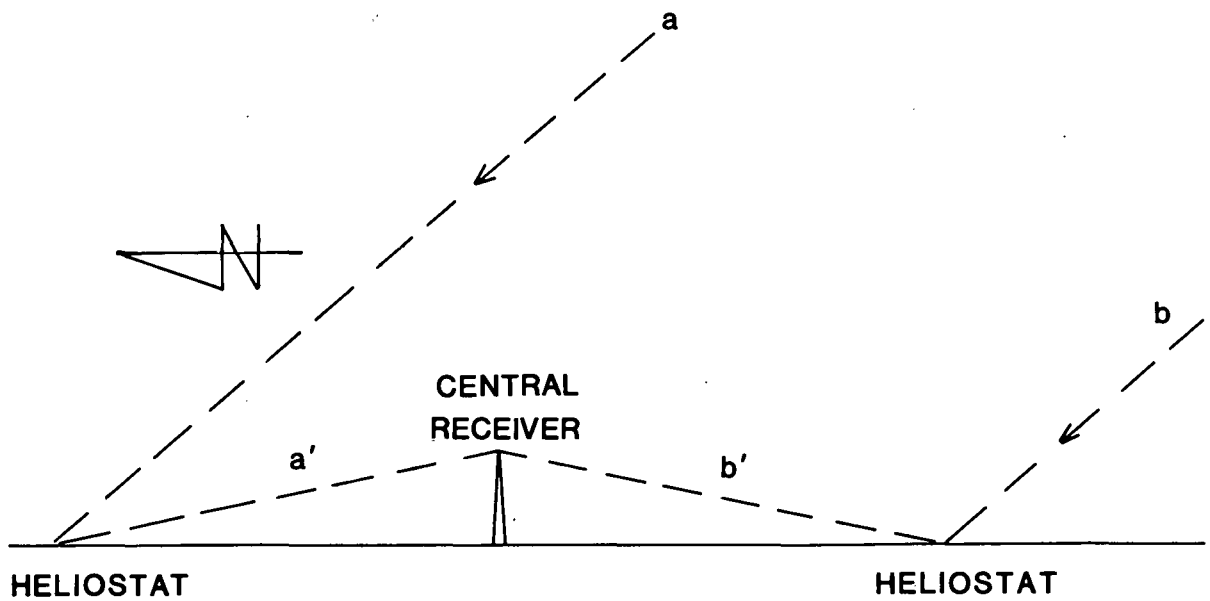


FIGURE 3

output. Thermal storage can be provided, however, to buffer the changes in available solar energy. With thermal storage, part of the steam is directly utilized to produce electricity, while part is stored as energy in the thermal storage tank. The components of the less expensive water/steam concept have been built and tested, and the concept is understood and accepted by utilities.

The operational concepts which use liquid sodium and molten salt are identical. In both, the sodium or salt, each in a liquid state, is moved from the receiver to a "hot" storage tank, pumped to the heat exchanger to produce steam, pumped to a "cold" storage tank and then back up the tower, completing the cycle. Salt has an advantage because it is inexpensive and has been used in the metallurgical industry as a heat transfer fluid for many years. Sodium has an advantage because it absorbs heat faster and retains heat longer than most other chemicals.

As mentioned, a portion of the solar thermal energy can be stored in tanks for later use during cloud cover and at night which adds a dimension of flexibility to these concepts. These well-insulated tanks, having a heat loss of approximately one percent per 24-hour period, allow the solar conversion system to operate at more than 20% capacity factor, a limitation in most of the United States. Although short-term storage is expensive and economical long-term storage is not yet feasible, storage can reduce fossil fuel consumption and buffer the effects of load and insolation transients.

The heat exchanger performs the same function but operates differently in each concept. Using water/steam without solar thermal storage, the receiver is the heat exchanger. The superheated steam flows directly from the receiver to the steam turbine. In the other concepts, the steam generator acts as the heat exchanger, transferring energy from the heat transfer fluid to water which is then converted to superheated steam. This steam is used to operate the steam turbine/generator in the conventional manner.

The central station electric generator has greater flexibility when a fossil-fired steam generator is combined with a solar steam generator. The plant can be fueled by solar, fossil fuel or a combination of both. The solar thermal storage can also be utilized for start-up steam after the plant has been shut down for a period of time up to 45 days.

Methods to reduce the cost of central receiver subsystems and components are being explored. Production and design improvements of heliostats and volume production are essential factors to reduce the cost of heliostats and ultimately the entire system. Heliostats represent both the major cost element in present solar plant designs and the component most amenable to the application of mass production techniques. DOE experts believe installed costs of about $70 per square meter are obtainable for heliostats by 1990 as compared to present costs of $300-$400 per square meter.

An important bridge from R&D to commercial applications is the 10 MWe Solar Thermal Central Receiver Pilot Plant near Barstow, California, which is presently projected to cost $139.5 million. The plant will be a technical demonstration to provide solid data on cost, performance and environmental impact. Even the most powerful analytical tools can not provide the design and operating experience that this plant will furnish to resolve the uncer-

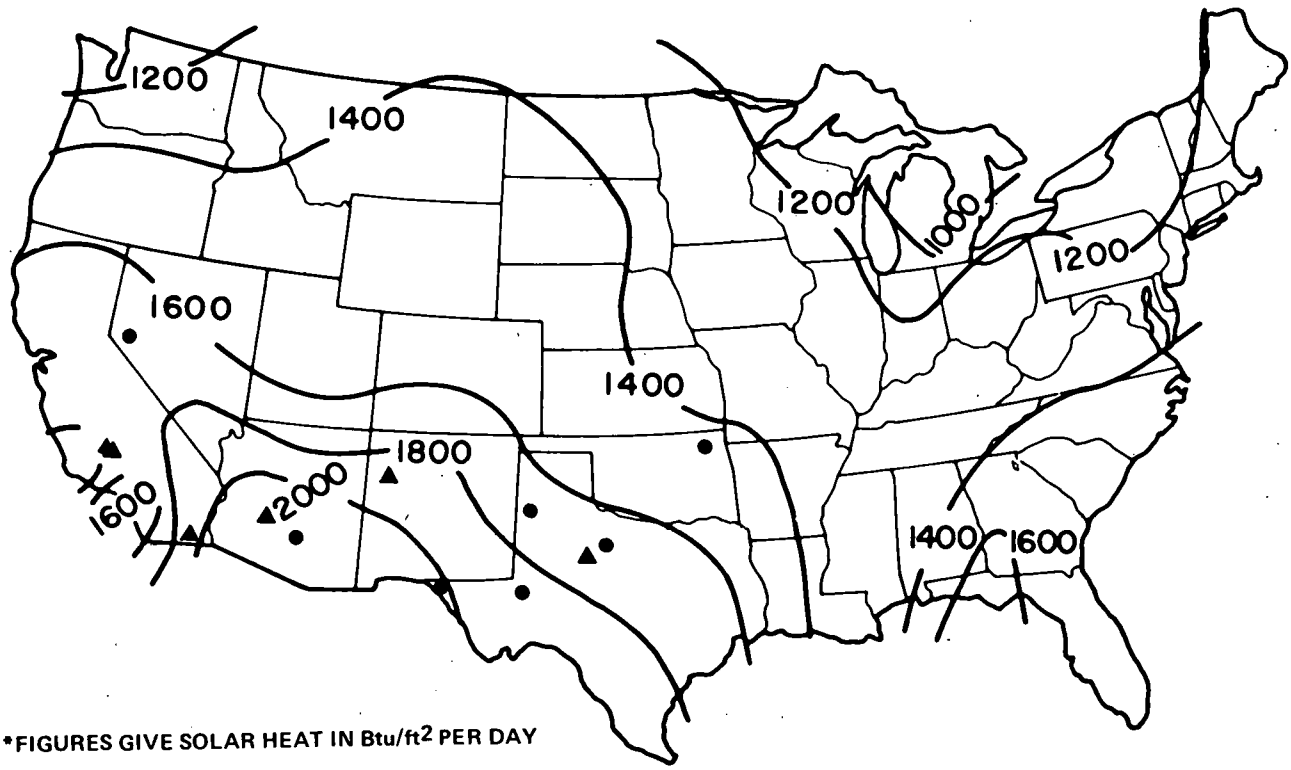
tainties regarding the operational feasibility of solar technology. Begun in 1971 under National Science Foundation funding, Barstow, a first generation project using water/steam as the heat transfer fluid, will generate electric power under field environmental conditions in late 1981. DOE's future solar development efforts will be guided by the technical and economic experience gained from the Barstow Pilot Plant.

CENTRAL STATION SOLAR REPOWERING PROGRAM

One of the key "hardware" milestones on the path to commercialization for central receiver technology is DOE's Repowering Program. "Repowering" means the addition of solar capability to an existing electric generating plant or an indusal process to partiallyor completely replace oil or natural gas as an energy source. The program will provide commercial experience with central receiver hardware, a foundation for realistic economic projections, and a manufacturing base for heliostats and other components. Any remaining technical uncertainties should be resolved and user confidence in central receiver technology increased.

ANNUAL AVERAGE DISTRIBUTION OF U.S. SOLAR ENERGY

WITH SOLAR REPOWERING PROJECTS



*FIGURES GIVE SOLAR HEAT IN Btu/ft^2 PER DAY

▲ PROCESS HEAT
● UTILITIES

FIGURE 4

Repowering projects, which are commercial demonstrations of solar technology, evolved from a study performed by Public Service Company of New Mexico (PNM) in 1977-78. This technical and economic assessment included the conceptual design of a typical solar hybrid repowering project and supplied valuable data from which to build a Repowering Program strategy. The MITRE Corporation examined the commercial market for solar repowering and found it to be in the regions of highest insolation, the Southwest, as illustrated by Figure 4. The market here is greater than 26,000 MWe for utilities and 22,000 MWt for chemical and petroleum industries, based on the availability of existing plants.

DOE, intending to reduce central receiver technology to practical, commercial applications through its Repowering Program, solicited multiple design efforts from industry under RFP DE-RP03-79S-F10506 for Solar Repowering/Industrial Retrofit Systems in March, 1979. The object of this solicitation was to develop site specific conceptual designs that have the potential for construction and operation by 1985, make maximum use of existing solar technology, and provide the best possible economics for the overall plant application. Conceptual designs for proposed projects will include the solar plant addition, performance parameters, definition of basic subsystem requirements, basic economic analyses, identification and resolution of regulatory and environmental issues, development schedule, management strategy, and cost estimates. In all of the proposed projects, the user selected the solar central receiver concept most appropriate for the user's proposed application, site and existing facilities.

Response to the RFP was significant, thirteen utility applications and nine industrial; and in October, 1979, twelve contracts were awarded by DOE for feasibility studies. Repowering conceptual studies will be made by the following partners:

Arizona Public Service Company/Martin Marietta Corporation - molten salt; Tucson, Arizona

Black & Veatch Consulting Engineers/Public Service Company of Oklahoma - water/steam; Tulsa, Oklahoma

El Paso Electric Company/Westinghouse Electric Company - water/steam; El Paso, Texas

General Electric Company/Southwestern Public Service Company - liquid sodium; Earth, Texas

McDonnell Douglas Astronautics Company/ Sierra Pacific Power Company - molten salt; Yerington, Nevada

Texas Electric Service Company/Rockwell International - liquid sodium; Monahans, Texas

A less detailed study, approved but not funded by DOE, will be made by West Texas Utilities Company and Rockwell International. Industrial retrofit conceptual studies will be made by the following partners:

Boeing Engineering & Construction Company/ U.S. Gypsum Company - gypsum board drying; Sweetwater, Texas

Foster Wheeler Development Corporation/ Provident Energy Company - oil refinery; Mobile, Alabama

Martin Marietta Corporation/Exxon Corporation - enhanced oil recovery; Bakersfield, California

McDonnell Douglas Astronautics Company/Gulf R&D Company - ore separation; San Mateo, New Mexico

Northrup, Inc./ARCO Oil & Gas Company - natural gas refinery; Bakersfield, California

PFR Engineering Systems, Inc./Valley Nitrogen Producers, Inc. - ammonia/fertilizer; El Centro, California

PERMIAN BASIN FEASIBILITY STUDY

Texas Electric believes it is important to explore all available energy alternatives to ensure customers a reliable supply of electricity now and in the future. Because conversion of an existing generating unit to solar energy has never been attempted, Company management feels the nine-month feasibility study can help answer many questions, although no actual construction is involved.

Preliminary information indicates the Permian Basin area in West Texas is particularly suitable for solar energy application. The Permian Basin Plant, shown on Figure 5 which illustrates the Texas Electric Service Company System is located four miles west of Monahans. It is an area

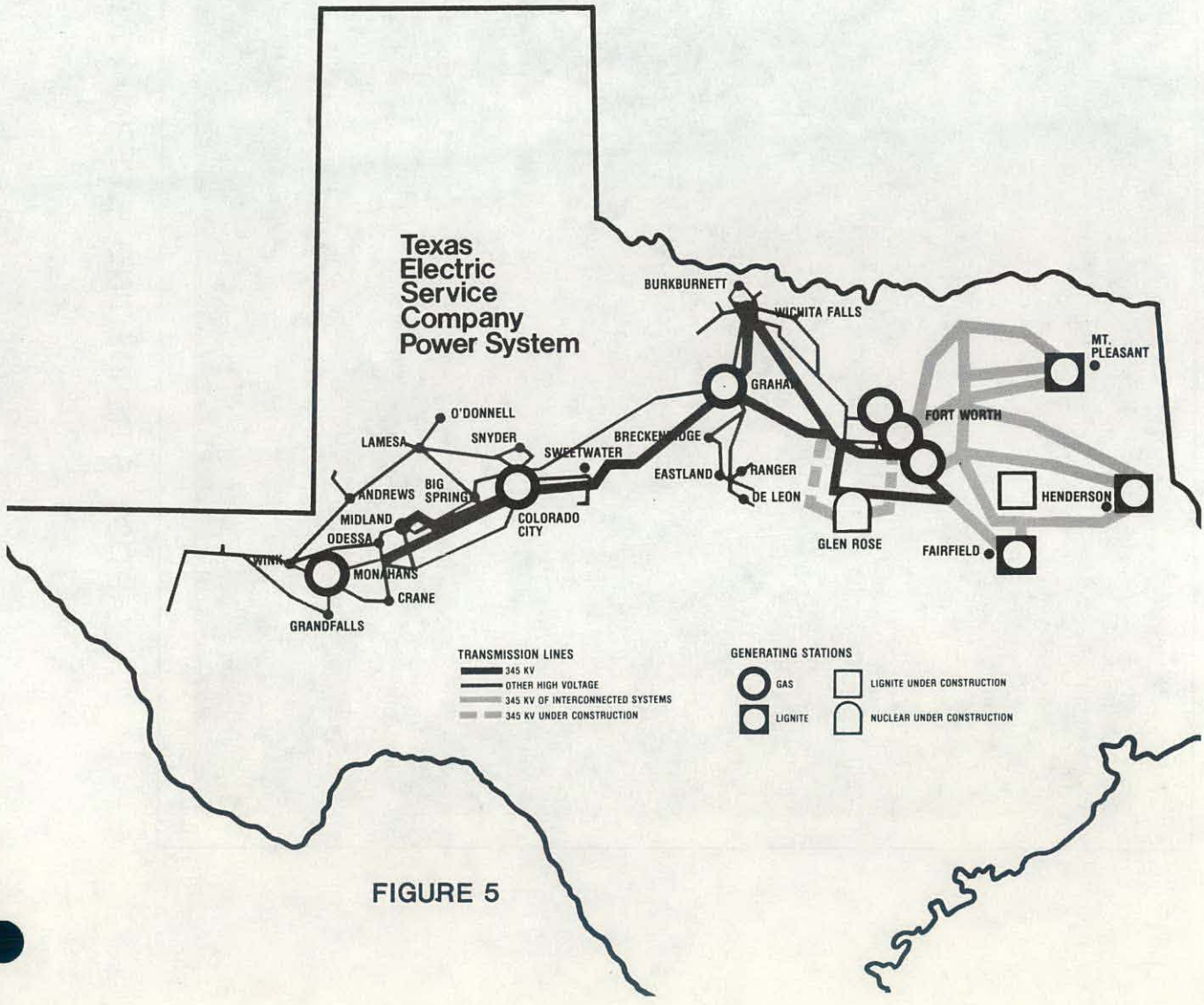
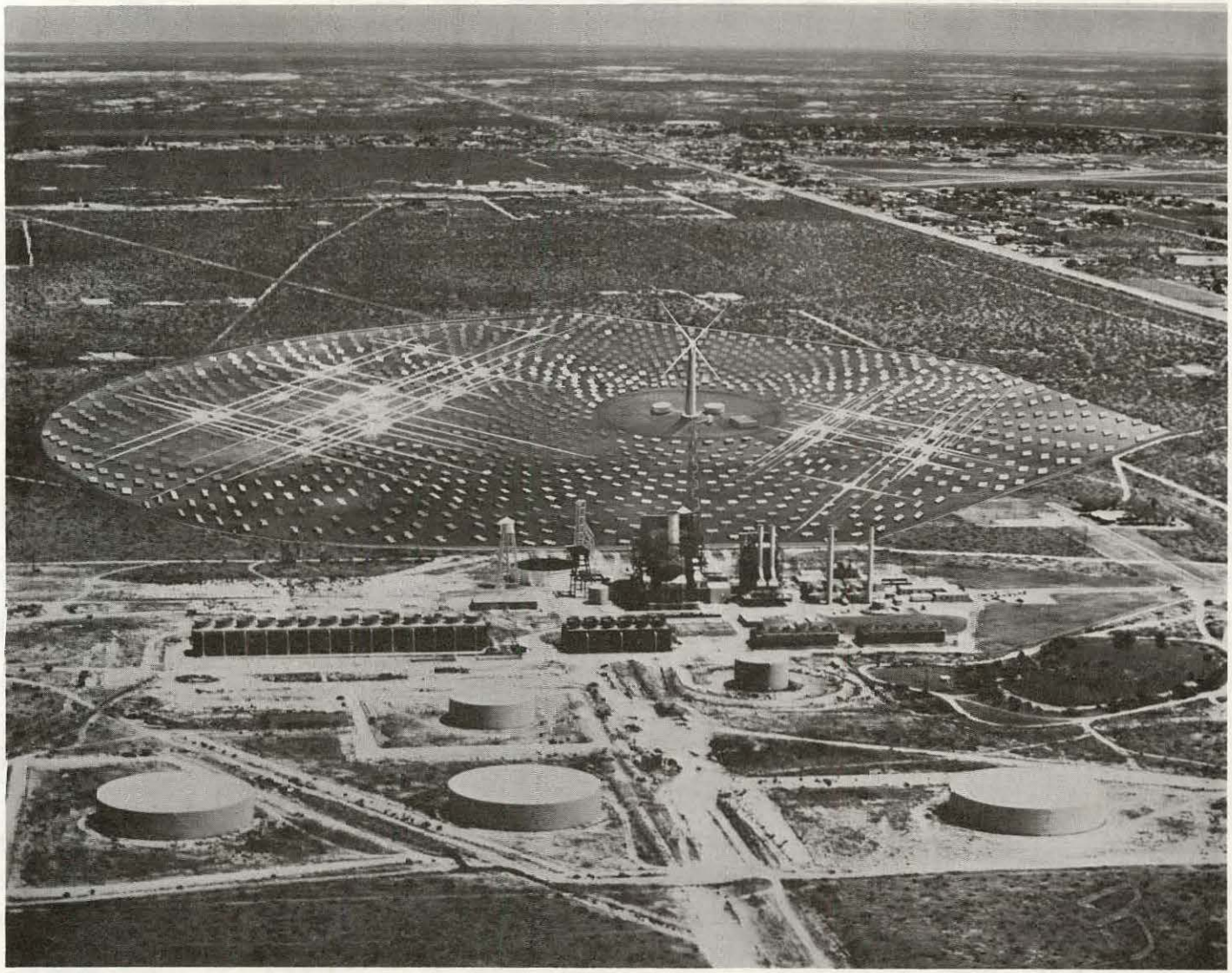


FIGURE 5



ARTIST'S RENDERING - PERMIAN BASIN PLANT

which realizes maximum solar energy, an equivalent f 1850 Btu/ft^2/day. The 115 MW net output of the Permian No. 5 unit is a good size to study the technical feasibility of solar repowering.

To submit a site specific proposal, a team of companies was assembled with TESCO participating with Rockwell International, the prime offeror. Another team member, McDonnell Douglas, will develop the heliostat design. Stearns Roger, an architectural engineering firm, will design the interface between the existing plant and the solar equipment. The University of Houston will develop the computer programs for use in optimizing the configuration of the heliostat field.

Permian Basin Unit No. 5 is a natural gas-fired unit which uses fuel oil as standby fuel. The unit's superheat temperature is 1005°F at 1516 psi; the reheat temperature is 1005°F at 471 psi. Initial studies indicated the best configuration of the unit would be 100 MW of available capacity, which would include 40 MW of base load generation and 60 MW of solar generation. The receiver tower, utilizing the most economical construction of steel I-beams and angle shapes, is projected to be 101 meters tall. Placed on top of the tower will be the 12-meter high receiver which will use liquid sodium as the heat transfer fluid.

The artist's rendering shows the projected layout of the heliostat field superimposed on an aerial photograph of the existing plant site. Approximately 5000 heliostats will be required to produce the current design level of 50 megawatts of electrical output with one hour of thermal storage. The 56-square meter heliostats will require 250 acres of land which is already available at the Permian Plant. This is about 3.75 times more than the 68 acres of actual heliostat surface so that the heliostats can track the sun without reflecting off the one directly in front. This also allows for maintenance.

The "waterfall chart" (Figure 6) illustrates the system losses that would occur during the generation process at Permian Basin Plant. The total efficiency of converting normal thermal incident solar energy to net electrical energy output is 22%. Peak solar energy incident on the heliostats at summer solstice is 255 megawatts thermal. Losses caused by inaccurate aiming of the heliostat, spillage of energy reflected upon the receiver, atmospheric attenuation, cosine effect, and blocking and shading of the heliostats total 75 MWt. Losses at the receiver as a result of energy reflection, radiation, convection, and the pumping power required to raise the sodium up the tower total 25 MWt. Additionally, 30 MWt is placed in storage, while the conversion of thermal heat to steam to electricity accounts for 75 MW thermal loss. The various steam turbine pumps and operating power for the heliostat field account for the final 5 MW electric loss.

Project costs, subject to revision, are estimated to be $105 million in 1980 dollars, or $2360 per kw net output. The largest portion of this cost is $74 million, the installed cost of the heliostat field, with each heliostat estimated at $230 per square meter. A two-third reduction in heliostat cost in the future is anticipated as a result of mass production. The central receiver and storage system is estimated at $22 million, with the balance appropriated for engineering design and interface with the existing plant.

DOE is expected to issue a Program Opportunity Notice (PON) to solicit detailed construction designs for one or two utility sites after the fea-

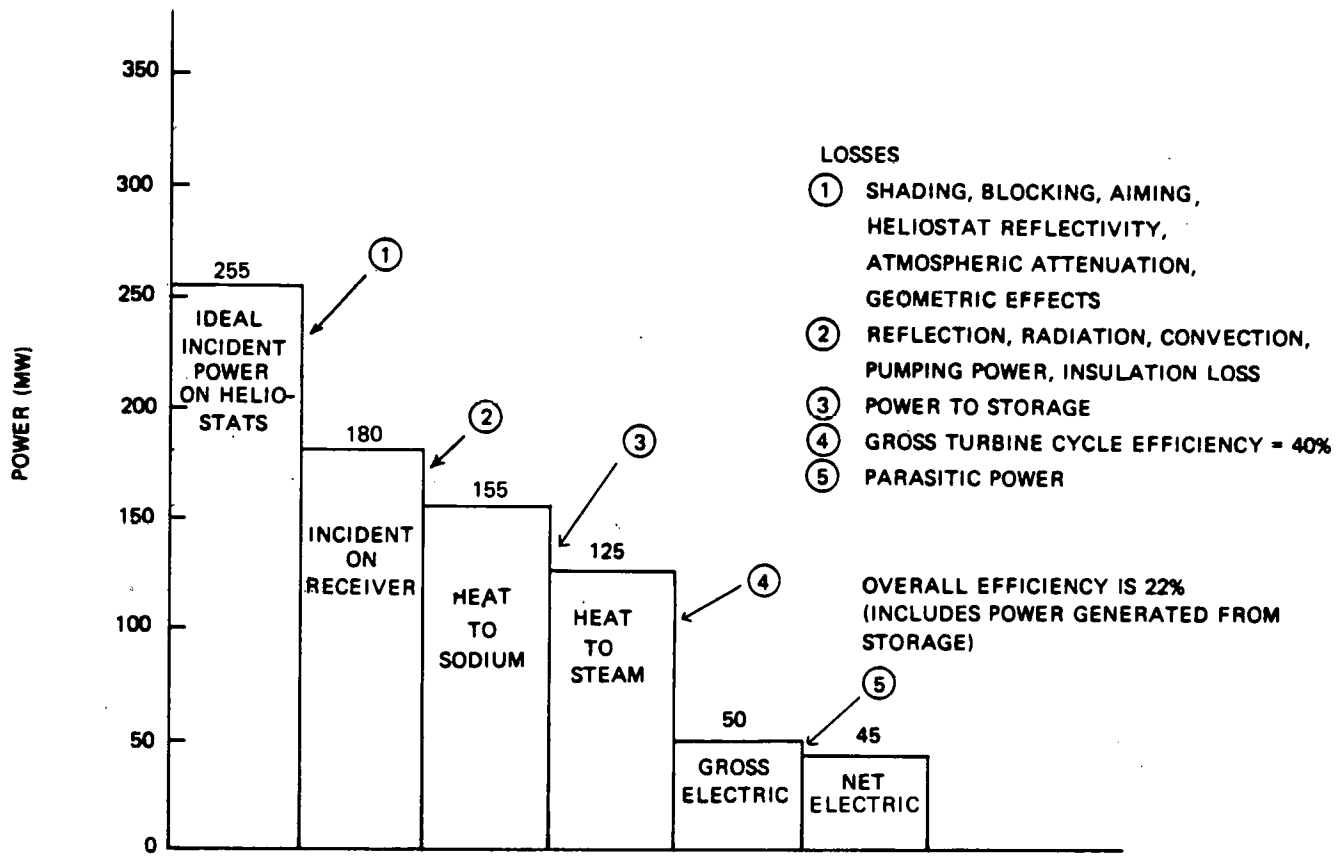


FIGURE 6

sibility studies are complete in July, 1980. Site selection would not be limited to the sites presently being studied. Conceivably, a construction contract could be awarded in January, 1981, with construction completed and the plant beginning a five-year test operation by February, 1985.

The Department of Energy anticipates a strong emphasis in the future development of central station generation from solar energy. This central station emphasis is now in the area of solar repowering, while building new solar-powered stations is in the more distant future. Early involvement in this work by Texas Electric Service Company will provide vital experience as this anticipated development occurs.

ACKNOWLEDGMENT

The author wishes to express his appreciation to Mrs. Patricia Robinson for careful review and editing and to Mr. George Clary and Mr. Jim Allison for their technical assistance in preparing this paper.

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SOLAR PONDS - WHAT ARE THEY?

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Estes Park, Colorado

ABSTRACT

Solar ponds can provide low cost solar energy collection as well as low temperature heat storage. Currently there are two types of solar ponds in an advanced state of development in the U.S. Each system uses a different collection and energy storage technique. The first system uses a large bag of water (a water bed in a greenhouse) which collects the solar energy during the day. After the sun's energy can no longer be collected the water is transferred to an insulated storage tank for use the next day.

The second system uses a salt gradient within a water filled pond. The gradient prevents natural convective currents from dissipating the collected energy. The gradient pond has a solar heated layer within the pond. In this layer, a heat exchanger is installed to retrieve the collected solar energy. A solar pond of this design is providing heated pool water for a municipal pool in Miamisburg, Ohio.

This overview paper reviews the various designs of solar ponds and how they can be used to collect and store solar energy. The performance and cost data available will be presented and discussed.

INTRODUCTION

Industry uses approximately 40 percent of the total energy consumed in this country. The time is fast approaching when industry will be economically (and physically by shutoff) forced to look at alternative methods of providing needed thermal energy.

Solar ponds are well suited for various agricultural and industrial process heat as well as annual storage devices for space heating and cooling.

Most solar thermal systems, such as concentrating collectors or flat plate collectors, have separate collector units and storage units. In the solar pond systems to be discussed, it is difficult to distinguish the collector from the storage. The same body of water serves as both collector and storage.

In a natural pond or lake, a large amount of the sun's energy is absorbed in the mud bottom. This sets up a convective circulation in the pond with warm water rising to the surface, cooling and then sinking back to the bottom of the pond. (Figure 1.) This results in the water temperature remaining below the ambient air temperature.

In 1902 it was first noted that naturally occurring salty lakes had an unusual behavior--the temperature at the bottom of the lake was substantially higher than at the surface. The increased density of water due to dissolved salts prevented the normal convective cooling cycle to be developed.

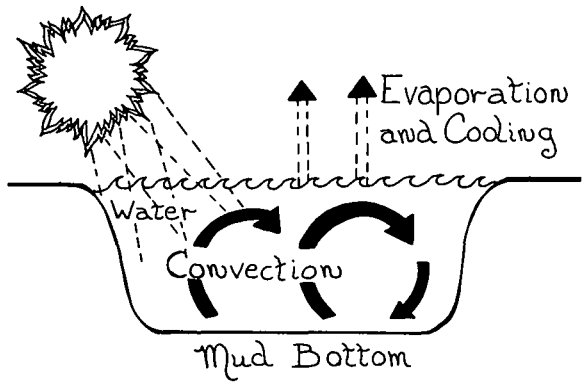


Figure 1. Natural Pond Convection

This is the basic concept behind solar ponds. They are shallow bodies of water, both fresh and salty, whose objective is to capture and store solar thermal energy cheaply. Solar ponds reduce heat loss by preventing convection within the water storage medium or by covering or containing the pond. The solar pond family tree is shown in Figure 2.

One concept of the non-convecting pond uses a salt gradient (like the natural salty lake) to prevent the convectional loss of heat. This system is operational. Another concept that is being researched is the use of membranes between water layers to prevent heat loss through convection.

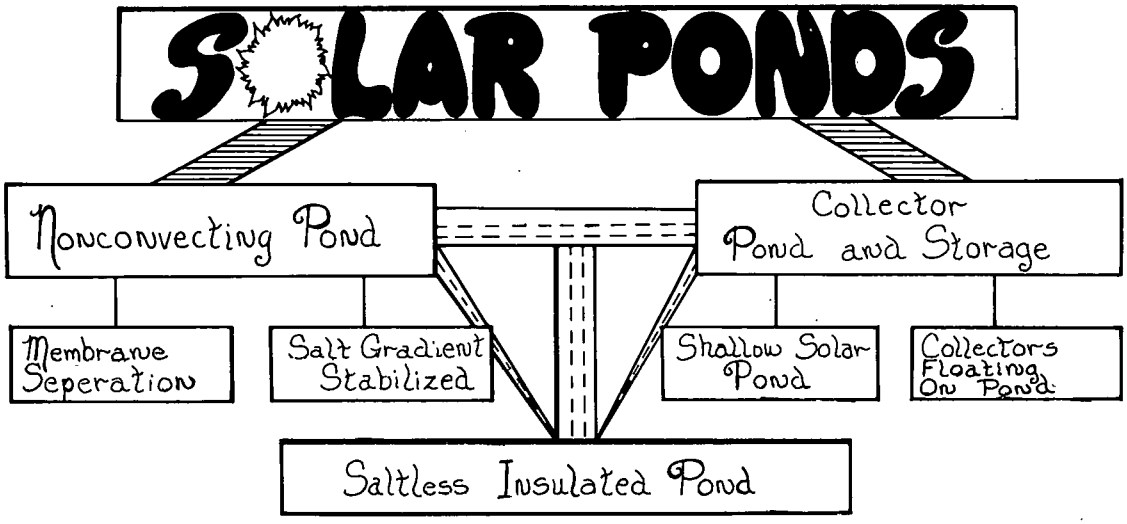


Figure 2. Solar Pond Family Tree

The collector pond/storage concept has two major concepts under development. The Shallow Solar Pond uses fresh water in a waterbag under a glazing (a water bed in a greenhouse) to collect solar energy. The second concept is the use of conventional solar collectors floating on a raft made of insulation atop the fresh water pond. Water is drawn from the pond and circulated through the solar collectors to be heated.

An overlapping concept is the use of deep salt-free ponds combined with nighttime insulation.

A discussion of each type of system is presented as an overview of the state-of-the art. Specific design techniques and information on predicting heat gain can be found in the reading list at the end of the report.

The discussion will start with the shallow fresh water pond, and next the floating collector concept. The salt gradient pond, the membrane stratified pond, and saltless deep pond discussion follows.

SHALLOW SOLAR PONDS

The shallow solar pond is a solar collector that is intended to provide large amounts of heated fresh water at prices competitive to fossil fuel.

Increasing fuel prices and the development of new inexpensive plastic materials that can be used in construction of shallow ponds have made the concept now economically viable.

A typical shallow solar pond module consists of a 16 ft. x 200 ft. (5-m x 60-m) plastic bag filled with fresh water to a depth of 4 inches (100 mm). The bag rests on a layer of insulation and is covered with a fiberglass glazing as shown in Figure 3.

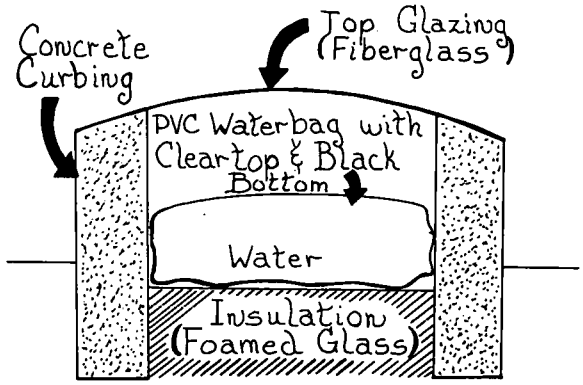


Figure 3. Shallow Solar Pond

The shallow solar pond is designed to be used as a batch system. Water is heated during the day. Later, at sunset (or during a period of overcast), the warmed water is drained to an insulated storage tank for use during the new work period. The next morning the process starts all over with the filling of the bags with low temperature water (50-60 F). In climates where the nighttime temperature is higher than the inlet water temperature, the bags can be filled at night to preheat the water for the next day.

A flow through mode can be used if the water only needs to be heated a small amount, such as 10 or 20 degrees F. Cold water is piped in at one end of the pond, allowed to flow through the water bag and

is withdrawn, warmed, at the other. Water depth is controlled by the flow rate and dams built into the water bag or pond.

Each component of the system will be briefly described.

The water bag is made of two layers of plastic film, usually ultra violet (UV)-stabilized polyvinylchloride (PVC) film sealed along the edges. The bottom layer is 20 mil thick and is black in color to absorb the solar radiation, while the top layer is 12 mil thick and is clear. Small valved vents are included in the top of the bag to eliminate air pockets if necessary. Normal small bubbles formed during the day-to-day operation are not a problem. The valves are used if a system malfunction allows a large air pocket to form.

PVC bats are suited for industrial use at 150°F (65°C) or less. Because of health hazards, they cannot be used for the direct heating of potable water. If it is necessary to heat potable water, a heat exchanger can be used or a plastic material that is approved for use with potable water such as polybutylene, chlorosulfanated polyethelene (CSPE) and chlorinated polyethelene can be used. Polybutylene, which is used for foods that are to be cooked in their own wrappers, is cheaper than PVC or CSPE, but it is very susceptible to ultra violet rays and will have to be replaced every 4 to 5 years.

Over the plastic bag is the glazing surface made of corrugated greenhouse fiberglass. The glazing serves as an air container to reduce convection and radiation heat losses from the top surface of the bag. A layer of hot air prevents air currents which would cool the bag. If low water temperatures are needed, less than 125 F, it would be better to eliminate the glazing.

Though this will reduce capital investment it will not save money, because bag life will be shortened by exposure to the weather, dust, and ultra violet radiation.

If higher temperatures (above 180 F) are needed from the pond, the addition of a second glazing just above the first glazing is necessary. This however, reduces thermal efficiency by reducing the amount of sunlight that can reach the pond and increases the cost of the pond.

If a shallow solar pond is built directly on the ground, bottom heat losses can amount to 20% of the daily collected heat, assuming the ground is completely dry. However, if the ground is damp--bottom heat losses will be considerably higher. Foamed glass insulation 1½ inches thick is recommended. The material is impermeable to water. With insulation the heat losses are calculated to be about 6% of daily collected heat. Polyurethane foam was tried at a New Mexico site, but in a dry pond condition (water removed from the bag) the large temperature gradient across the foam slab caused severe buckling of the material.

The sides of the pond or curbing, is built to standard concrete construction specifications. A slope of 1:1200 is used along the length of the pond to insure drainage and a 1:100 slope is used across the pond towards the center.

The standard shallow pond module (16 ft. x 200 ft.) can heat 8000 gallons (30,000 liters) of water from 60 F (15 C) to a temperature of 140 F during one day under ideal summer conditions as found in the southwest.

Shallow pond costs are less than conventional solar collector systems. Using 1977 prices, a 1-acre collection area--that is 20 modules--costs about four dollars per square foot ($40 per square meter) for the collector system. The auxiliary water storage and distribution systems adds another $1 to $5 per square foot ($10 to $50 per square meter), depending upon the location.

When evaluating shallow solar ponds, there are two considerations that must be kept in mind.

The first major consideration is available land. For example, a plant that uses 48 million Btu per day will need at least one acre of land on which to locate the ponds to supply 50% of the annual heat load. This area has to be free of shadows from trees, buildings, smoke and steam plumes. If placed on a roof of a building, the building must be strong, capable of supporting more than 20 pounds per square foot.

The second (or maybe the first) limitation is economics. The general rule is that shallow ponds are not a viable investment when competing with energy sources that are available at less than $2 per million Btu.

While these do limit the application, there are still a large number of locations in this country where solar ponds could be used.

A shallow pond system should require little maintenance during the first few years of life.

Depending on materials used, it may be necessary to replace the water bags as often as every 3 to 5 years; however, some materials will have a 10-year life. The glazing will require replacement every 10 to 20 years. The rest of the facility will require normal operation and maintenance expense for a water distribution system. (1)

The ideal use of shallow solar pond water are those that can use the water directly. Such applications include domestic hot water for large residential users, industrial wash water, or feed water for boilers. Shallow ponds, used with heat exchangers and low boiling point fluids such as Freon, can be used to drive turbines to produce electricity.

The heated water can also provide the low grade heat needed to drive an industrial size heat pump. The heat pump can then operate at a co-efficient of performance (COP) much higher than one using ambient air or water as a heat source.

A large shallow pond will be installed this summer at Ft. Benning, Georgia. The 275,000 square foot installation will heat 500,000 gallons of water per day for the domestic water needs of the base. The cost is expected to be $3.75 per square foot for the collectors, plus an additional $5.25 for the plumbing and auxiliary equipment. (2)

FLOATING COLLECTOR

The collector floating on a pond concept is best demonstrated by work being performed by a Swedish group, now being built at the Studsvik R&D Centre.(3) Parallel work was performed at the Solar Energy Research Facility, University of Arizona. (4). A bank of tilted concentrating collectors is fixed on a raft of insulation floating on top of a large deep pond as shown in Figure 4. This concept was designed primarily for district home heating using a hot water distribution system to each home. The unit will collect heat energy all summer long, store it in the deep pond and have it available for use during the winter months.

Construction is fairly simple. A pit is dug and lined with a temperature resistant rubber or plastic, sealing against the leaking of the heated water. During the summer storage charging period, water is taken from the bottom of the storage pit, heated in the solar collectors and discharged just below the surface of the water. The pit is not insulated, for after a year of operation the surrounding ground is

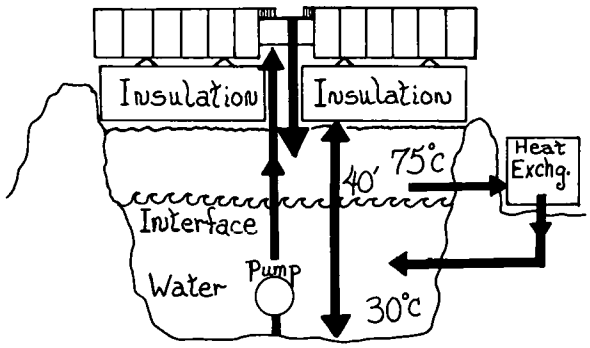


Figure 4. Floating Collector Concept

now heated and acts as a natural insulator.

Since the storage pit is circular, the floating lid can be rotated to follow the sun, allowing maximum heat recovery.

A small prototype collector system was built at the University of Arizona to test the concept. The collector covered a 16 x 16 ft. area and had a peak production of about 45,000 Btu per hour.

The square collector floated in the middle of a circular pond. Parabolic troughs, having a 5X sun concentration were used. Maximum energy production can be as high as 185 Btu per square foot of collector per hour.

Azimuth sun tracking using floating platforms appears to be cost effective. The use of fixed parabolar or an aximuth tracking platform has potential for large, high temperature systems.

The cost per home of a floating collector system to provide district heating, based on a 248 home subdivision (3 homes per acre), ranges from $4200 to $6200. This is substantially lower than individual solar units on a home. This concept is applicable to industrial process heat. (4)

SALT GRADIENT PONDS

The salt gradient pond is simultaneously a collector of solar energy and a large thermal storage body.

The salt gradient pond has massive thermal storage and heat loss takes a period of time even in the absence of sunlight. Thus, the salt gradient pond can convert an intermittent energy source--solar radiation--into a reliable source.

The efficiency of conversion from the solar radiation to thermal energy ranges from about 10% to

30% depending on pond location and output temperature. Although conversion efficiency is low, cost and complexity are also low.

The salt gradient solar pond has been thoroughly researched and a working system has been installed. The salt gradient pond contains three layers (Figure 5): the surface layer--a thin layer of nearly saltless water in which there are vertical convection currents due to wind and evaporation; the non-convecting layer--a layer in which an increasing concentration of salt is found which prevents vertical convection; and the lower convecting layer--a storage layer in which the salt concentration is constant. The

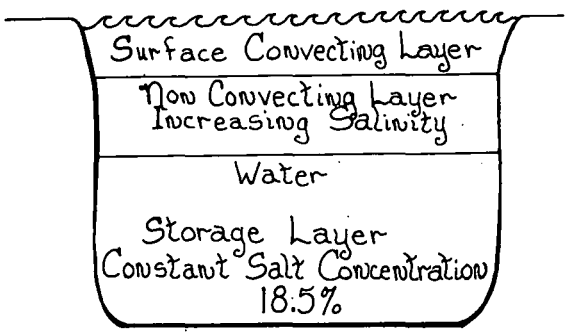


Figure 5. Salt Gradient Pond

non-convecting layer serves to insulate the storage layer, preventing heat loss to the surface. The convection of the surface layer is unavoidable, due to the effects of wind and evaporation. The bottom of the pond is usually lined with a blackened plastic film to prevent water leakage and to absorb the sun's energy that reaches the bottom of the pond. Heat removal for work takes place in the storage layer, either through a heat exchanger placed in the storage layer or by the direct transfer of the storage layer liquid to a heat exchanger located at the point of use. (5)

The salt pond can best be illustrated by a description of a pond now in operation. (6)

The largest working salt gradient solar pond in the U.S. was constructed by the city of Miamisburg, Ohio as part of its Community Park Development Project. The pond is used to heat a 50 meter outdoor swimming pool (650,000 gallons) in the summer and meeting rooms and office space during the winter.

The salt gradient pond is 180 ft. by 120 ft. (55.4-m x 36.9-m), having a surface area of 21,000 square feet (2020 square m). The pond holds 1,400,000 gallons of water.

The sides of the pond taper at an angle of 45 degrees to a depth of 10 feet (approximately 3 m). The pond is lined with a chemically resistant polymer coated polyester fabric "Petrochem" 0.7 mm thick. The material was tested in outdoor exposure tests to 240 F (117 C) and should last more than 10 years. The fabric was heat welded in place during installation.

The pond was then filled with water to a depth of 5 feet (1.5 m). Truck loads of sodium chloride salt were then added for a total of 1,100 tons. When all the salt was added additional water was added to make the water depth 7 feet (2.1 m). The average salt concentration was approximately 14% but there were large amounts of undissolved salt on the bottom. To dissolve the last portion of the salt, a large volume circulating pump was used to mix the pond water and salt. This process required nearly 4 weeks, and the final salt concentration of 18.5% was reached. Copper sulfate was added to the water to control algae growth. Fresh water was then added to the top of the pond.

The final profile consisted of a 15-20 inch fresh water layer, a 40-45 inch layer of a salt gradient ranging from zero concentration at the top to 18.5% at the bottom and then a 5 foot section having an 18.5% salt concentration.

The three layer structure of the pond can be seen in the temperature-depth profile of the pond, shown in Figure 6. The top convection layer nearly

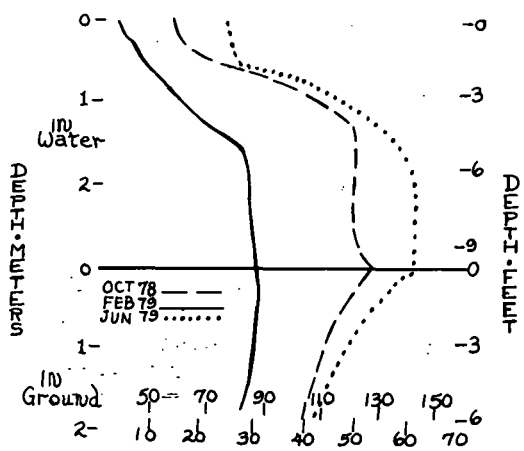


Figure 6. Temperature Profile in Salt Gradient Pond.

disappeared when the pond was covered with ice during February. (With 8 inches of ice on the surface, the

bottom temperature stabilized at 85 to 90 F.)

Two heat exchangers were placed in the pond at a depth of 5 feet and 6 feet. The total areas of the heat exchangers was 1484 square feet (138 square meters).

The total cost of the installed pond was $70,000 or $3.24 a square foot ($35/square meter). The pond, completed in August 1978, reached operational temperature in June 1979. The heat extracted during the summer months of 1979 are shown in the following table.

HEAT EXTRACTION DURING SUMMER SEASON 1978

Period	Heat Extraction Btu (Million)	kW Hr.
June 26-30	24	7.030
July 1-31	66	19.340
Aug. 1-31	43.4	12.720
Sept. 1-5	3	880
Total	136.4	39.970

Based on a DOE evaluation over the expected 10 year life of the system, it is predicted that 381,000 kW hr/year of heat can be extracted and the cost of that heat is 1.8¢/kW hr. ($5.40/million Btu), which is competitive with fuel oil.

In the two heating seasons the pond has been in operation, there have been two major problems affecting performance.

In the first year the heat exchanger had to be removed from the pond and re-soldered with silver solder. The high bottom region temperature of 158 F caused the joints to leak.

During the second year a slow leak developed in the liner. This resulted in decrease in salt concentration from the 18.5% to about 10%, causing a decrease in performance. This leak was repaired by sending a scuba diver down to search for the leak after the pond had cooled to 120 F.

The cost of salts for a solar pond represent a sizeable fraction of the total initial investment. A typical solar pond may require 30% to 60% of the initial investment for the salt. If low cost alternative salts can be found, they could reduce the investment.

A suitable salt must meet several criteria:

- It must be adequately soluble (with a solubility that increases with temperature);
- Its solution must be adequately transparent to solar radiation;
- It must be widely available so that transportation costs do not offset its low purchase costs (or must be available locally at a low cost); and
- It must be environmentally benign.

This is an area where further work can lead to cheaper heat production.

Another application of a salt gradient pond is for the generation of electricity as was shown in the recent test in Israel. At Ein Bokek near the southern shore of the Dead Sea, a 70,000 sq ft rubber-lined pond (7000 sq. meters) 8 feet deep (2.5 meters) has a storage temperature of 176 F (80 C).

To produce electricity, hot brine from the bottom of the pond is used in conjunction with a heat exchanger to boil a low boiling point organic working fluid. The pressurized vapor produced is then used to power a turbine which drives a generator.

To complete the cycle the vapor passes through another heat exchanger where it is cooled (by the water from the top of the pond) and it returns to a liquid state. The fluid then is heated again to run the turbines. The pond can run a 150 kilowatt pilot plant. A large scale plant with a one square kilometer pond (247.1 acres), which could operate a five megawatt power plant, will be built within two to three years in the same area. The cost for a large scale unit is estimated at $2,000 per kilowatt.

This initial success of the Israeli program has led Southern California Edison to plan a five megawatt demonstration plant near the Salton Sea in California's Imperial Valley.

Solar pond boosters say the new technology could eventually meet as much as 12% of U.S. Energy needs and even more in Third World countries. (7)

MEMBRANE SOLAR POND

Another solar pond concept uses transparent membranes to set up a non-convecting insulating layer at the surface of the water. The distance between adjacent membranes is small enough that sufficient friction exists between the relatively fixed membrane surface and the fluid to completely suppress convection. (Fig. 7).

Pressure differences arising in this configuration can be relieved by spacing small holes in the membranes. The holes would allow water to flow under

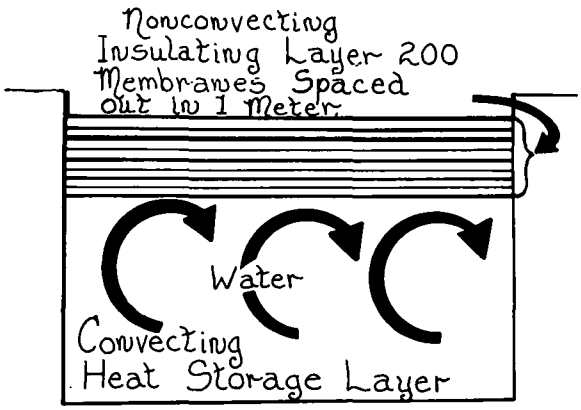


Figure 7. Membrane Solar Pond

small pressure differentials but they would not be big enough to allow convection to take place.

In the configuration shown it is necessary to match the index of refraction of the liquid to that of the membranes in order to minimize reflection losses at the many membrane/liquid interfaces.

If water is used as the membrane liquid, Teflon could be used as the film, for the indicies of refraction for water and teflon are very close. Teflon is a long-lived, inert material and is available in film thickness of 1/2 mil. Ethanol can also be used as the membrane fluid. Since ethanol has a lower thermal conductivity, the membrane layer can be thinner. The higher ethanol transparency will allow more energy to reach the storage layer.

In theoretical evaluations the thermal performance of the membrane pond is very similar to a salt gradient solar pond. Assuming the transmission through the insulating layer of a membrane pond is 35%, the thermal efficiency of the pond for low temperature applications is estimated at 30%.

No large scale unit to test this concept has been built to date. (8)

THE SALTLESS SOLAR POND

The saltless solar pond is a new idea, but as yet untried. Because the saltless solar pond has no non-conductive layer to insulate it from local atmospheric conditions, it must have a glazing over the top of the pond. Since the water is not transferred to storage at night, it must have insulation placed over the pond at night and during periods of low solar energy. The saltless pond loses more heat than a salt gradient pond, but because of the transmission characteristics of the glazing, the pond water will receive more solar energy, (i.e., there are no losses at water interfaces). The net effect is that a saltless pond is more sensitive to fluctuations in ambient temperature and insolation. To control these fluctuations a saltless pond must be made deeper, having a larger mass of water. Various insulation techniques have been proposed, ranging from lids to cover the ponds to a manually spread floating insulation material. One promising technique is the use of liquid foam insulation. This material which has been used in greenhouses, could be sprayed on the surface of the pond at night and allowed to collapse and run off in the morning. In greenhouse tests, it has been found to reduce the heat loss by at least 50% and in theory an 85% reduction is possible. A diagram of the proposed system is shown in Figure 8.

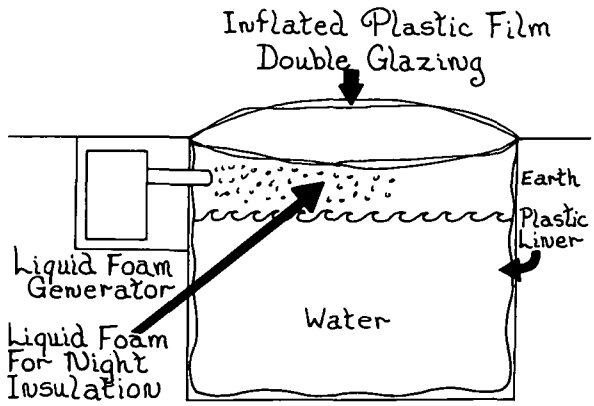


Figure 8. Saltless Solar Pond

An economic comparison between a salt and saltless pond based on computer simulation was performed by the Solar Energy Research Institute. It showed that if the salt used in the pond costs more than $14.90 per ton, then a saltless pond is more economical.

In addition, the saltless pond poses no environmental hazard whereas the salt pond runoff may be environmentally unacceptable. (9).

CONCLUSION

Various methods of collection and heating water using the solar pond concept has been presented. To find a method most applicable to your particular hot water need, it is suggested all techniques should be evaluated. A reading list for further information is included.

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SOLAR ENERGY FOR CHARGING FORK-TRUCK BATTERIES

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ABSTRACT

The demand for renewable energy sources has stimulated technological advances in solar cell development. Initially, development and fabrication were extremely costly and no encouragement for use in industrial applications was made. Today, evidence exists that new technological advances and mass-production techniques have lowered the costs considerably. The U.S. Department of Energy has indicated that by the year 1990 the price per peak watt would be less than fifty U.S. cents.

This paper keeps this price decrease in mind and does an economic study on the feasibility of using photovoltaic cells to charge electric fork lift trucks, at different costs per peak watt. This particular idea could be used as a measure of energy conservation for industrial material handling. Two evaluation methods were used; namely, the Payback Method, and the Modified Energy Inflation Rate Method. Neither of the methods proved to be economically favorable, but some interesting results were obtained.

INTRODUCTION

With energy costs rising all over the world today, industry has had to screen their energy consumption more closely. There are many conservation opportunities available to industry to reduce their operating costs. One such area is that of renewable energy sources, namely solar energy for industrial applications.

This paper attempts to show how solar energy can be used to charge a fork truck battery and to determine whether or not it is cost effective. Some background information is presented on the characteristics and operation of photovoltaic cells. A typical industrial problem is developed as realistically as possible as to costs and work load requirements. Two separate economic studies are then performed to determine the feasibility of the proposal. The idea behind this paper is that the energy and technology is available to perform as proposed, but that the underlying factors of economics are not yet cost effective.

PHOTOVOLTAIC DEVICES

Photovoltaic cells or solar cells are thin films or wafers of semi-conductor material that convert from 3 percent to somewhat under 30 percent of incident solar energy into DC electricity. The efficiency of this conversion depends on the illumination-spectrum intensity, solar-cell design and materials, and temperature. A solar cell behaves very much like a low-voltage battery, whose charge is replenished by the incident illumination. Connecting the cells into a series-parallel configuration allows the solar "panels" to yield high currents and voltages. This type of system can be combined with energy-storage and power-conditioning equipment to form a complete solar electric conversion system. These devices have been advancing rapidly since 1955, and are used extensively in NASA projects.

The system has a number of advantages; namely,

1. No moving parts
2. Very low degradation of properly sealed cells.
3. Can be grouped into modular systems at sizes from a few watts to megawatts, and
4. Extremely simple to use.

The high costs of development and fabrication have discouraged any thought of widespread use in industry. There is good evidence today that new technological developments and mass-production techniques have lowered the costs substantially. Research is being conducted to further reduce the cost of photovoltaic systems to a point where it will be economically competitive with other electric power

generation schemes. The United States Department of Energy (USDOE) has indicated that these goals will be attained, and that the price would be less than fifty U.S. cents per peak watt by 1990.(3)A plot showing the rate of decrease in cost of photovoltaic devices, as predicted by DOE, is well on its way to meeting the desired goals. These predicted goals are indicated by horizontal lines in Figure 1.(1) Some of the latest developments include the continuous production of ribbon silicon, efficiency and stability improvement of CdS solar cells, and the development of inexpensive, wide-aperture concentrators (Winston Collector).(4) There are numerous articles printed that bear witness to this new frontier of technology.

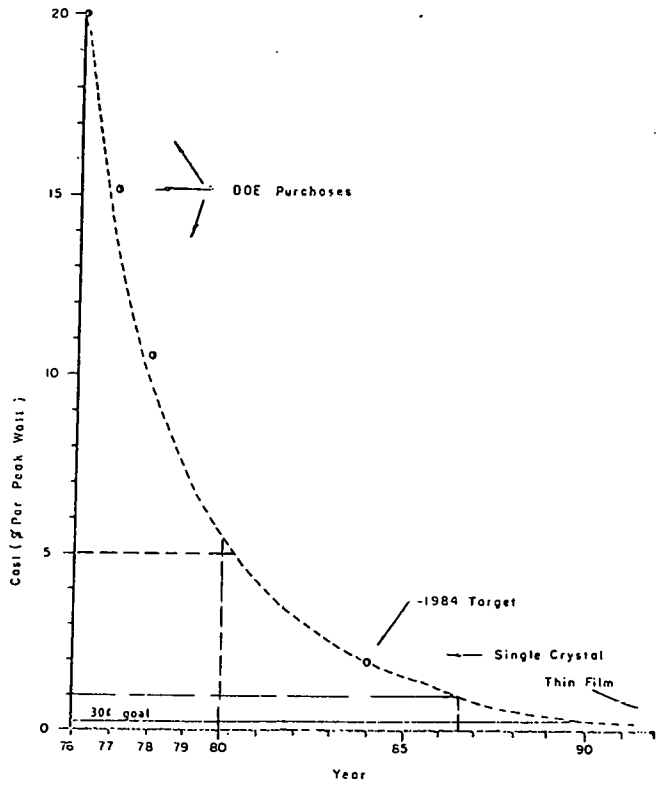


FIGURE 1 Projected Solar Cell Prices and some Recent Purchases

Principle of Operation

The operation is based on the photovoltaic effect: creating charge carriers within a semiconductor material using sunlight as the incident ionizing radiation. The solar cell consists of several basic elements listed below:

1. A base material for one side of the junction
2. A diffused or deposited region that forms the other side
3. An anti-reflection coating to boost efficiency
4. Front and back contact grids to reduce series resistance
5. A transparent adhesive and cover glass to enhance environmental stability of the cell. See Figure 2.(6)

Energy conversion is initiated when a photon of sufficient energy penetrates the cell and dislodges an electron in the p-type region from its chemical bond, thereby giving it enough energy to move freely about the material. The vacant electron position (or hole) is said to "move" if an electron from a neighboring bond exchanges places with it. The holes move in a direction opposite to that of the electrons. The holes are designated by positive charges and the electrons by a negative charge.

A current is created if the pairs of electrons and holes are separated by an intrinsic voltage in the cell material. The electrons (-) move toward the n-type region, and the holes (+) move toward the p-type region (lower contact). An external circuit allows the electrons to flow in a continuous loop to recombine with the holes near the p-type contact. The creation and control of this intrinsic voltage has made semiconductor electricity a reality. One of the most frequently used techniques in manipulating this voltage is the use of an abrupt discontinuity in the

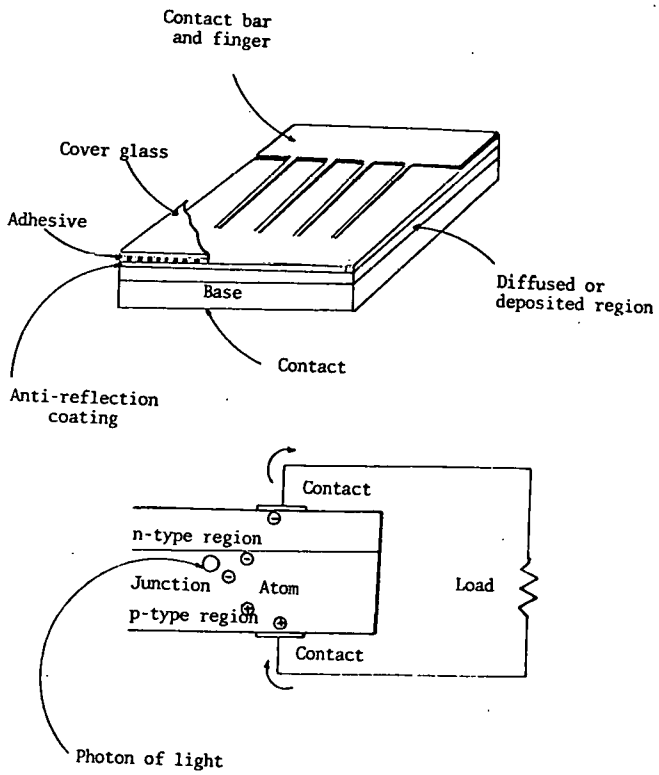


Figure 2. Photovoltaic Cell Description

in the conductivity of the base material by doping (addition of impurities to the pure material), called homojunction. Other methods are also used but they ll not be discussed here. The main limitation to photovoltaic conversion efficiency is that some photons lack the energy to initiate this process, while others have more energy than is needed. (6, P. 85)

EXAMPLE PROBLEM FORMULATION

A typical fork lift truck has to perform according to the following requirements each day:

Fork Truck Type: EC 300-530 36/40 volt
Fork Truck Capacity: 4000 lb.
Fork Truck Weight: 6800 lb.
Load Frequency: 8 times/hour
Travel Distance: 300 ft. (one way)
Average Lift Height: 8 ft.
Ramp Rise: 5 ft.

The duty cycle can be estimated from the accompanying Figures 3, 4, and 5. (5) Formulae are available to calculate the battery capacity requirements, but the charts provide a more convenient method. The following data must be determined in order to use the charts

1. Weight of the truck
2. Average weight of loads handled
3. Average length of one-way trip (ft.) including ramps
4. Elevation of ramps in feet
5. Number of trips desired per hour
6. Average lifting height
7. Number of lifts per hour
8. Conditions which require frequent acceleration

The fork truck Travel Current (TC) is determined from Figure 4, by entering the chart on the left and reading the watt hours on the base of the chart corresponding to the respective distance of one-way travel. This same procedure is carried out for the return trip with the unloaded truck. The sum of the two currents give the total travel current for the round trip. The chart does include an allowance for current required to accelerate. Total travel current for this problem is 53 + 33 = 86 watt hours assuming that the truck accelerates once per trip.

The fork truck Lift and Tilt Current (LTC) is determined from Figure 5. Lifting a 4000 lb. load eight feet requires 33 watt hours/lift. Similarly, the Ramp Current (RC) is specified to be 34 watt hours rip from Figure 3. A total of 153 watt hours is required to complete one trip. If the truck is to make 8 trips/hour or 64 trips per eight hour day, a total

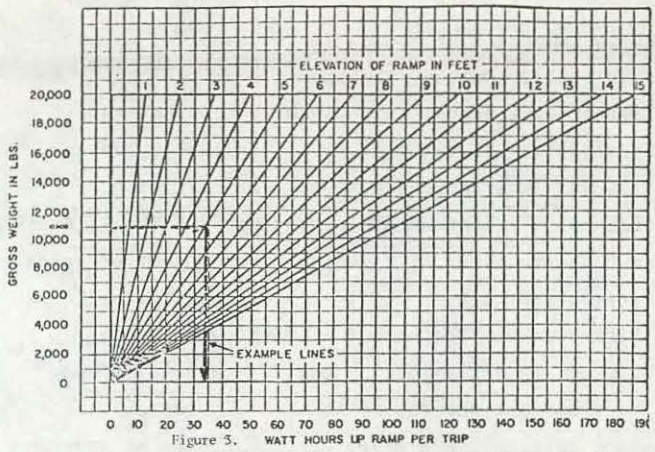


Figure 3. WATT HOURS UP RAMP PER TRIP

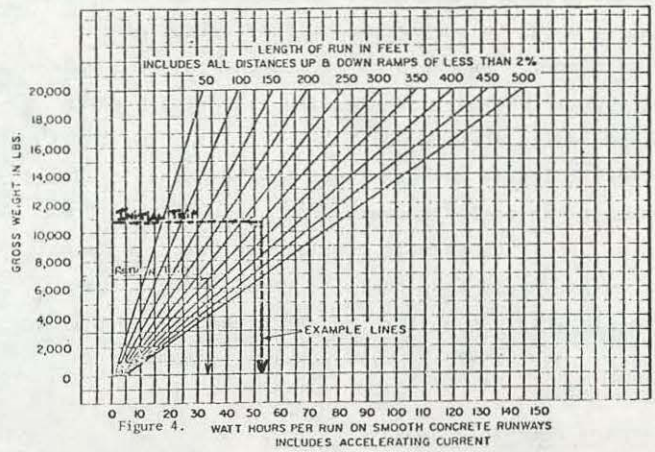


Figure 4. WATT HOURS PER RUN ON SMOOTH CONCRETE RUNWAYS
INCLUDES ACCELERATING CURRENT

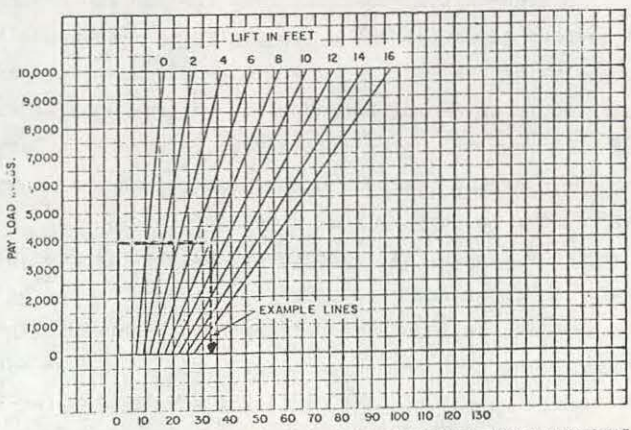


Figure 5. AVERAGE WATT HOURS PER LIFT INCLUDING CURRENT FOR 10° BACK & FORWARD TILT

of 9792 watt hours/day are required. (9.792 KWH/day). A 25% factor of safety is added to give the minimum battery size requirement of 12.24 KWH/day.

Battery Ratings

It is important that a battery be sized correctly according to the demands of the operating period. Every battery cell has what is commonly known as an Ampere Hour capacity Rating (AHR). These ratings are usually based on a six hour period and merely refer to

the amount of amperes at which a battery will discharge for six hours. It is important to remember that the ampere hour rating is the same for any number of cells, and that the ampere hour rating of the cell increases proportionately with the numbers of plates/cell. For example, an 11 plate cell has an AHR of 425, whereas the same type of cell with 21 plates has a rating of 850 ampere hours. The Kilowatt Hour capacity (KWH) of a battery is the only practical and useable rating to consider when applying batteries to lift trucks. The amount of work performed by a lift truck is determined by the KWH capacity of the battery and not the AHR of the cell. Generally, the average voltage of a given battery should be approximately equal to the normal voltage rating of the drive motor. Lead-acid batteries have about 2 volts/cell, while nickel-iron-alkaline batteries have an average voltage rating of 1.2 volt/cell. The total battery voltage, as determined by the number of cells connected in series, governs the speed of the fork truck. For this example problem the batteries are to be charged every four hours to ensure a full charge. A local battery supplier indicated that Allis-Chalmers battery model 18-75-21 will supply the demands adequately.

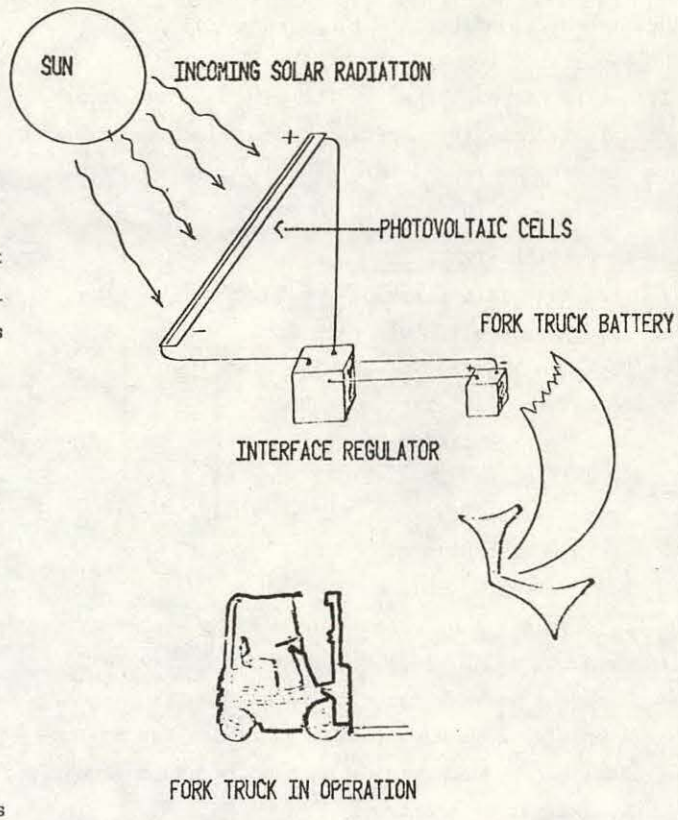


Figure 6. Diagramatic System Layout

Charging Lead-Acid Storage Batteries

A high initial charging rate (25 amp/100 amp-hr. of battery capacity) and a low finishing rate equal to about 20% of the initial rate are required for proper charging in an 8-hour period. The voltage applied to the cell must be approximately 2.63 volts/cell. During the charging period the charging rate tapers downward as the battery voltage rises and "bucks" the charging voltage. (5) With these characteristics in mind, an "interface regulator" is needed between the photovoltaic cell and the battery being charged. The reason being that the photovoltaic cell is a constant DC source supplier. The regulator should also terminate the charging process once it is complete so as to avoid back discharge. This automatic termination is accomplished either with a fixed or variable time-cycle for the charge. The Oklahoma City supplier quoted the battery and the interface regulator to be approximately $5300. A diagramatic system layout is shown in Figure 6.

SYSTEM REQUIREMENTS

The charge/discharge efficiency of a battery is approximately 80%. Taking this into account increases the fork truck battery capacity to 15.3 KWH/day.

ie., $$\frac{12.24 \text{ KWH/DAY}}{.80} = 15.3 \text{ KWH/DAY}$$

1. Known parameters

   Battery capacity requirements: 15.3 KWH/DAY

   Solar cell cost : $5/PEAK WATT*

   1 Peak Watt supplies = 5 Watt Hours/Day

   500 Watt Hours/(m^2/day) is typical

2. Costs

   $$\text{Solar Cell} = \frac{15300 \text{ watt hour/day}}{500 \text{ watt hour/m}^2\text{/day}} = 30.6 \text{ m}^2$$

   $$\text{Solar Cell Cost} \cong \left[15300 \text{ watt hour/day}\right] \left[\frac{\$5/\text{Peak watt}}{5(\text{watt hour/day})/\text{Peak watt}}\right]$$

   $$= \$15300$$

The total cost of a "photovoltaic" regulator charging system consists of the following major elements:

1.	Solar cell cost (sized**) ...	$15,300
2.	Interface regulator cost. . .	1,000
3.	Single battery cost (extra)..	4,300
4.	Freight & Installation	2,000
		Fixed cost $7300

* Present price as specified by the D.O.E. projection

**Based on $5/peak watt.

Total Installed Cost (Investment).....$22,600

5. Maintenance/year 200

3. Savings

The solar cells will relieve 12.24 KWH per day from the plant's daily electricity demand. This assumption also takes into account the average savings that will result due to power factor and demand charges.

According to the statistics released by Energy User News* electricity costs have varied from $0.03/KWH to $0.45/KWH to date. Attractive government and state tax credits make solar equipment more desirable. Presently, the government allows for a 20% total tax credit (10% energy credit + 10% equipment credit) on solar energy equipment used in production.

There were two other bills in Congress calling for a 30 or 40% tax credit to be allowed, but these have been bogged down. Some states do provide additional credits to help potential investors. California is one such state that allows a very substantial credit. The potential of these tax credits will become evident in the economic analysis of this paper.

ECONOMIC ANALYSIS

Payback Method

The initial approach for evaluating the feasibility of the solar cell system is to determine the undiscounted payback period. Table I summarizes the overall results of the calculation procedure presented below:

- Column A.

  Proposed Solar Cost/Peak Watt = $X/Peak Watt

  - where X = 5, 4, 3, 2, 1, .50, .30

- Column B.

  $$\left\{\begin{matrix}\text{Installed Cost for}\\ \text{12.24 KWH/Day}\end{matrix}\right\} - \left\{\begin{matrix}\text{Single Cell Cost}\\ \text{for 12.24 KWH/Day}\end{matrix}\right\} + \left\{\text{Fixed costs}\right\}$$

  Solar Cell Cost = [15300 Watt Hour/Day] * [$X/Peak Watt / $5(Watt Hour/Day)/Peak Watt]

  - where X = 5, 4, 3, 2, 1, .50, .30

  Fixed Costs = $7300.

- Column C.

  [Column B] - .20 [Column B] = $ _____ net cost after tax credit.

- Column D.

  Energy Savings of $Y/Year at $0.0X/KWH = [12.24 KWH/Day] [$.0X/KWH] [255 Days/Year]

  -where X = 3, 45, 6, 7

- Column E.

  Total Installed Cost (Investment)

- Column F.

  Undiscounted Payback = Column E/Column D = Years

A Proposed Solar Cell Cost $X/Peak Watt	B Installed Cost for 12.24 KWH/Day $	C Less 20% Tax Credit $	D Energy Savings of $Y/Year at $.0X/KWH .03	.045	.06	.07	E Investment Column C $	F Column E ÷ Column D Undiscounted Payback (Years) .03	.045	.06	.07
5	22600	18080	94	141	187	219	18080	192	128	97	83
4	19540	15632	94	141	187	219	15632	166	111	84	71
3	16480	13184	94	141	187	219	13184	140	94	71	60
2	13420	10736	94	141	187	219	10736	114	76	57	49
1*	10300	8288	94	141	187	219	8288	88	59	44	38
.50	8830	7064	94	141	187	219	7064	75	50	38	32
.30	8218	6575	94	141	187	219	6575	70	47	35	30

TABLE I. PAYBACK METHOD CALCULATIONS

*The Modified Inflation Rate Method example uses this data.

* Energy User News, Fairchild Publications, New York N.Y. October ___. 1979, p. 18.

The Payback Method ignores the time value of money, but does allow for a "ball park" analysis. The high investment costs tend to dominate the feasibility of the proposal at all levels of energy cost ($/KWH). As the investment cost decreases and the energy costs increase, better payback periods start to fall out (see Figure 7). It would appear logical to inflate the energy cost and subsequent savings to arrive at a more "concrete" answer. Therefore, a modified energy inflation rate analysis is applied to this example problem and is presented next.

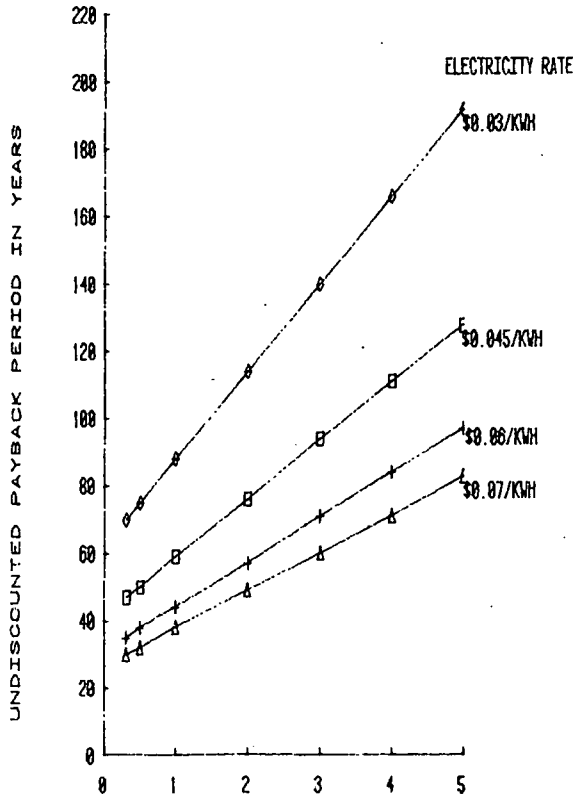


Figure 7. Proposed Solar Cell Cost $X/Peak Watt vs. Undiscounted Payback Period in Years.

Modified Energy Inflation Rate Method

A more sophisticated analysis of evaluating energy proposals has been developed by Dr. Wayne Turner and Dr. Ken Case of Oklahoma State University (7). The method developed by them analyzes the present worth of cash flows with multiple rates of inflation. This method is not discussed in detail here, but the reader is encouraged to pursue the paper referenced. A step by step procedure is given below for the analysis:

1. Determine all component cash flows in "constant worth" dollars, except those for which $k \neq j$.
2. Project those cash flow components for which $k \neq j$, using
   $k' = \frac{1 + k}{1 + j} - 1$
3. Discount to present worth using the interest i.

-where k' = unknown incremental - equivalent energy inflation rate
i = interest rate
j = general inflation rate
k = specific inflation rate for energy (6)

The calculations are simple, but time consuming as shown in Table II. The data below provides the necessary information to complete the table:

Overall installed cost at $1/Pk.Watt	$10360
Energy Tax Credit	$ 2072
Fixed costs	$ 7300
Investment ($10360-$2072)	$ 8288
Maintenance/Year	$ 200
Life (estimated)	7 years
Savings at $0.07/KWH	219/Yr
k = Energy Inflation Rate	20%
j = General Inflation Rate	8%
k' = Modified Energy Inflation Rate	.111111
i = After Tax Interest Rate	5%
$/Peak Watt	1
Depreciation (Salvage = 0)	Sum of Years Digits

The table shows a negative present value of the cash flows. This indicates that the project is not cost effective at the rates considered. It should be noted that this method took advantage of the government tax credit, inflation rates, and accelerated depreciation to arrive at the final conclusion.

SUMMARY

This paper has examined the feasibility of using photovoltaics to charge an industrial fork truck. The example problem developed is designed to allow for as many relevant costs as possible. Two methods are used to evaluate the cost effectiveness of the proposal.

In the payback method the initial cost was decreased by the allowable 20% tax credit, and the yearly energy savings were computed for different electric utility costs ($/KWH). Payback periods were unfavorable, but a definite trend was shown to exist between the electric utility costs and the corresp ing payback. For example, the payback period decreased rapidly as the electric rates increased. This

End of Year	① Investment	② Then Modified Savings at k' = .111111*	③ Constant Worth Maintenance	④ Depreciation SYD**	⑤ ②+③+④ Taxable Income	⑥ Tax 50%	⑦ ②+③+⑥ Then After Tax Cash Flow	⑧ Present Worth After Tax i = 5%
0	-$8288						-$8288	-$8288
1		$243.33	-$200	(-)$2590	-$2546.67	$1273.34	1316.67	1254.00
2		270.37	- 200	(-) 2220	- 2149.63	1074.81	1145.18	1038.68
3		300.41	- 200	(-) 1850	- 1749.59	824.74	925.15	799.14
4		333.79	- 200	(-) 1480	- 1346.21	673.10	806.89	663.83
5		370.88	- 200	(-) 1110	- 939.12	469.06	639.94	501.39
6		412.09	- 200	(-) 740	- 527.91	263.90	475.99	355.18
7		457.87	- 200	(-) 370	- 112.13	56.06	313.93	225.09
				$10,360				-$3450.69

TABLE II. MODIFIED ENERGY INFLATION RATE METHOD

(AFTER TAX CASH FLOW)

* $(\$219)\left[\frac{1+K}{1+j}\right]^n$

** Based on initial cost ($3060 + $7300 = $10,360)

trend can be attributed to the higher savings generated because of the higher electric costs for any one proposed solar cell cost. One might inquire as to how these savings could be discounted under multiple inflationary criteria. This question was addressed under the "Modified Energy Inflation Rate" method.

The second method allowed for both general and energy inflation rates. The actual savings,generated under specific electric utility costs, were discounted using a modified discount rate(k'). Maintenance costs were considered to be constant, but could have also been discounted. The investment was reduced by the allowable 20% tax credit, but the accelerated depreciation schedule was based on the original investment cost. The after tax cash flow yielded a negative present worth, indicating that the project is not cost effective using the given rates.

CONCLUSION

As part of a future study, a sensitivity analysis will be done by varying different combinations of the following parameters:

1) tax credits
2) $/KWH cost and hence corresponding savings
3) installed solar cell cost
4) expected life
5) depreciation method

For example, a tax credit will be selected and deducted from a particular solar cell cost. The corresponding savings generated at a particular cost/KWH will be inflated using the modified energy inflation method. In order to facilitate these multiple runs a computer algorithm will be developed. It is hoped that the most feasible set of parameters will be determined this way.

The most encouraging aspect of this study is that a 50% tax incentive will allow a company to take a total of 50% off the initial investment, use an accelerated depreciation, not show any savings throughout the life of the project, and still break even at the end.

The use of solar cells should not be disregarded because these results were not favorable, but should be considered from time to time as an alternative energy source. Latest reports and writings indicate that DOE will attain their predicted goals of less than 50 U.S. cents.

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CONSERVATION: AN IN-PLANT ENERGY RESOURCE

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ABSTRACT

Potential energy savings of 90 billion cubic feet of natural gas per year on existing facilities in basic steel alone are attainable through retrofitting and improvement in operations. Areas covered include reheat furnaces, soaking pits, cover annealing, and continuous or batch type heat treating. Improvements discussed include skid and support pipe insulation for underfired furnaces, positive and adequate controls, recuperation, and combustion equipment.

Basic steel and related industries have in their hands a substantial energy resource. This is the potential energy savings on existing facilities attainable through retrofitting and improvement in operation. Write-off time is attractive. A few specifics vividly define the extent of this large untapped resource and identify the areas of potential savings.

Our steel industry, under conditions of high production such as the first half of 1979, will heat on the order of 61 million tons of slabs for hot strip mill operations, another 10 million tons related to plate mills, and possibly another 4 million tons of blooms or beam blanks related to structural mills. This totals 75 million tons and on a conservative basis, the monthly average fuel figures range from 2.4 to well in excess of 3.0 MM BTU/ton heated. We will take the low side of 2.4 MM and savings in fuel of 20% is readily available involving write-off times, for the most part, of less than one year. This means a natural gas savings of 500 cu. ft./ton or 37 billion cu. ft. per year.

Soaking pits which must reheat the ingots that are rolled into slabs, blooms or beam blanks as well as blooms for bar, rod and tube mills offer yet another area of savings. These involve about 90 million tons/year with a potential fuel savings of approximately 200,000 BTU/ton. This totals 18 billion cu. ft. of natural gas per year.

The steel industry also has extensive heat treat facilities involving coil annealing furnaces, direct fired car type or batch type heat treat furnaces, continuous roller hearths and walking beams, continuous anneal and galvanizing lines. The fuel consumption on these furnaces may run from as high as 10 MM BTU/ton down to under 1 MM BTU/ton even though these furnaces have low operating temperatures.

Batch type, single or multiple stack, furnaces used for annealing coiled strip may involve around 40 million tons/year. A reduction in gas consumption of approximately 500 cu. ft./ton is available on about half of these furnaces. This projects to a gas savings of 10 billion cu. ft. per year.

A tube mill may have approximately 10 direct fired car type furnaces heating 30 ton charges to a temperature in the range of 1500°F on short cycle anneals, 5 to 30 hours, and average about 4.3 MM BTU/ton. This can be readily reduced by 1.6 MM BTU/ton with an annual gas savings of approximately 100 million cu. ft.

A roll manufacturer may have in his heat treat facility 12 car type furnaces involving long cycle annealing, over 100 hours, and again temperatures in the range of 1500°F. The average

fuel consumption on such cycles is close to 10 MM BTU/ton and this can be reduced by 7.1 MM/ton. This projects to a savings of 185 million cu. ft. of gas per year. There are 5 or 6 large roll facilities.

A plate mill with a continuous roller hearth furnace handling 30 to 45 ton/hour in harden, quench, and draw operations will run in the range of 0.82 MM BTU/ton with potential savings of 540,000 BTU/ton. This projects to approximately 100 million cu. ft. of gas per year on a single roller hearth. There are about 20 of these furnaces.

A tube plant may have one or more 50 ton/hour harden, draw or normalizing furnaces operating at about 1.5 MM BTU/ton. The consumption can be reduced by approximately 640,000 BTU/ton, which projects to 192 million cu. ft. of gas per year savings. There are approximately 20 of these furnaces throughout the industry.

Other batch type heat treating furnaces related to rod, wire, bar and plate, which total well over a hundred car type furnaces, will add another 10 billion cu ft. of gas in potential savings per year. There are other heat treat and anneal facilities such as continuous galvanizing or tin plate annealing lines, atmosphere furnaces, etc., which can give savings of another 5 to 10 billion cu. ft. of gas per year.

We have now identified yearly gas savings of 55 billion cu. ft. on reheat operations and approximately 35 billion cu. ft. on heat treat and anneal operations. Thus, the total readily attainable potential natural gas savings on the processing side of steel is approximately 90 billion cu. ft. per year which is, indeed, a substantial energy resource lying within the mill gates.

The following detailed review of potential savings on reheat furnaces, soaking pits, cover annealers, continuous anneal and galvanizing lines, car type furnaces, continuous roller hearth and walking beam furnaces will clearly demonstrate the extent of the savings as well as support the claim of fast write-off times.

We consider reheat furnaces first since these represent the biggest block of potential savings. Figure I shows a typical 5-zone furnace which serves a modern hot strip mill. This is a pusher type furnace with slabs progressively pushed from the charge end through the main heating zones and finally through the soak zone where it is removed by extractors. This furnace is designed for 300 tons/hour when heating 10" thick slabs x 33' long and you will note the extensive water-cooled pipe structure used to support the slabs as they are pushed through the furnace.

When developing potential savings on reheat furnaces, the study should involve: a computer analysis both from the standpoint of heat transfer and thermal design, insulation practice and effectiveness, furnace control, combustion equipment, as well as recuperator and refractory enclosure effectiveness. In most cases, a 20% reduction in fuel rate is readily attainable and in certain cases furnace deficiencies can be corrected to increase production on furnace limited operations.

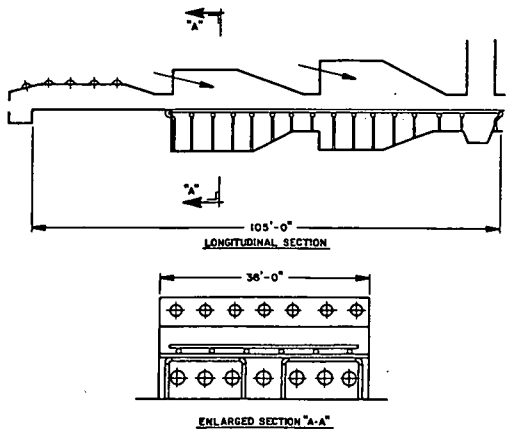
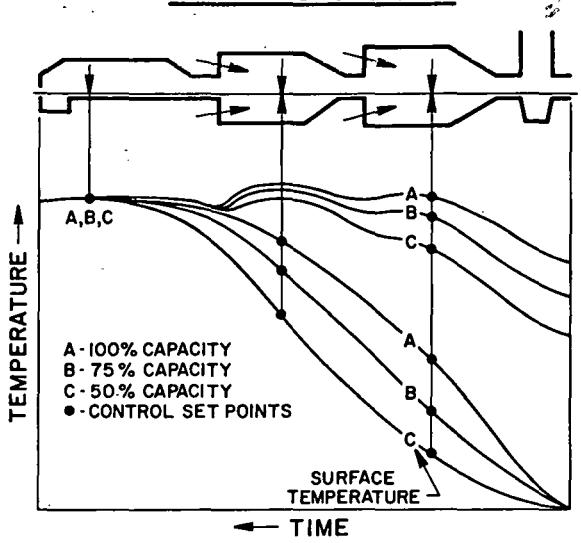


Fig. I - Typical 5-zone furnace capacity 300 ton/hr; slab size is 10" thick x 33' long.

HEATING CURVES



ZONE HEAT BALANCES

% OF ACTUAL REQUIRED INPUT

% CAP.	SOAK	HEAT		PRE-HEAT	
	TOP	TOP	BOTT.	TOP	BOTT.
100	100	40	70	100	100
75	100	70	85	55	75
50	100	100	100	20	40
INSTALL	110	110	110	110	110

Fig. II - Typical computer analysis for 5-zone furnace.

Figure II shows the typical type computer analysis required when evaluating a 5-zone furnace. The computer analysis involves calculating the ideal heating curves for the range of capacity required in day to day operation. It may involve several sets of curves to cover basic differences in the operation such as wide variation of slab thickness or grade. These curves develop the required surface temperature curves for ideal heating practice which define the required temperature set points at control locations for each operation marked A, B, and C on the curves.

The computer analysis also calculates the required input to each control zone of the furnace for each type and level of operation thereby identifying any deficiencies which would limit the heating capability or the ability to operate the furnace most efficiently. The chart at the bottom simply lists the percentage of maximum fuel required for three widely different operating levels. It can be noted that as production decreases, the fuel is shifted heavily towards the discharge end in order to optimize the efficiency.

Figure III illustrates the effect of optimum insulation practice and good furnace control on the monthly average fuel figure of a typical 5-zone hot strip mill furnace.

A prime area of concern is the insulation of the water-cooled support structure. The key to optimum insulation practice is the use of a long life material coupled with the required maintenance practice to assure high average coverage. This certainly suggests the use of a quick attachment type of design to minimize installation time and close attention to maintenance schedules commensurate with production requirements. The center chart shows the effect of increasing the average coverage from 70% with a high heat loss insulation to 85% average coverage with a lower heat loss insulation. The monthly fuel figure drops from 2.4 MM BTU/ton to 2.08 MM BTU/ton on the typical 5-zone furnace serving a modern hot strip, a 13% reduction, generating savings of approximately $1.7 MM per year on a 2.7 million ton per year operation at $2 per million BTU/fuel costs. This is 320 cu. ft. of gas/ton saved or 854 million cu. ft. of gas per year for the operation described.

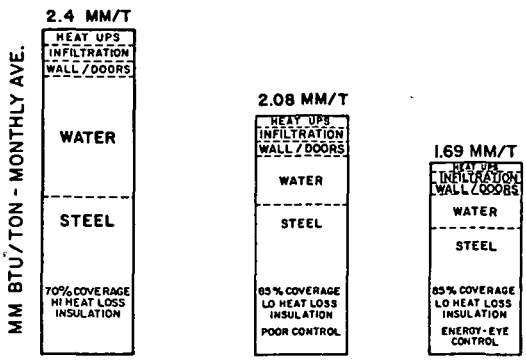


Fig. III - Effect of insulation practice and furnace control on monthly average fuel figure.

Figure III also summarizes the results obtained from correct control practices. Direct steel temperature measurement is by far the best basis for furnace control. It offers tremendous advantage particularly in periods of reduced production or mill delay. The furnace is controlled at the computer defined set points such as A, B, or C from Figure II for each control zone. Positive control of steel temperature as compared to control from furnace temperature, with steel actually uncontrolled, reduces the fuel rate without limiting production and minimizes washing and slagging. Conversely, if control is from furnace temperature, the steel is severely overheated during reduced production or delay periods.

The chart on the right shows the reduction in fuel rate possible through use of direct steel temperature measurement on the typical 5-zone hot strip mill furnace. The right hand chart picks up the operating situation resulting from correct insulation practice, namely, 2.08 MM BTU/ton monthly average. The chart on the right shows the furnace improvement possible through the use of direct steel temperature measurement as furnace control. The monthly average fuel rate is now down to 1.69 MM BTU/ton, a 19% reduction attributable to controlling the steel surface temperature in accordance with actual requirements as compared to the prevalent practice with furnace temperature control of overheating the charge zones at reduced production. The savings are actually 390 cu. ft. of natural gas per ton heated, about one billion cu. ft. per year on the operation defined. This projects to approximately $2.1 MM per year savings based on $2 per million BTU fuel cost and indicates a write-off time of about 1.7 months including all installation costs.

The next potential area of savings is the soaking pit. Figure IV describes the application of adjustable flame burners and temperature difference control to one way fired soaking pits. Soaking pits are equally critical from the standpoint of production and energy consumption. Adjustable flame burners coupled with temperature difference control assures temperature uniformity within the pit, minimum heat time, and reduced fuel rates. The chart shows an actual heat from a pit equipped with such a system and indicates the finish rolling temperatures for each ingot top and bottom. The top to bottom uniformity was 2°F and the end to end uniformity was 12°F.

There are many factors outside of the pit itself affecting both heating rate and fuel consumptions; such as: track times, pit loading pattern, drawing practice, and finish roll temperatures. Substantial increase in heating rates and as much as 20% reduction in fuel rates are possible on many slabbing or blooming operations. The savings are actually about 190 cu. ft. of gas/ton or approximately 300 million cu. ft. per year on a 2 million ton per year operation.

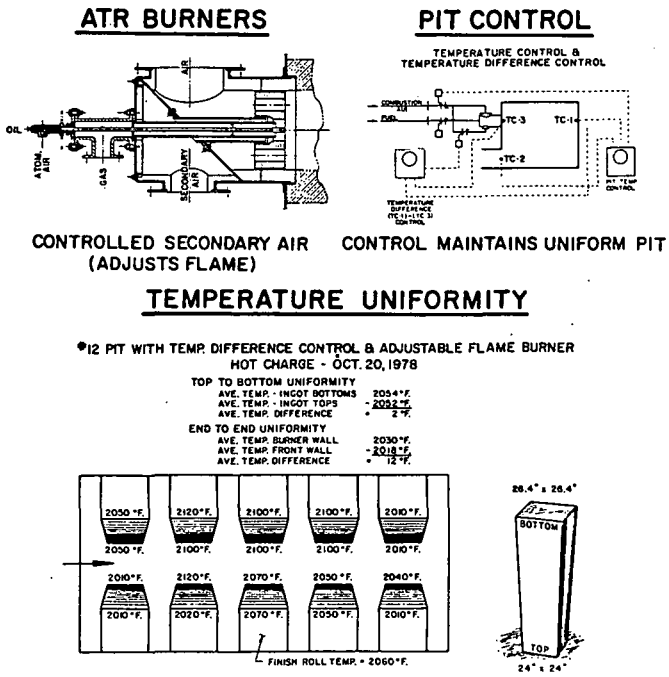


Fig. IV - Adjustable flame burners and temperature difference control for soaking pits.

Cover annealers representing an estimated total yearly savings of 10 billion cu. ft. are interesting in that the input for each furnace is quite low, 3 to 12 MM BTU/hr. However, there are approximately 1200 of these furnaces throughout the industry of which about one half are single stacks, 300 are 4 stack furnaces and the remainder are primarily 8 stack furnaces. Figure V shows a typical single stack cover annealer. These furnaces were originally fired with cold air radiant tube burners. This is an inefficient firing method since the heat is first transferred from a flame to a radiant tube then from the radiant tube to the inner cover. The first step was to convert these furnaces to direct firing and cold air, or at least part of them, and now with the energy crunch to utilize direct firing with hot air. The furnace shown has a flue port near the top of the furnace with a recuperator mounted in it that feeds hot air to a radiant type burner. It is estimated that probably one half of these furnaces are now direct fired but less than half of those utilize preheated combustion air. High production annealing floors may anneal 60,000 to 200,000 tons/month. A conversion from radiant tube firing to direct firing with preheated air gives a 10% increase in production and a 35% energy savings. This means, on a 100,000 ton/month floor, a savings of approximately $1 MM per year based on $2 per million BTU fuel cost or about 400 cu. ft./ton for a total savings for the annealing floor of approximately 500 million cu. ft. of gas per year.

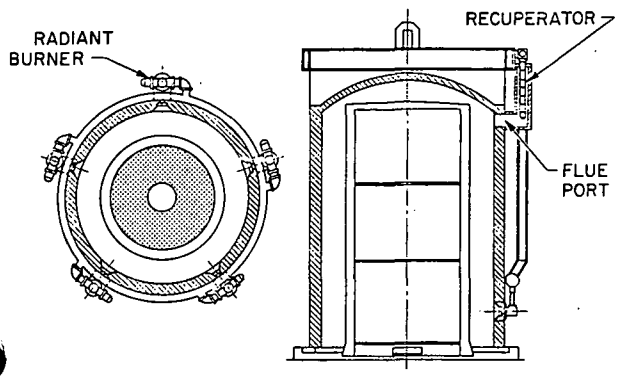


Fig. V - Recuperative direct fired single stack cover annealer.

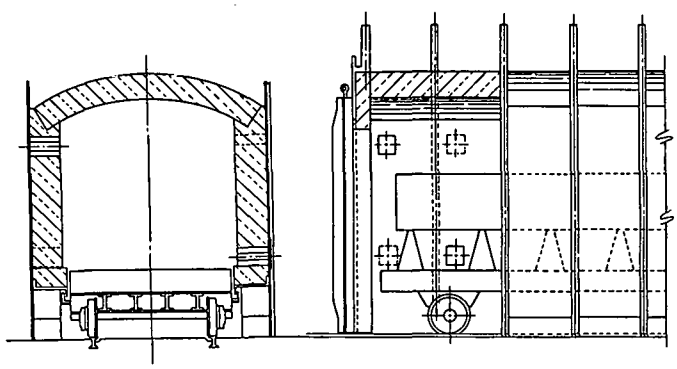


Fig. VI - Typical direct fired car type furnace.

The direct fired car type or batch furnace was pinpointed at the outset as an area of substantial potential savings since there are well over 150 of such furnaces in basic steel and many more in related industries. Figure VI shows a typical direct fired car type furnace with burners mounted in the side walls and firing over and under the charge. The most efficient way to fire this furnace is with stoichiometric fuel/air ratio, that is, the right amount of air for the fuel being burned throughout the cycle. However, this method of firing has serious deficiencies to the extent that it is not an acceptable practice. The deficiencies include loss of furnace pressure on turndown and uncontrolled air leakage around the doors and seals, loss of circulation of furnace gases on turndown leading to poor temperature uniformity, hot spots at the burner locations, and long cycle times. The name of the game in heat treat is close temperature uniformity to assure correct metallurgical properties and the ratio fired approach leads to temperature differences considerably in excess of those acceptable.

Thirty-five years ago, in the days of extremely low cost energy, a simple and highly effective system that overcame all the deficiencies was introduced. This involves setting the combustion air constant at the level required for maximum input and turning down only the fuel as input demand decreases. This system, generally referred to as tempered flame operation,

eliminated all of the problems evident with ratio firing. Cold air infiltration at turndown is eliminated since the volume of products is held essentially constant throughout the cycle and furnace pressure is maintained because of the constant air input. Circulation of furnace gases is maintained almost constant assuring high convection during the soak portion of the cycle. Hot spots at the burners are eliminated since flame temperature decreases to a level just above that of the charge at the end of the soak due to the excess air operation. Tempered flame operation resulted in shorter cycles, by as much as 25% to 50% on stacked charges, with much improved temperature uniformity.

The tempered flame burner capacity was set as much by air requirement for uniformity purposes as by heat balance and the maximum input in many cases was appreciably higher than that required with ratio firing.

This system became the workhorse of the heat treat facility and still is. However, fuel costs have escalated 7 to 8 fold since the mid-forties and can no longer be ignored. The high energy costs of today demand a system which is basically fired near theoretical ratio yet one that assures maintained furnace pressure and high circulation in the chamber and also avoids hot spots at the burner locations.

A new approach called the UNI-HEAT system has been developed recently. The heart of the new system is jet induced circulation of furnace gases in the low flow portion of the cycle. Specifically, ratio fired, high velocity burners are used during the heat up portion of the cycle and high velocity jets are used to induce a high level of furnace gas recirculation during the soak portion. This assures the required high maintained level of circulation in the chamber at both high and low flow, and low flame temperature through entrainment of lower furnace temperature gases.

Figure VII shows the UNI-HEAT burner at

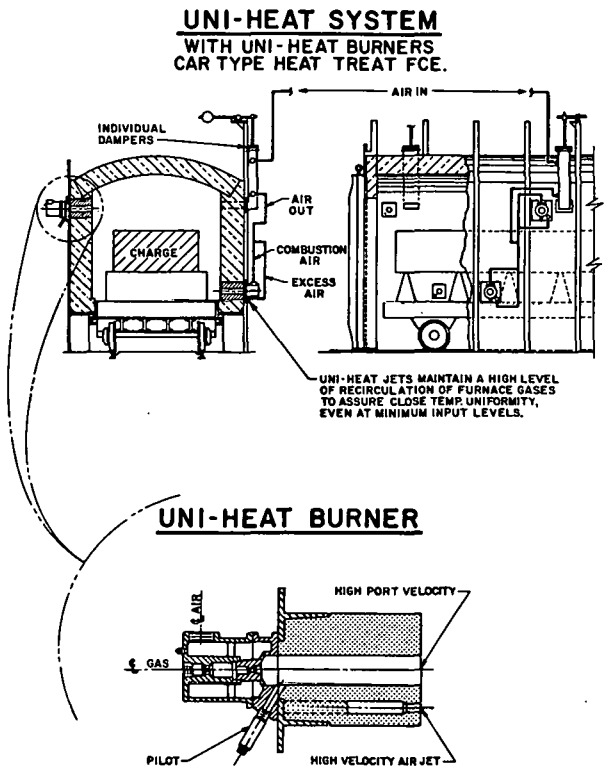


Fig. VII - UNI-HEAT system and burners.

the bottom. It is high velocity clear flame, nozzle mix burner with an air jet incorporated in the port block. The system is shown at the top applied to a car type furnace. Top burners are fired from one side and bottom burners from the opposite side. This is a hot air arrangement with a tube type recuperator connected to a flue port located in the arch. One recuperator feeds two burners, and cap type dampers at the recuperator outlets are used for furnace pressure control.

Figure VIII compares a cold air tempered flame system, a UNI-HEAT hot air system, and hot air ratio firing from the standpoint of fuel consumption based on calculated heat balances. The cycle, which is heat to 1300°F and then soak, is shown on the top. The fuel chart for heat up and soak is shown on the bottom. The tempered flame system used excess air at maximum input, which explains the higher fuel rate, because this was necessary for uniformity reasons. The tempered flame fuel rate during the soak portion is

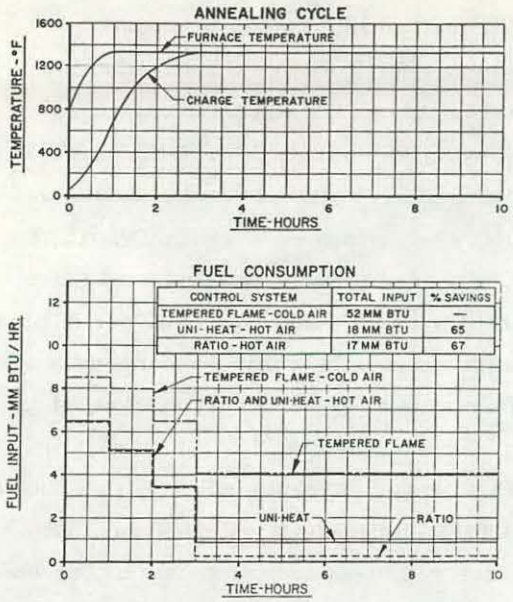


Fig. VII - UNI-HEAT system vs. tempered flame and ratio control for car type furnace.

high since maximum air is heated to furnace temperature. The chart summarizes the total fuel consumption during the cycle and indicates that the UNI-HEAT system does, indeed, approach the efficiency of ratio firing. The result is savings within 2% of that of ratio firing. The thermal efficiency with tempered flame is only 19% and is increased to 54% with a hot air UNI-HEAT system.

Obviously, the amount of savings attainable is dependent on the furnace load and cycle, and will vary from application to application.

A UNI-HEAT system was placed in operation early in 1979 on a 60' car type furnace. The furnace is bottom fired from one side and top fired from the other. A cold air, natural gas combustion system was used with a quantity of forty-eight (48) burners each rated at 250,000 BTU/hr. installed. The burners incorporated a high velocity jet designed for 25% of maximum air flow. Flues are located in the roof with dampers actuated by automatic pressure control.

Figure IX compares the cycle time for the UNI-HEAT system versus tempered flame on the same annealing operation. Cycle time was 27 hours with UNI-HEAT versus 31 hours for tempered flame, a reduction of 13% attributable to faster heat up and equalization of temperature during the soak. Extremely close temperature uniformity was obtained with the UNI-HEAT system during the soak and cooling portion of the cycle.

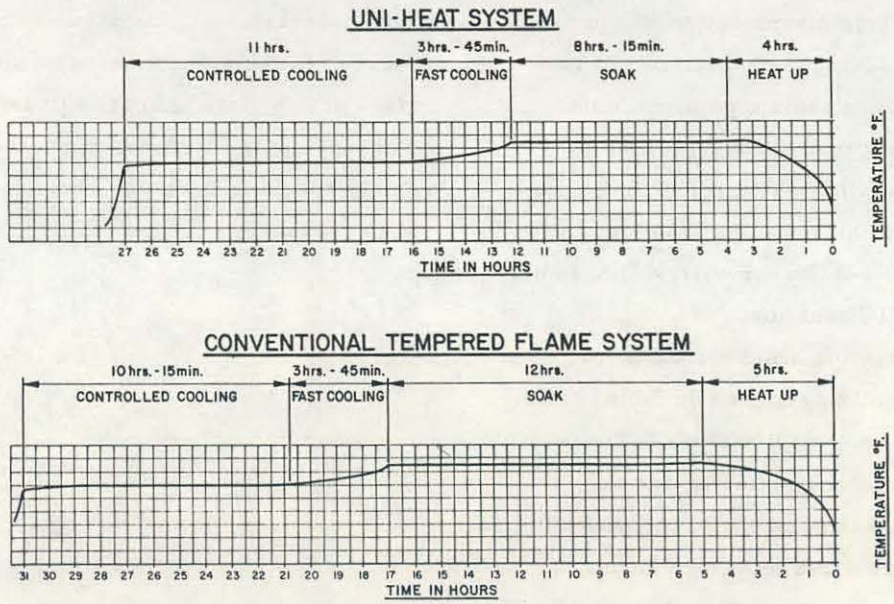


Fig. IX - Furnace time comparisons, UNI-HEAT system vs. conventional tempered flame system for car type annealing furnace.

Total fuel consumption was approximately 132,000 SCF natural gas on tempered flame and 97,000 SCF with UNI-HEAT, a 27% reduction on cold air. This installation saved 35,000 cu. ft. of natural gas on a 30 ton charge or 1.2 MM BTU/ton annealed. A hot air system would give an overall savings of 38% or a total savings of 50,000 cu. ft. of gas or 1670 cu. ft. per ton annealed.

Continuous plate heat treat furnaces offer substantial potential for energy savings. These furnaces are now direct fired with tempered flame or excess air systems, again to assure required temperature uniformity. Fuel input or burner capacity is fixed as much by experience factors, involving cu. ft. of air/ft. of furnace, as by heat balance. The heating requirement is not only tons of plate but equally tons of air. Thermal efficiency is only about 25% on a tempering cycle.

The UNI-HEAT system applied to a 178' long harden/temper/normalizing line when tempering at 800°F and 30 tons/hour will cut fuel consumption by 56% using cold air or 66% with 500°F preheated air compared to cold air tempered flame. This means 460 to 540 cu. ft. of natural gas/ton savings, respectively. The actual dollar savings on this type furnace on cold air would be approximately $150,000 to $200,000 per year with a write-off time of less than one year and $200,000 to $250,000 per year on hot air with 1 to 1-1/2 year write-off based on a $2 per million BTU fuel cost.

Continuous walking beam furnaces for harden/draw/normalizing cycles on tubing offer yet another area of potential savings. These furnaces are often a case of basing burner capacity on a design factor related to cu. ft. of air/ft. of furnace width to assure required temperature uniformity and suffer the consequences with respect to fuel efficiency.

The fuel consumption on a hardening operation at 1550°F with cold air tempered flame calculates to 1.5 MM BTU/ton with a thermal efficiency of only 35%. UNI-HEAT with cold air is 1.0 MM BTU/ton and with hot air 840,000, a savings of 46% with UNI-HEAT hot air compared to tempered flame cold air. Write-off time with a fuel cost of $2 per million BTU in this case is less than 6 months with a cold air system and on a hot air system, about 1 year.

The foregoing clearly indicates that potential savings through conservation measures in the steel industry is real and can be readily accomplished under attractive economic conditions. Some progress has been made since 1973. However, the 90 billion cu. ft. of natural gas is still laying there and additional savings under less attractive justification conditions can be made.

This, in no way, says that basic steel and related industries have been ignoring conservation measures. These industries have been capital poor for years and, until recently, expenditures directed toward energy savings were extremely limited. The industry is still confronted with capital shortage and one prime reason for slow progress in the area of energy conservation is indeed economics. Efforts will be accelerated as energy costs increase, since the industry is rapidly reaching the point where it can't afford not to conserve.

NINETY-TWO PERCENT MINIMUM HEATER EFFICIENCY BY 1980

H.C. Mieth
Energy Technology, Inc., Houston, Tx.

J.E. Hardie
Heat Recovery Corp., Houston, Tx.

Technology is now available to increase heater efficiencies to 92 percent and more. By 1980, this technology will be field proven and corrosion and reliability problems identified and resolved.

Recent studies have shown that a minimum efficiency of 92 percent can be justified on heaters as small as 5 MMBtu/hr. with payouts below 3 years using $2.50/MMBtu fuel costs. Fuel costs continue to rise and many companies feel that $4 to $5 per MMBtu values are only a few years away.

PRIMARY OBSTACLES

At efficiencies over 90 percent, corrosion problems associated with high flue gas dew points due to SO_3 formation from sulfur in the fuel may occur.

Curves in Figs. 1 and 2 (developed by Martin*) can be used to determine safe upper limits for dew points in fired heater applications burning typical fuel oils or gases.

In addition to corrosion problems associated with high efficiencies there has been resistance, particularly in refinery heater service, to dependence on forced draft systems. This natural draft "mainstay" of the process industry seems to be gradually "eroding" as more and more forced draft units come on line and users become familiar with their reliability.

*The John Zink Co., Tulsa, Okla.

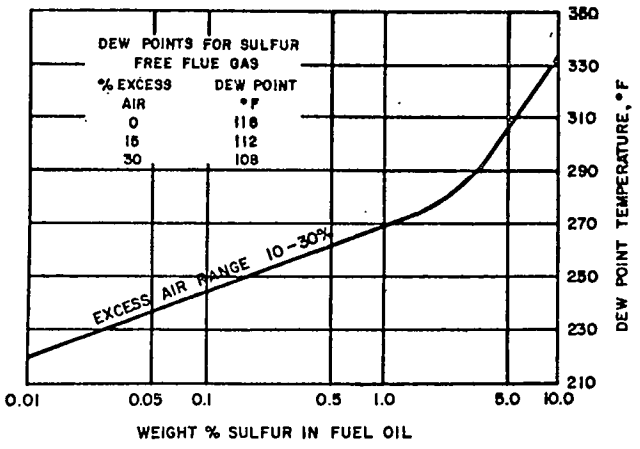


Fig. 1 - Maximum flue gas dew point versus percent sulfer in typical oil fuels.

INCREASING HEATER EFFICIENCY

Additional Convection Surface - The most obvious method of increasing heater efficiency is the simple addition of extra convection section surface for both new and retro-fit units. However, the normal process stream inlet temperature is too high to meet, what most users consider, to be optimum efficiency levels. Auxiliary process streams or feed water preheat can frequently be used to improve this approach.

The most frequent problems associated with this type system are draft limitations and corrosion.

Draft limitations can be solved by increased stack height or applying a forced or induced draft

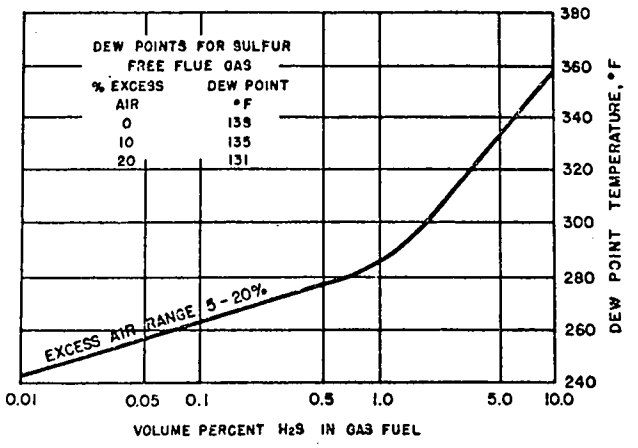


Fig. 2 - Maximum flue gas dew point versus percentage H_2S in typical gas fuels.

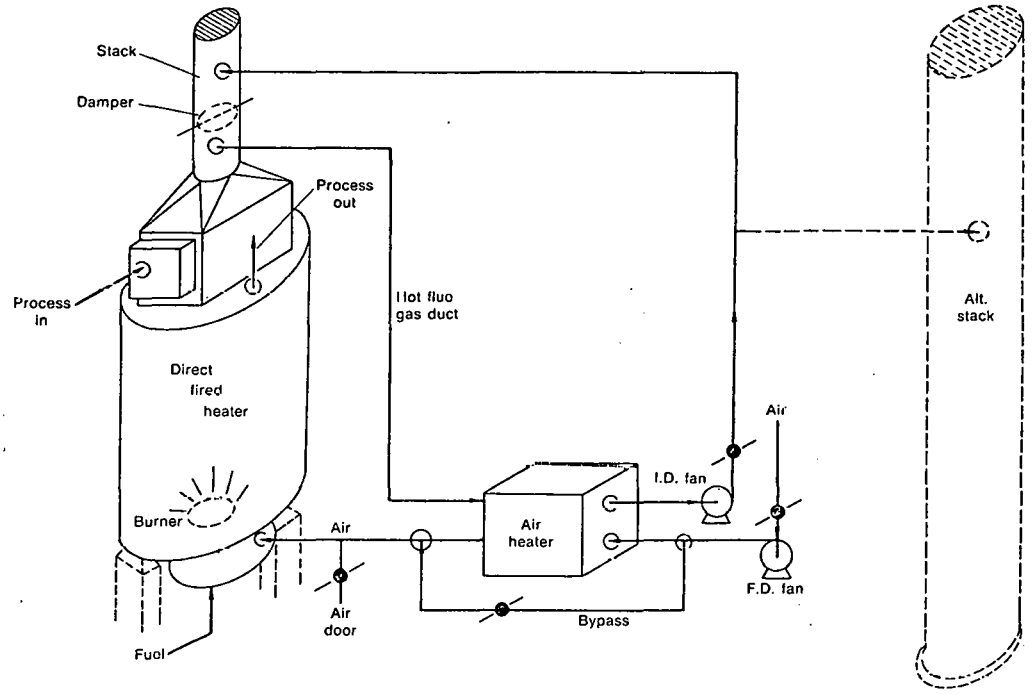


Fig. 6 - Air preheat system, two fans with regenerative or recuperative air heater.

frequently includes provisions for natrual draft operation when the fans or air heater fail or need repair.

The most frequently applied regenerative type has been the rotating mass design. Here, a large mass is rotated between the hot flue gas and cold combustion air streams. Problems in sealing the hot side from the cold side require allowances for leakage which normally results in cold air bypassing directly into the hot flue gas stream which lowers its exit temperature from 15°F to 30°F depending on the application. This, in turn, limits the level of efficiency possible without lowering the exit flue gas below its dew point for the fuel considered. Corrosion will normally occur on the cold end section of the rotated elements due to the necessity of passing through the dew point. Various alloys are used and where fuels containing sulfur are burned, coated elements, e.g., porcelainized enamel, can be very effective against corrosion.

When soot formation is experienced, the rotary regenerative units are equipped with both soot blowers and intermittent wash cycles to clean the elements.

A recuperative air heater is normally a form of gas to gas heat exchanger and ranges in variety from plate to plate type to simple tubular units including cast iron hot end sections with glass and Teflon type cold end sections. Since this is a straight heat exchanger application, sealing the hot and cold side is easily accomplished. Normally, only the exit flue gas dew point limits the efficiency. When the dew point is encountered inside the air heater it can be equipped with proper materials or coatings to protect against corrosion. Experience indicates this corrosion problem can be treated more effectively in the air heater compared to inside the convection section of the fired heater. Soot formation is handled with soot blowers in most cases similar to the techniques used in the convection section of the heater. One proprietary* arrangement used flue gas velocity to keep the tubes swept clean.

The I.D. (induced draft) fan, normally located on the exit flue gas side of the air heater, can be located on the hot flue gas side if needed to eliminate fan corrosion. The exit duct and stack system is normally lined to guard against corrosion from further cooling of the exit gas when it is near the dew point.

This type application can achieve 92 percent efficency and higher without reaching the exit flue gas dew point on most sulfur-containing fuels presently

*Energy Technology, Inc., Houston.

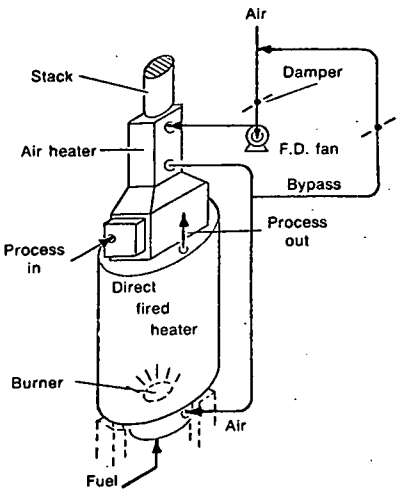


Fig. 7 - Air preheat system with one fan with recuperative air heater.

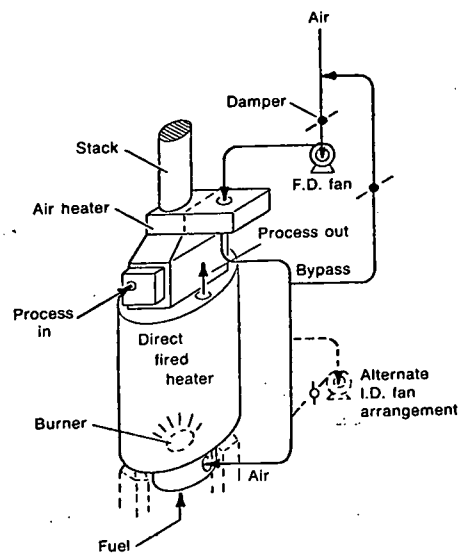


Fig. 8 - Air preheat system, one fan with regenerative air heater.

allowed by the various air quality agencies. Studies are now being made for even higher efficiencies using fiberglass or other exit system materials to protect against corrosion when operating below the dew point of the exit flue gas. Consideration must also be given to the disposal of any weak sulfuric acid condensate that must be drained from applications where the exit flue gas is cooled below its

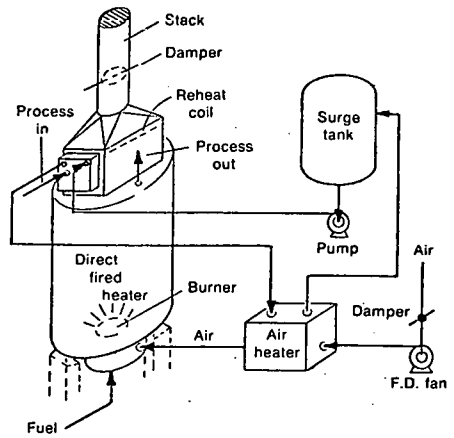


Fig. 9 - Air preheat system, one fan recirculating oil with recuperative air heater.

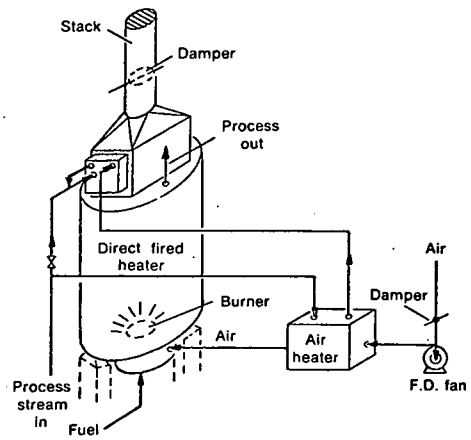


Fig. 10 - Air preheat system, one-fan slip stream with recuperative air heater.

dew point.

Fig. 7 shows a single F.D. (forced draft) fan system with a typical recuperative air heater. There are numerous suppliers of gas to gas heat exchangers and most of these can be adapted to this configuration. Rather than provide for natural draft as an alternate operating mode, a spare fan can be used where reliability is essential. The system can be rearranged using a single I.D. fan for negative firebox operation.

This type system can achieve very high efficiencies and has been economically applied to units operating below 10 MMBtu/hr. design capacity. Corrosion

and cleaning problems can be isolated within a very small region in this arrangement and are being treated by new techniques. Although not fully supported by field experience at this time, early feedback is very encouraging.

A variation of a single fan system is shown in Fig. 8. It is very similar to the system in Fig. 6, but uses a regenerative air heater. This type heat exchanger is commonly referred to as a "heat pipe." The basic "heat pipe" consists of a closed envelope (normally a tube) containing a capillary wick with a suitable fluid. The "heat pipe" employs a boiling condensing cycle with the capillary action moving the condensed fluid back from the cold end (air side) to the hot end (flue gas side). The pressure loss between the evaporating and condensing end of the tube is so small the cycle is essentially an isothermal process. Although the design has been known for many years, its use in a fired heater air preheat system has only recently been applied.

Another single fan system is shown in Fig. 9. This system is regenerative in nature when viewing the overall system, but uses a recuperative air heater to preheat the combustion air. This arrangement is normally referred to as a hot oil recirculating system. High temperature limitations on the circulating oil tend to limit the hot flue gas inlet temperature. In addition, the cold end of the reheat coil is limited by corrosion problems discussed earlier in the section on added convection surface.

These limitations usually restrict this type system to efficiencies in the 90-91 percent range. However, good results can be achieved with relatively low flue gas inlet temperatures.

Fig. 10 depicts a proprietary* system which uses the process feed stream to preheat the combustion air. System efficiencies and inherent limitations are similar to those described for the hot oil circulating system above. However, since the oil stream is continuously replaced and the auxiliary equipment requirement is normally reduced, it can have advantages over a closed loop system when terminal temperatures are optimum.

Fig. 11 shows that in addition to the various systems discussed, any other available heat source may be used to provide air preheat. However, caution should be exercised to insure that overall fuel savings can be achieved when external sources are considered.

*Heat Research Corp., New York.

POLLUTION CONTROL VERSUS ENERGY CONSERVATION

A carefully designed, automated, high efficiency heater system can reduce air pollution for the same process duty versus the normal operation and control previously followed. This subject is far too complex to discuss in detail here. However, a few points can be presented in the stack emissions from fired heaters:

1. Sulfur expressed as SO_2
2. Oxides of nitrogen expressed as NOx
3. Particulates expressed as solids
4. Unburned hydrocarbons expressed as combustibles.

The sulfur depends primarily on the fuel burned and is not affected to any extent by the heater application. However, since fuel consumption is reduced when efficiencies are increased, the pounds of SO_2 emitted are reduced for the same process duty. This results in a new reduction in pollution.

The oxides of nitrogen (NOx) produced depend on the time, temperature and oxygen concentration during combustion of any specific fuel. The reactions involved and their behavior are many and complex. Generally,

1. NOx produced goes up with an increased firebox and/or combustion temperature.
2. NOx produced goes down with a decrease in excess air.

This would indicate that preheating the combustion air can increase the NOx produced. This has been proved when expressed as parts per million in the exit flue gas. However, as in the case of sulfur, the pounds of nitrogen oxides expressed as NO_2 emitted are reduced as efficiency is increased. This tends to offset the adverse effect of air preheat and can, in cases where efficiencies are dramatically improved, reverse the overall impact.

Excess air appears to be the most significant factor in the control of NOx production. Since most high efficiency heater applications tended to encourage the use of forced draft burners, it is not only possible to operate at extremely low excess air levels, but also to more accurately control the fuel air ratio. On natural draft systems the minimum excess air levels previously considered necessary to provide for operational variations have been 20 percent

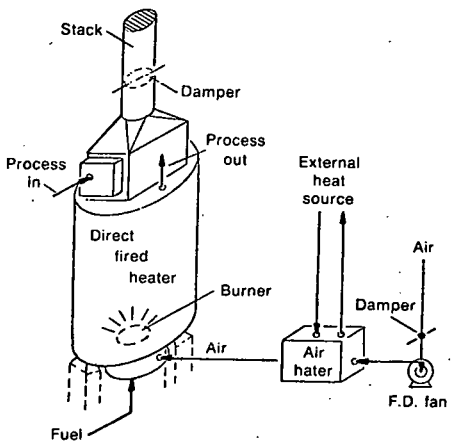


Fig. 11 - Air preheat system, one-fan external heat source with recuperative air heater.

on gas fuels and 30 percent on oil fuels. Most burner manufacturers represent that using their forced draft designs and preheated air requires minimum excess air levels of only 5 percent on gas and 10 percent on oil fuels, and controls can be furnished to insure these levels. This low excess air operation will significantly reduce the NOx level.

Particulates are related principally to oil fuels and the ability to burn these fuels without soot formation releated to incomplete combustion. Preheater air and forced draft systems have allowed burner manufacturers to all but eliminate this problem. A well designed high efficiency heater system using preheated air and modern burner technology can reduce the particulate emission to essentially that corresponding to the fuel ash and sediment content.

Unburned hydrocarbons normally are related to the level of excess air used and the degree of difficulty in burning the fuel in question. Preheated air and forced draft systems have also improved the burner manufacturers' ability to reduce combustibles below trace levels when operating at the low excess air levels mentioned above.

Many designers now feel that energy conservation can be improved dramatically in fired heater applications while actually decreasing the resultant total pollution emissions for any given process service u any specific fuel.

EC IC CONSIDERATIONS

The average cost of fuel now being used to evaluate heater efficiency economics is nominally $2.50/MMBtu. This value according to many users could double over the next few years.

Previously, achieving higher heater efficiencies by using steam generation of air preheat was normally considered only on larger heaters. Many users felt a 50-MMBtu/hr. process duty was the break point. It now appears there may not be a break point. Most heaters should show a good return for increasing their efficiency up to 92 percent. For example, a 5 MMBtu/hr. heat medium heater which would cost approximately $30,000 new, less controls. At a nominal 400°F inlet temperature, this unit would have previously been designed for a maximum efficiency of around 84 percent. Using the $2.50 fuel cost and a minimum 3 - year pay-back period, there would be $34,000 available to spend for increasing the efficiency from 84 to 92 percent. There are three obvious points.

1. The 3 year fuel savings is greater than the initial cost of the heater.
2. Normally, a simple air preheat system can be added for less than the cost of a new heater.
3. Future savings will undoubtedly be greater due to fuel cost increases.

(Adapted from the paper "92% Minimum Heater Efficiency by 1980" by H.C. Mieth and J.E. Hardie, originally presented before the API 44th Midyear Refining Meeting, San Francisco, May 15, 1979.)