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District Heating/Cogeneration Application Studies for the Minneapolis-St. Paul Area

Modifications of the Existing Units at the High Bridge Power Plant to Cogeneration for Hot Water District Heating

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DISTRICT HEATING/COGENERATION APPLICATION STUDIES FOR THE MINNEAPOLIS-ST. PAUL AREA

MODIFICATIONS OF THE EXISTING UNITS AT THE HIGH BRIDGE POWER PLANT TO COGENERATION FOR HOT WATER DISTRICT HEATING

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United Engineers and Constructors Inc.

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FOREWORD

District heating is generally defined as the distribution of thermal energy from a central source for residential and commercial space heating. The central source is usually a heat-only unit or a cogeneration dual-purpose facility that produces both electricity and thermal energy. The most significant advantage of cogeneration power plants compared to conventional steam-electric generating stations is the improved fuel utilization efficiency. Figure F.1 shows graphically the comparative efficiencies of both types of plants. The overall conversion efficiency of an electric-only plant is about 33%. The remaining two-thirds of the energy is rejected to the environment through once-through cooling

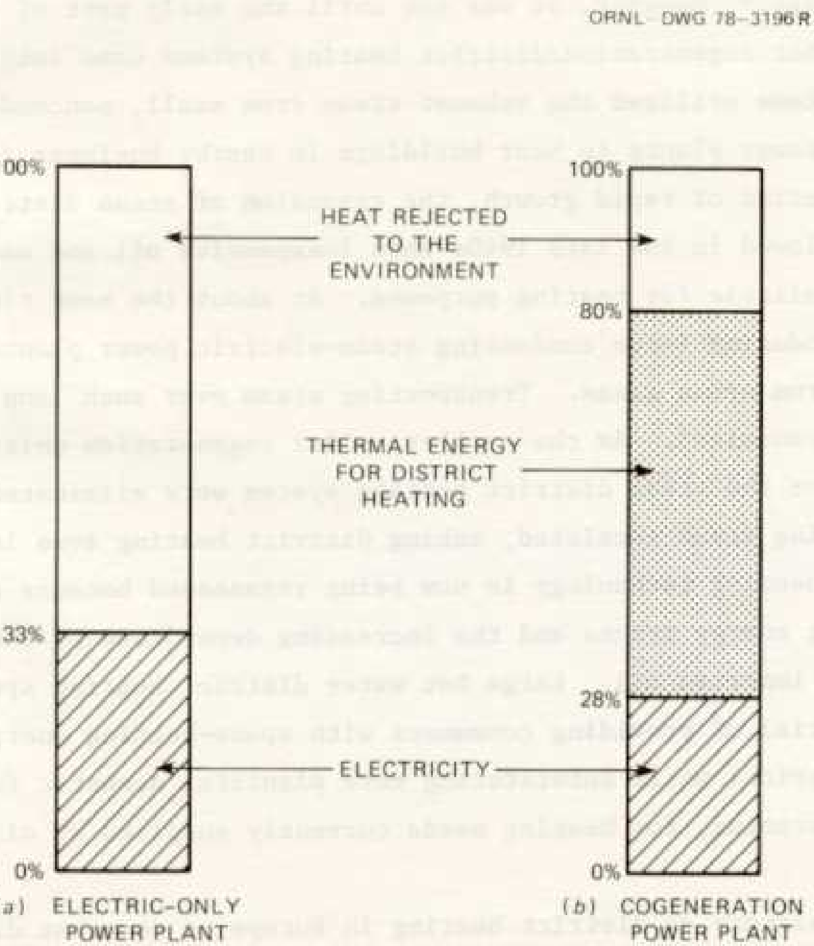

Fig. F.1. Comparison of fuel utilization of electric-only and cogeneration power plants.

systems or cooling towers at about 308 to 313 K (95 to 104°F). A cogeneration power plant, on the other hand, can operate at an overall efficiency as high as 85%, but this requires some sacrifice in electric output. To supply thermal energy at a temperature level high enough for district heating (e.g., 100°C), steam must be extracted from the power plant's turbine before it has expanded to its full potential. Therefore, there is some reduction in the power output of the turbine which, in turn, reduces the quantity of electricity generated. However, for each unit of electric energy sacrificed, 5 to 10 units of thermal energy are available for district heating.

District heating has been in existence for approximately 100 years. In 1877, a short underground steam pipe was installed in Lockport, New York, to transport thermal energy from a central source to heat a group of buildings.[1] However, it was not until the early part of the twentieth century that cogeneration/district heating systems came into existence. These systems utilized the exhaust steam from small, noncondensing steam-electric power plants to heat buildings in nearby business districts. After a period of rapid growth, the expansion of steam district heating systems slowed in the late 1940s when inexpensive oil and natural gas became available for heating purposes. At about the same time, utilities were introducing large condensing steam-electric power plants remotely located from urban areas. Transporting steam over such long distances was not economical. As the smaller, older cogeneration units were retired, sources for the steam district heating system were eliminated and the cost of supplying steam escalated, making district heating even less attractive. District heating technology is now being reassessed because of rapidly escalating energy prices and the increasing dependence of the United States on imported oil. Large hot water district heating systems have the potential of providing consumers with space-heating energy at competitive prices while substituting more plentiful domestic fuels, such as coal and uranium, for heating needs currently supplied by oil and natural gas.

The history of district heating in Europe is somewhat different than that of the United States.[2] Most of the development of large district heating networks in Europe took place after World War II. This development has been due in large part to high energy prices and a scarcity of alternative heating options, such as natural gas. These factors, although new to the United States, have been strong motivation for the expansion of district heating technology in Scandinavian and other northern European countries. Their district heating technology uses hot water as the distribution media. Hot water was chosen over steam for its flexibility and adaptability to long-distance transport. Over the past 20 years, technology and hardware have been developed that successfully provide large-scale hot water district heating.

Northern States Power Company (NSP), the Department of Energy (DOE), the Minnesota Energy Agency (MEA), the Minnesota Gas Company, the Minneapolis Central Heating Company, the University of Minnesota, and other local governments and private organizations are cooperatively performing an in-depth application study to determine the feasibility of

Table F.1. Minneapolis-St. Paul district heating studies

Studies	Sponsor
Distribution and building systems	
Studsvik district heating study (overall feasibility study outlining 20-year development)	DOE
Building conversion study (description of conversion techniques and estimation of costs)	DOE
The feasibility of district heating in St. Paul	NSP
Energy sources studies	
Retrofiting an existing coal plant (description of conversion techniques and costs for High Bridge Power Plant in St. Paul)	NSP
New coal/cogeneration plant assessment (investigation of the possibility of locating a new coal-cogenerating unit near or in the Twin Cities)	NSP and DOE
Institutional issues	
Ownership option and barriers (identification and evaluation of nontechnical issues: ownership, financing, regulation, and marketability)	DOE
Environmental	
Air-quality modeling (prediction of the effect of cogeneration/district heating on Twin Cities air quality)	DOE and EPA

hot water district heating for a large U.S. metropolitan area — namely, Minneapolis-St. Paul, Minnesota. The program to assess district heating for the Twin Cities area consists of several coordinated studies focusing on technical, economic, environmental, and institutional issues. A list of the various studies is given in Table F.1. The stimulus for most of the Twin Cities work has been the Overall Feasibility Study[3] done by Studsvik Energiteknik AB, Sweden.

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1. National District Heating Association, *District Heating Handbook*, 3rd ed., Pittsburgh, 1951.

2. V. Scholten, "Survey about the Existing District Heating Systems," presented at a topical meeting on Low-Temperature Nuclear Heating, Otaniemi, Finland, Aug. 21-24, 1977.

3. Peter Margen et al., *Overall Feasibility and Economic Viability for a District Heating/New Cogeneration System in Minneapolis-St. Paul*, ORNL/TM-6830/P3 (August 1979).

EXECUTIVE SUMMARY

Introduction

District heating (DH) from cogeneration offers a unique opportunity to energy users by combining energy conservation, environmental enhancement, and improved economics. Energy is conserved by replacing energy produced directly from fuel with heat normally wasted from steam electric plants. Cogeneration also permits the substitution of coal, an abundant resource, for oil and gas which are in limited supply. Because the energy is produced at a single source, advanced pollution control equipment can reduce both emissions and water use.

The Northern States Power Company (NSP) can start a cogeneration program by converting existing steam electric generating equipment located next to a proposed DH system. The NSP commissioned United Engineers & Constructors Inc. (UE&C) to prepare a preliminary design and cost estimate for cogeneration at the High Bridge Generating Station.

Scope of the Program

The scope of the work effort consisting of approximately 3000 technical manhours over a six-month period, included:

1. review of previous work by C. T. Main, Studsvik, and Ekono,
2. an assessment of the mechanical status of the units at the High Bridge Station,
3. development of a conversion plan for a cogeneration-DH operation,
4. consultation with the manufacturers of the turbine-generator equipment to be converted,
5. development of control and operating plans,
6. preparation of an allocation method for estimating electricity and heat costs (described in a separate report),
7. preparation of a preliminary design, drawings, and construction sequence, and

8. estimation of capital and operating costs for cogenerated heat.

Assessment of the High Bridge Generating Station

The assessment of the units at the High Bridge plant to determine their suitability for conversion to cogeneration required an examination of the equipment, discussions with NSP operating and maintenance staff, discussions with major vendors of the operating equipment, evaluation of operating reports, and examination of the drawings and technical manuals.

This assessment determined that units 3, 5, and 6 would be recommended for conversion to cogeneration. This recommendation is based on the generally high availability of these units, the low maintenance cost to keep this availability, and the total heat available. Unit 4 is not recommended for conversion because of its lower availability, the cost projected to improve its availability, and the absence of the need for additional base load heat capacity.

Conversion Description and Construction Plan

With this conversion concept (Fig. 1), unit 3 would be converted to a back-pressure operation by removal of a portion of the low-pressure blading. It is not amenable to steam extraction because of the turbine casing design. Unit 3 will supply the base heat load.

Units 5 and 6 will be converted to condensing-tail operation by the installation of a variable steam bypass in the external crossover piping between the high-pressure and low-pressure casings. In the case of units 5 and 6, the conversion to condensing tail is less expensive than conversion to back-pressure operation. Also, condensing-tail retrofitting permits the units to be operated in the summer without loss of electrical capacity.

Unit 6 will be the first unit to be converted, followed by units 3 and 5. Conversion of units 5 and 6 will be scheduled to coincide with a routine outage. Unit 3 conversion will require outage of the unit for approximately four months while major turbine modifications are made. Construction would be scheduled so as to have minimum interruption of station operation.

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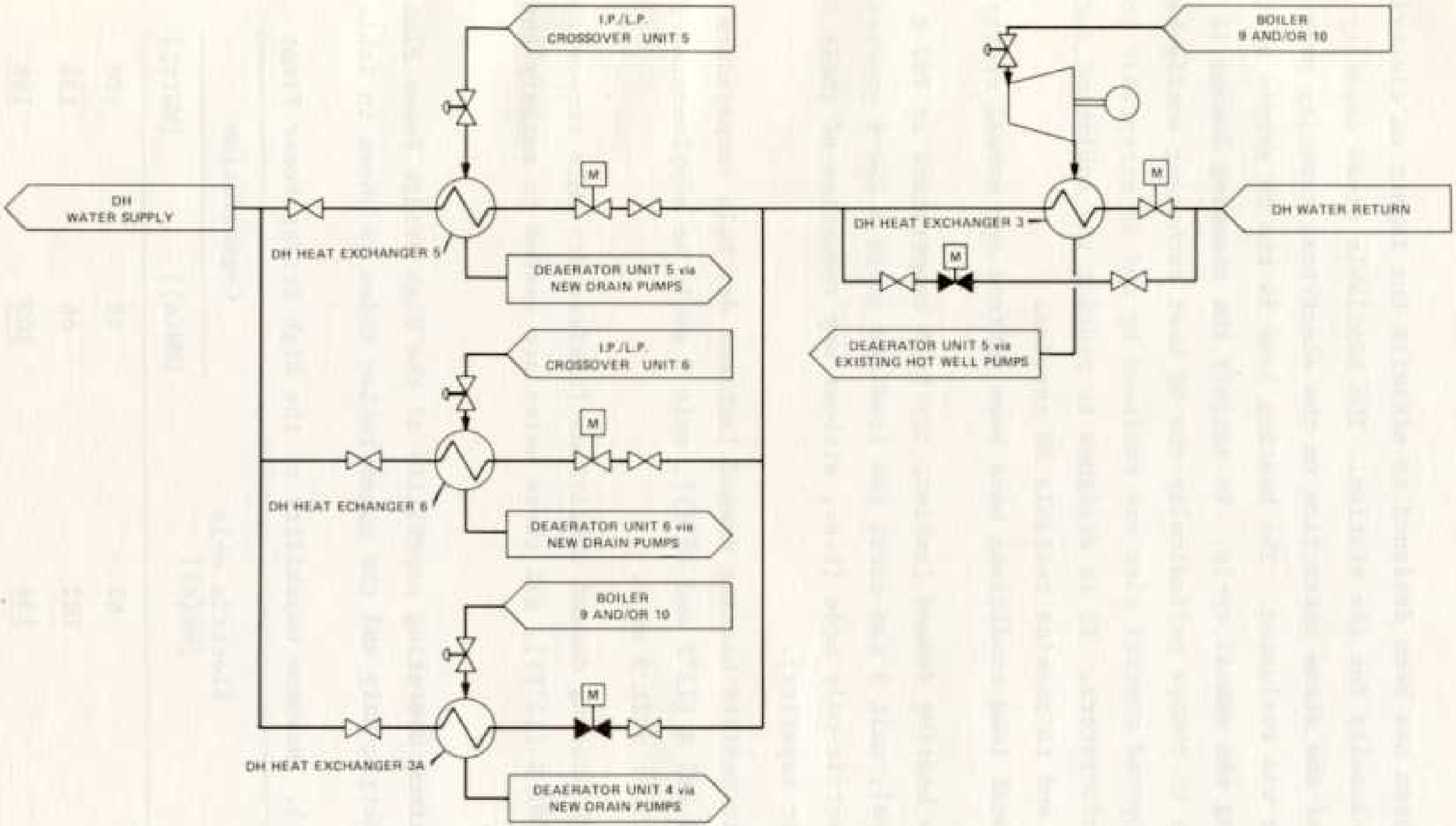

Fig. 1. Water flow for the High Bridge cogeneration retrofit.

Plant Operation and Performance

The system has been designed to minimize the impact on electric generating capacity for the station. The available steam capacity and the impact of the steam extraction on the electrical capacity over the annual cycle was evaluated. The heating load in the DH system varies widely during the annual cycle. To satisfy the changing demand it will be necessary to change periodically the DH heat exchanger configuration.

The proposed control plan was reviewed by and is acceptable to the turbine manufacturers. It is designed to protect the equipment during upset conditions, and to provide reliable DH service.

Three heat load conditions have been defined for normal operation:

1. For low heating demand [ambient dry bulb temperature at 282 K (48°F) or above], unit 3 can carry the load and units 5 and 6 operate in the electric-only mode (i.e., without any reduction of their current electric capacity).

2. For intermediate heating demand [ambient dry bulb temperature between 261 and 282 K (11°F and 48°F)], unit 3 would be supplemented with heat from either unit 5 or 6.

3. For high heating demand conditions [ambient dry bulb temperature below 261 K (11°F)], all three units are needed to satisfy the heat demand.

The maximum operating capability of the High Bridge Power Plant in both the electric-only and the cogeneration modes is shown in Table 1.

Table 1. Maximum capability of the High Bridge Power Plant

Unit	Electric only [MW(e)]	Cogeneration	
		[MW(e)]	[MW(t)]
3	62	49	120
5	102	66	138
6	156	109	186
Total	320	224	444

Capital and Operating Costs

A capital cost estimate was prepared (Table 2). The costs are based on 1978 equipment prices and labor rates and include indirect costs such as engineering and construction management. The NSP provided projected major maintenance costs to keep the units at existing operational status. These costs have been included in the estimate.

The operating costs for electricity and heat production were developed using a method of cost allocation which maintains electrical costs equal to the costs from separate electrical generation. For this evaluation, no capacity loss or replacement energy penalty costs due to the permanent derate of unit 3 or winter derate of units 5 and 6 were included. The resultant heat costs are less than half those from separate heat generation (Table 3). This allocation method should encourage conversion to DH, but not penalize electric customers.

Table 2. Estimated costs of retrofitting the High Bridge Generating Station (Units 3, 5 and 6)

Equipment	Retrofit cost ($)	Refurbishment cost[a] ($)
Structures and improvements	30,000	
Boiler plant equipment	4,105,000	2,450,000
Turbine-generator units	2,880,000	
Accessory electric equipment	315,000	
Total direct costs	7,330,000	2,450,000
Total indirect costs	620,000	200,000
Total direct and indirect costs	7,950,000	2,650,000
Contingency	1,050,000	350,000
Total	9,000,000	3,000,000

[a]Consists of costs required to restore the boilers to a condition necessary to extend their useful operating life beyond the normal retirement date.

Table 3. Annual production costs for High Bridge Generating Station, units 3, 5, and 6, as functions of the electric power capacity factors

Electric power capacity factor (%)	Electric power unit cost (mills/kWh)	Thermal energy unit cost ($/GJ)		
		Fixed	Operating	Total
100	12.97	0.55	0.44	0.99
90	13.39	0.55	0.44	0.99
80	13.90	0.55	0.44	0.99
70	14.56	0.55	0.44	0.99
60	15.44	0.55	0.43	0.98
50	16.68	0.55	0.43	0.98

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50	16.68	0.55	0.43	0.98

ACKNOWLEDGMENTS

This study of retrofitting the High Bridge Station to cogeneration operation was done by United Engineers and Constructors Inc. (UE&C) for the Northern States Power Company (NSP).

The study was directed by G. A. Englesson of UE&C. Other major UE&C contributors were M. C. Casapis, L. Denesdi, B. Menaker, G. F. Pavlenco, and D. E. Williamson.

Both H. Jaehne and P. Johnson of NSP provided data and advice.

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ABSTRACT

The electrical generating turbines at the High Bridge Generating Station were evaluated for their suitability for conversion to cogeneration. This evaluation required examinations of the equipment, the operating reports, and the technical manuals and drawings. The evaluation also included discussions with the plant staff and with the major vendors of the operating equipment.

Units 3, 5, and 6 were recommended for conversion to cogeneration — unit 3 to be converted to back-pressure operation and units 5 and 6 to be converted to condensing-tail operation. Unit 4 was not recommended for conversion.

1. INTRODUCTION

Cogeneration is the simultaneous production of electricity and heat from a slightly modified electric generating unit. Cogeneration for district heating (DH) offers a unique opportunity to energy users by providing a combination of energy conservation, reduced environmental impact, and potentially improved economics. Energy is conserved by replacing heat from fuel now burned for space heating with waste heat from steam electric plants. Cogeneration also permits substitution of coal, an abundant resource, for oil and gas which are in limited supply. Environmentally, cogeneration replaces scattered low-level sources with single sources that are amenable to advanced emission controls and use less water.

For the Northern States Power Company (NSP) project in St. Paul, interim solutions may be advantageous for meeting near-term heat and electric loads, while allowing time for more detailed planning of long-term solutions. This situation is exemplified by retrofitting existing units that have passed their prime as electric-generation units but that can still be used as cogeneration units.

2. BACKGROUND AND SCOPE

2.1 Background

Several feasibility studies for DH and for cogeneration have been conducted of the Minneapolis-St. Paul area. Because of the proximity of the two downtown sections, linked by industrial sites and residential areas, the high-population and heat-density areas coincide. The population of the cities and their suburbs exceeds one million. With the consistently cold climate and the willingness of local governments and utilities to participate, the Twin Cities are potentially a prime location for DH and cogeneration.

Studsvik (formerly A. B. Atomenergi) of Sweden recently completed a study of the DH potential in the Minneapolis-St. Paul area.* The conclusions were that both DH and cogeneration are technically feasible, large quantities of scarce fuel can be saved, and the economics are favorable. An incidental conclusion was that existing electrical generation plants can be retrofitted to produce heat prior to the construction of new cogeneration facilities.

A 1977 study conducted by Ekono Inc. of Finland assessed the heat-generation capabilities of the High Bridge and Riverside plants. Those existing NSP coal-fired electricity generating plants are within the city boundaries, ideally situated to supply heat to a DH system. Existing condensing turbines at these plants could be converted to supply heat to a hot water DH system. The study concluded that the converted units could provide large amounts of heat; however, consideration was not given to the mechanical condition of the units, nor to the load limits imposed by the present boiler fuel. Also, the economics of the conversion were not considered.

The NSP hired United Engineers & Constructors Inc. (UE&C) to prepare a conceptual design and cost estimate for converting the High Bridge

*Peter Margen, Lars-Åke Cronholm, Kjell Larsson, and Jan-Erik Marklund, *District Heating/Cogeneration Application Studies for the Minneapolis-St. Paul Area; Executive Summary: Overall Feasibility and Economic Viability for a District Heating/New Cogeneration System in Minneapolis-St. Paul*, ORNL/TM-6830/P2, August 1979.

plant to cogeneration and to estimate the resulting unit cost of heat and electricity. The High Bridge plant was chosen as the candidate plant because it is coal fired, can produce sufficient heat, and is close to the high thermal density St. Paul area. The NSP also hired C. T. Main, Inc., to evaluate the feasibility of a DH system for the downtown St. Paul area which will be served by the converted High Bridge station.

Most of the heat-load demand in the Twin Cities is presently served by natural gas. In the winter the gas supply to large customers is interrupted, and oil is used as the replacement fuel. By shifting the heating load to a coal-fired unit such as the High Bridge plant, Minneapolis and St. Paul would depend less on gas and oil.

The High Bridge Generating Station is a coal-fired steam-electric generating plant located in downtown St. Paul using the Mississippi River for cooling. It consists of four generating units — 3, 4, 5, and 6. Units 1 and 2 have been retired, and the turbine-generators, condensers, and ancillary equipment have been removed. The boilers remain in place, although they are not usable. Units 3 and 4 have identical 21-stage single-case double-flow exhaust turbines with once-through condenser cooling. Feedwater is heated in four regenerative stages. Main steam conditions are 6 MPa (850 psig) at 755 K (900°F) with no reheat. Condenser-exhaust pressure is 5 kPa (1.5-in. HgA). Each unit is rated at 50,000 kW(e) but is capable of producing 62,500 kW(e). Unit 3 was built in 1942 and unit 4 in 1944. These units operate as peaking units, approximately 5 d/week. The combined capacity factor for both units during 1977 was 26.9%. The turbines were manufactured by General Electric Company and the boilers by Babcock and Wilcox.

Unit 5 has a three-case tandem-compound double-flow exhaust turbine with once-through condenser cooling. Feedwater is heated in five regenerative stages. Steam conditions are 10 MPa (1450 psig) at 811 K (1000°F) at the throttle with a single reheat to 811 K (1000°F). Condenser exhaust pressure is 5 kPa (1.5-in. HgA). The turbine-generator is rated at 90,909 kW(e) and has a maximum capability of 102,152 kW. Unit 5, built in 1956, is used to meet peak demands and had a 1977 capacity factor of 48.4%. The turbine-generator was manufactured by Allis-Chalmers and the boiler by Babcock and Wilcox.

Unit 6 has a three-case tandem-compound double-flow exhaust turbine with once-through condenser cooling. Feedwater is heated in six regenerative stages. Steam conditions are 12.5 MPa (1800 psig) at 811 K (1000°F) at the throttle with a single reheat to 811 K (1000°F). Condenser exhaust pressure is 5 kPa (1.5-in. HgA). The turbine generator is rated at 156,250 kW(e). Unit 6, built in 1959, supplies the base load 5 d/week. The 1977 capacity factor was 54%. Unit 6 has a General Electric turbine generator and a Babcock and Wilcox boiler.

2.2 Scope

The development of a concept for the heat source required completion of several tasks. Because the background work and the heat-load calculations had been done by others, UE&C was required to become familiar with this work and conduct reviews and evaluations. Also, the physical condition of the High Bridge units and their suitability for conversion were assessed. The heat-source concept was then developed in sufficient detail to guarantee both the feasibility of the plant retrofit and the reasonable accuracy of the cost estimates. As part of the concept development, UE&C prepared arrangement drawings, process and instrument diagrams, heat-balance diagrams, and a major equipment list. To assess the condition of the existing units and their feasibility for conversion, UE&C inspected the station, interviewed operating and maintenance personnel, reviewed available station operating records, and contacted the manufacturers of the major station equipment to obtain pertinent information.

Capital costs for the conceptual design were estimated and brief specifications were prepared for major items of equipment and quotations solicited from recognized vendors. Unit costs for heat and electricity were calculated.

3. TURBINE-CONVERSION METHODS AND CRITERIA

When converting an existing condensing turbine for cogeneration and hot water DH, two basic arrangements are available — straight back pressure (Fig. 3.1) and condensing tail (Fig. 3.2). Each has advantages and disadvantages. Preference for one or the other depends upon the particular circumstances.

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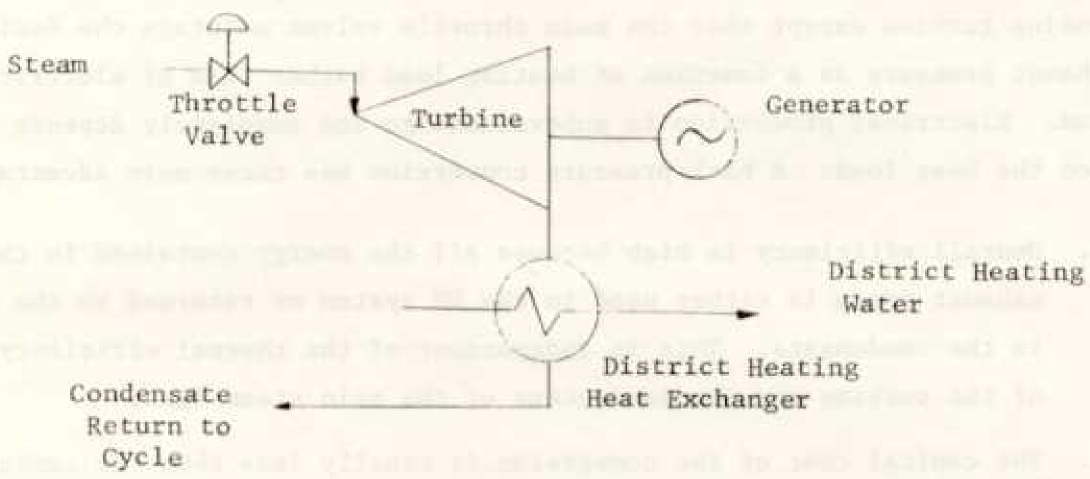

Fig. 3.1. Converted back-pressure cogeneration turbine.

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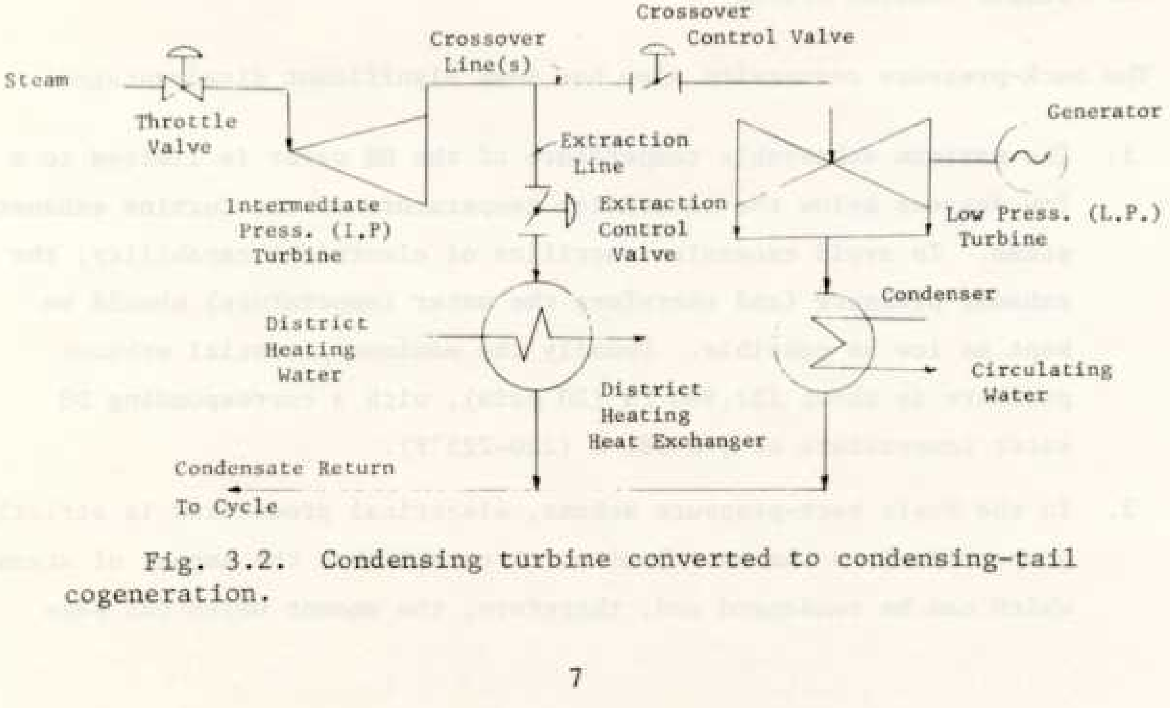

Fig. 3.2. Condensing turbine converted to condensing-tail cogeneration.

3.1 Straight Back Pressure

The conversion of a turbine to back-pressure cogeneration requires the removal of several low-pressure stages, which increases the exhaust pressure sufficiently to heat the district heating water to the desired temperature. The existing condenser will usually be replaced with a DH heat exchanger. The turbine will then exhaust directly into the heat exchanger.

The back-pressure turbine operates similarly to the original condensing turbine except that the main throttle valves maintain the desired exhaust pressure as a function of heating load rather than of electrical load. Electrical production is subordinate to and completely depends upon the heat load. A back-pressure conversion has three main advantages:

1. Overall efficiency is high because all the energy contained in the exhaust steam is either used in the DH system or returned to the cycle in the condensate. This is independent of the thermal efficiency of the turbine and the parameters of the main steam flow.
2. The capital cost of the conversion is usually less than for conversion to a condensing-tail turbine.
3. In its basic form, a back-pressure conversion requires a comparatively simple control system.

The back-pressure conversion also has some significant disadvantages:

1. The maximum achievable temperature of the DH water is limited to a few degrees below the saturation temperature of the turbine exhaust steam. To avoid excessive sacrifice of electrical capability, the exhaust pressure (and therefore the water temperature) should be kept as low as possible. Usually the maximum potential exhaust pressure is about 137,900 Pa (20 psia), with a corresponding DH water temperature of 378–381 K (220–225°F).
2. In the basic back-pressure scheme, electrical production is strictly proportional to the heat load which establishes the amount of steam which can be condensed and, therefore, the amount which can pass

through the turbine. For any turbine-generator of significant size, this is undesirable since heat load and, therefore, electrical production will be lowest in summer, when most U.S. utilities experience maximum electrical demand. When thermal load is low, electrical production can be increased by several methods. Excess steam can be exhausted to an auxiliary condenser, or the heat load can also be increased by cooling the incoming DH water with an auxiliary heat exchanger. Each of these modifications is undesirable because of the added complication and cost of the conversion. Electricity produced by either of these methods will also be more expensive than that produced with a standard condensing turbine.

3. Because some turbine stages have been removed and the turbine must always operate at an elevated back pressure, there is a permanent loss of electrical capacity.

3.2 Condensing Tail

Conversion of an existing condensing turbine to a condensing-tail cogeneration turbine (Fig. 3.2) requires installation of a control valve in an interstage steam crossover line and the addition of an extraction connection also in the crossover, and an extraction control valve. (Because a minimum steam flow to the low-pressure turbine is required to cool the blading, it is essential that a minimum leakage through the valve be provided.) A DH heat exchanger and control valve in the steam extraction line complete the conversion.

There are two operating modes for a condensing-tail turbine — electric only and cogeneration. In the electric-only mode, controls and operation are identical to the unaltered turbine — the extraction control valve is closed, the crossover control valve is fully open, and no heat is supplied to the DH system. When operating in the cogeneration mode, either the electrical demand or the heat demand will take precedence depending upon the specific control system design; however, the control system will accommodate both demands (within the range of capabilities of the turbine).

The condensing-tail conversion offers several significant advantages:

1. No electrical capability is permanently lost. Any time the turbine is not required to satisfy a heat demand, the turbine can be operated in the electric-only mode as if it had not been altered.
2. Because the steam is extracted from the intermediate-pressure-to-low-pressure crossover, no unbalanced thrust loads are introduced to the turbine bearings (assuming a two-flow low-pressure turbine such as the High Bridge units 5 and 6). Mechanical modifications of the turbine are minimized.
3. Higher water temperatures are more feasible than with back-pressure turbines, because of the higher temperature and pressure of the cross-over steam.
4. Electricity and heat are not produced in a fixed ratio but can be varied over a range. This variation provides more operational flexibility to accommodate system load requirements.

There are also disadvantages:

1. Major control modifications are required, and the new system is complex.
2. Because most of the energy contained in any steam exhausted to the condenser (a minimum flow for cooling the low-pressure turbine is always required) is discarded, this system is less efficient than a back-pressure conversion. However, the overall efficiency will never be less than the all-electric mode for which it was originally designed.
3. The cost of this conversion is usually considerably more than for a back-pressure conversion due to the complex control system required.

3.3 Selection Criteria

Selection of the recommended conversion required evaluation of each alternative with respect to a number of criteria:

Lowest Cost. The ideal system should have the lowest capital and operating cost. Lower operating cost is generally more important than lowest initial cost. In any system there is a limit beyond which the operating costs cannot be sufficiently lowered to repay the increased capital cost.

Reliability. The heat supply should be sufficiently reliable so that the utility management will have as much confidence in the cogeneration system as they currently have in the electrical supply system.

Operating Flexibility. The ability to satisfy heat and electricity demands by using different combinations of equipment increases overall reliability and also permits selecting the combination that results in the lowest operating cost.

Burn Coal in Preference to Oil or Gas. Coal, an abundant domestic resource, is less expensive than gas or oil. Federal energy policy encourages use of coal, whenever possible, to conserve scarce oil and gas.

Constraints on Converting Existing Units. Both mechanical and thermodynamic constraints must be considered. Mechanically, single-casing turbines are not amenable to condensing-tail conversion. Multiple-casing turbines may experience bearing alignment problems if converted to backpressure operation. Thermodynamic constraints include limitations on entrained energy in extraction lines, extraction limitations, and the effect of increased extraction on the pressure and flow to subsequent stages.

Available Space. Sufficient space must exist for large heat exchangers and other equipment. Adequate space around the new equipment must be availabe for maintenance. Large pipes are required, and a path must be available to route them. Use of these spaces must not block any access, or otherwise interfere with the plant operation.

Other Considerations. Is the existing equipment in satisfactory condition or will major repairs be required in addition to the modifications? Can the existing equipment be expected to perform reliably after repair and/or modification? Does the configuration of the existing equipment permit the mechanical modifications (e.g., are the crossover lines accessible)? Are the floors strong enough or can they be reinforced to support the new equipment? How can the new equipment be brought into the building and set in place (preferably with minimal disruption of current station operation)?

4. ASSESSMENT OF HIGH BRIDGE UNITS

4.1 Unit 3

4.1.1 General

Unit 3 was installed in 1942 and has a rated capacity of 50 MW(e) with a power factor of 0.8; it is capable of generating 62.5 MW(e) with maximum steam flow at a power factor of 1.0. Due to air quality regulations, the unit burns a mixture of high- and low-Btu coal rather than the high-Btu coal for which it was originally designed. The fuel change has reduced the unit to 42 MW(e) due to insufficient steam flow from boiler 9. In 1977, the unit availability was high with a heat rate of 13,071 kJ/kWh (12,389 Btu/kWh).

4.1.2 Physical condition

Turbine. In 1966 the steam turbine was modernized, extensively rebuilt, and the start-up mode changed to full-arc admission; thus, the turbine was restored to essentially new condition. In most respects the turbine is 12 years old rather than 36. Weak points with the turbine are the No. 1 bearing and the obsolete supervisory instrumentation. The bearing is not regarded as a serious detriment by either the station operating personnel or by the General Electric Company. The supervisory equipment is more significant when the turbine is operated to meet demand peak load (as it is now) than when used to supply the base load as will be required of the retrofitted turbine. Additionally, the retrofit will require control modifications which will eliminate some of the obsolete equipment.

The high-pressure rotor is forged at 1283 K (1850°F) of chromium-molybdenum-vanadium steel which was the standard material when this turbine was built. General Electric Company recommends replacement of this rotor with one produced from more modern material and manufacturing processes (at an estimated installed cost of $800,000). Because the proposed retrofit system for the High Bridge plant anticipates using unit 3 to supply the base load with the result that the rotor will be subjected to less severe stresses than at present, UE&C does not believe this expenditure necessary.

There is blade erosion in the low-pressure section. This is normal wear from steam moisture. However, the back-pressure conversion recommended by the manufacturer would require removal of all low-pressure blading, thus eliminating this maintenance item.

Complete turbine inspections were made in 1971, 1974, and 1975. No major problems were found, and the equipment condition appears to be stable.

Generator. The generator has been performing satisfactorily, with no indications of impending problems. The operating availability of the turbine-generator was 94.1% during 1977.

Condenser. The existing condenser is in satisfactory condition; however, the proposed conversion requires its removal.

Feedwater Heaters. The closed heaters have tube leaks which operating personnel cannot locate. However, this maintenance problem is not serious enough to preclude consideration of unit 3 for conversion.

There is no indication of any significant deaerator problems. Operating personnel of NSP report that the deaerator has been functioning properly, although it has not been inspected recently.

Boiler. At present, the High Bridge station is burning a mixture of 70% western low-sulfur coal [20.2 MJ/kg (8700 Btu/lb)] and 30% Illinois high-sulfur coal [24.4 MJ/kg (10,500 Btu/lb)] to comply with air pollution regulations. Because of the lower heating value of this blend compared to 100% Illinois coal for which the boiler was designed, maximum steaming rate is 50 to 57 kg/s (400,000 to 450,000 lb/h), which is about 75% of the boiler rating.

Because a cross-tie exists between boilers 9 and 10, both can be operated simultaneously to supply turbine 3 with its maximum 68.40 kg/s (540,000 lb/h) of steam. When unit 4 is not operating, this simultaneous operation will provide a surplus of steam production which can be used directly in a heat exchanger to provide additional DH capacity in an emergency. As part of the retrofit, UE&C recommends replacement of the superheater outlet header which has been a frequent source of leaks.

The Bailey combustion controls are obsolete by modern standards, and NSP operating personnel have noted that replacement parts are difficult to obtain. This has been confirmed by Bailey Meter Company. To continue operating this unit either as it is, or to convert to cogeneration, new (but not necessarily improved) controls will be required.

Boiler Feed Pumps. Boiler feed pump 31 drive motor was reported to be shaky. A failure of this motor will idle the pump until repair parts can be obtained. However, because of the reduced steam production of boilers 9 and 10, this is of no concern. Only three of the remaining four pumps are required to operate both boilers at their present maximum production.

Miscellaneous. The NSP operating personnel have noted that the existing precipitator will have to be upgraded to keep unit 3 in service for another 15 years. United Engineers & Constructors Inc., has not developed independent information concerning the precipitator.

Summary. Overall, unit 3 is in satisfactory mechanical condition and its useful life can be sufficiently extended by replacement and upgrading of critical equipment.

4.1.3 Feasibility of conversion

Conversion of the unit 3 turbine to back-pressure cogeneration is recommended. Only back-pressure conversion is considered because it is simpler, less expensive, and more efficient. With single-case machines like the unit 3 turbine, the crossover is an oddly shaped passage in the casing. To install a control valve in this passage for condensing-tail operation would require the design and production of a unique valve, which would be prohibitively expensive. General Electric has agreed that the proposed back-pressure conversion is feasible.

4.2 Unit 4

4.2.1 General

Unit 4 is a sister unit to unit 3 and, because of the fuel used, has also been rated down to 42 MW(e). However, unit 4 suffers from several problems not present in unit 3 and, because of these problems, unit availability was limited during 1977.

4.2.2 Physical condition

Turbine. The turbine was rebuilt in 1966 and, like unit 3, has obsolete supervisory instruments and a trouble-prone No. 1 bearing. Neither of these faults is regarded as serious.

However, there are serious problems with balance and alignment of the turbine rotor. The best achievable balance on turbine 4 still results in 3–5 mils vibration amplitude, which is the maximum acceptable. This is not conducive to equipment reliability. Compounding the balance problem is an alignment problem caused by nonuniform sinking of the generator foundation. This sinking began a few years ago, and the cause has never been determined, although there is evidence that the sinking may be associated with the recent construction of a stack. There has been no sinking lately, but there is insufficient information to confidently predict that the problem no longer exists.

The last-stage buckets have been machined off because of a failure (presumably from erosion). Turbine 4 has a newer technology high-pressure rotor than turbine 3; therefore, General Electric does not recommend replacement.

Complete turbine inspections were made in 1971 and 1976. No significant problems were found. The turbine-generator availability during 1977 was 73.4%.

Generator. Both unit 3 and unit 4 generators were built before or during World War II when copper was scarce. As a result, the field windings in both are of an aluminum alloy, although copper was used for the rotor. According to the generator manufacturer, the combination of aluminum and copper is not desirable. In fact, generator 4 did experience a failure in 1974. The generator was repaired and no further incidents have occurred; however, neither NSP operating personnel nor the local General Electric Company representative has confidence in the unit 4 generator.

Condenser. The unit 4 condenser is reported to be in good condition.

Feedwater Heaters. The unit 4 feedwater heaters are in the same condition as those of unit 3.

Boiler. The unit 4 boiler (10) has the same outlet-header problem as boiler 9; however, NSP operating personnel believe that the boiler-10 secondary superheater must also be replaced. No independent confirmation was available.

Summary. Overall, the condition of unit 4 is judged to be unfavorable for conversion.

4.2.3 Feasibility of conversion

Serious turbine-generator problems and insufficient boiler capacity (due to lower than design-Btu coal) to supply the full-load steam requirements of both turbines 3 and 4 prevent a recommendation to convert unit 4. Although unit 4 will not be retrofitted, boiler 10 should be kept in service to supplement the capacity of boiler 9.

4.3 Unit 5

4.3.1 General

Unit 5 was installed in 1956. Its rated capacity is 90,900 kW(e) at a power factor of 0.85. During 1977, the unit availability was high, and the heat rate was 11,127 kJ/kWh (10,537 Btu/kWh).

4.3.2 Physical condition

Turbine-Generator. Unit 5 turbine-generator appears to be in good condition. The only concern expressed by NSP operating personnel was about the future availability of parts and service. United Engineers & Constructors Inc. queried Allis-Chalmers about NSP's concern and was advised that no problems are foreseen until after the year 2000. The turbine-generator availability for 1977 was 94.5%.

The turbine was last overhauled in the spring of 1975. Allis-Chalmers was unable to provide any additional information about the condition of this equipment.

Boiler. No boiler problems are known, although NSP has budgeted money to modernize the boiler controls. This is independent of any conversion recommendation. The Power Production Operating Report indicates that during 1977, boiler 11 had an availability of 85.0%.

Balance of Plant. All other equipment was reported to be in good condition.

Summary. Overall, unit 5 is in good condition and has had good availability.

4.3.3 Feasibility of conversion

Conversion of unit 5 to a condensing-tail cogeneration unit is recommended. The type of conversion is dictated by the desired DH water temperature, by the desire to minimize lost electrical capability during the summer, and because bearing alignment problems are likely when large turbines are retrofitted for back-pressure operation. Allis-Chalmers has confirmed the feasibility of this conversion.

4.4 Unit 6

4.4.1 General

Unit 6 was installed in 1959. Its rated capacity is 156,250 kW at a power factor of 0.85. During 1977, the unit availability was 92.2% and the heat rate was 10,759 kJ/kWh (10,188 Btu/kWh).

4.4.2 Physical condition

Turbine-generator. Unit 6 turbine-generator was completely overhauled in the beginning of 1978 and is in good condition. Thermocouples for detecting water leaks were installed during the overhaul. The only problem appears to be erosion of the inlet section of the high-pressure turbine, possibly due to exfoliation in the boiler superheater and/or main steam leads. The generator was reported in good condition. During 1977 the unit 6 turbine-generator had an availability of 98.6%.

Boiler. The boiler and ancillary equipment were reported in good condition. This is confirmed by the boiler availability of 93.8% in 1977 and by the local Babcock and Wilcox representative.

Balance of Plant. All other major equipment — including condenser, feedwater heaters, and pumps — was reported in good condition, and UE&C's observations support this opinion.

Summary. Overall, unit 6 appears to be in good condition.

4.4.3 Feasibility of conversion

Conversion of unit 6 to a condensing-tail cogeneration unit is recommended. The type of conversion is dictated by the same considerations as for unit 5. General Electric Company has confirmed the feasibility of this conversion.

5. CONCEPTS

5.1 Concepts Recommended

5.1.1 Design concept 1

It is recommended that unit 3 be retrofitted for back-pressure operation and that units 5 and 6 be retrofitted for condensing-tail operation. An auxiliary DH heat exchanger should be installed to take advantage of steam available when turbine 4 is not operating.

In the recommended DH water cycle in the High Bridge station (Fig. 5.1), the return water (cold) enters the pump suction before any heating because this will be the point of maximum available net positive suction head. Pump discharge is preheated in exchanger 3, which will replace the existing condenser. Steam for exchanger 3 is the exhaust steam from turbine 3 (converted to back-pressure operation). The condensed steam will be returned to the feedwater cycle(s).

Unit 3, as base load, will carry the continuous thermal demand and as much of the variable demand as possible. Also, as base load, unit 3 will be in maximum use, and, because electrical production is directly proportional to thermal load in a back-pressure turbine, loss of electrical capability will be minimized.

Exchangers 5 and 6 will each further heat part of the DH water because they are piped in parallel. The final temperature, which depends on the outdoor temperature, will be controlled automatically by varying the steam supply from the turbines.

Steam for exchanger 5 will be obtained by adding an extraction connection to the crossover between the intermediate- and low-pressure turbines. To control the pressure ratio across the intermediate-pressure turbine and to control the steam supply to the DH heat exchanger, a pressure-control valve will be installed in each of the crossover lines, and a temperature-control valve will be installed in the extraction line. The condensed steam from exchanger 5 is returned to the feedwater cycle via the deaerator.

Unit 6 is modified similarly to unit 5 and provides the steam source for DH heat exchanger 6. In the summer, or whenever the entire heat load can be supplied by unit 3, units 5 and 6 can be operated in the electric-only mode to generate the same amount of electricity as before the conversion. The condensing-tail conversion is also ideal for meeting peak demands for heat, since the heat load can be varied from essentially zero to maximum. Exchanger 3A will be supplied with steam from boilers 9 and 10 if needed because of an outage of other heat source equipment.

Since unit 3 provides sufficient base-load capacity, unit 4 will remain for electrical generation only. The combination of unit 3 (back-pressure) and units 5 and 6 (condensing-tail) provides a system of considerable flexibility which, under normal circumstances, can supply the entire heat load without recourse to heat-only boilers. Installation of exchanger 3A provides an even more reliable system.

5.1.2 Design concept 2

Since profitability, and therefore feasibility, of the proposed DH system depends upon achieving maximum penetration of the available market (to minimize transmission and distribution costs) and upon maximizing sales of the available heat, various ways to improve these factors were investigated.

The design as developed and described in this report is based upon the assumptions that the DH system will serve heating loads exclusively and that all subscribers will modify their existing heating systems as required to use the DH water with a varying supply temperature (Fig. 5.2).

Many buildings in the market area are heated with low-pressure steam. Converting these buildings to the proposed hot water DH system will necessitate a complete replacement of the existing building heating system as well as installation of a new heat exchanger. To reduce the conversion cost for these buildings and thereby entice the owners to subscribe, the DH supply temperature could be kept at 422 K (300°F), throughout the heating season which permits generation of low-pressure steam directly

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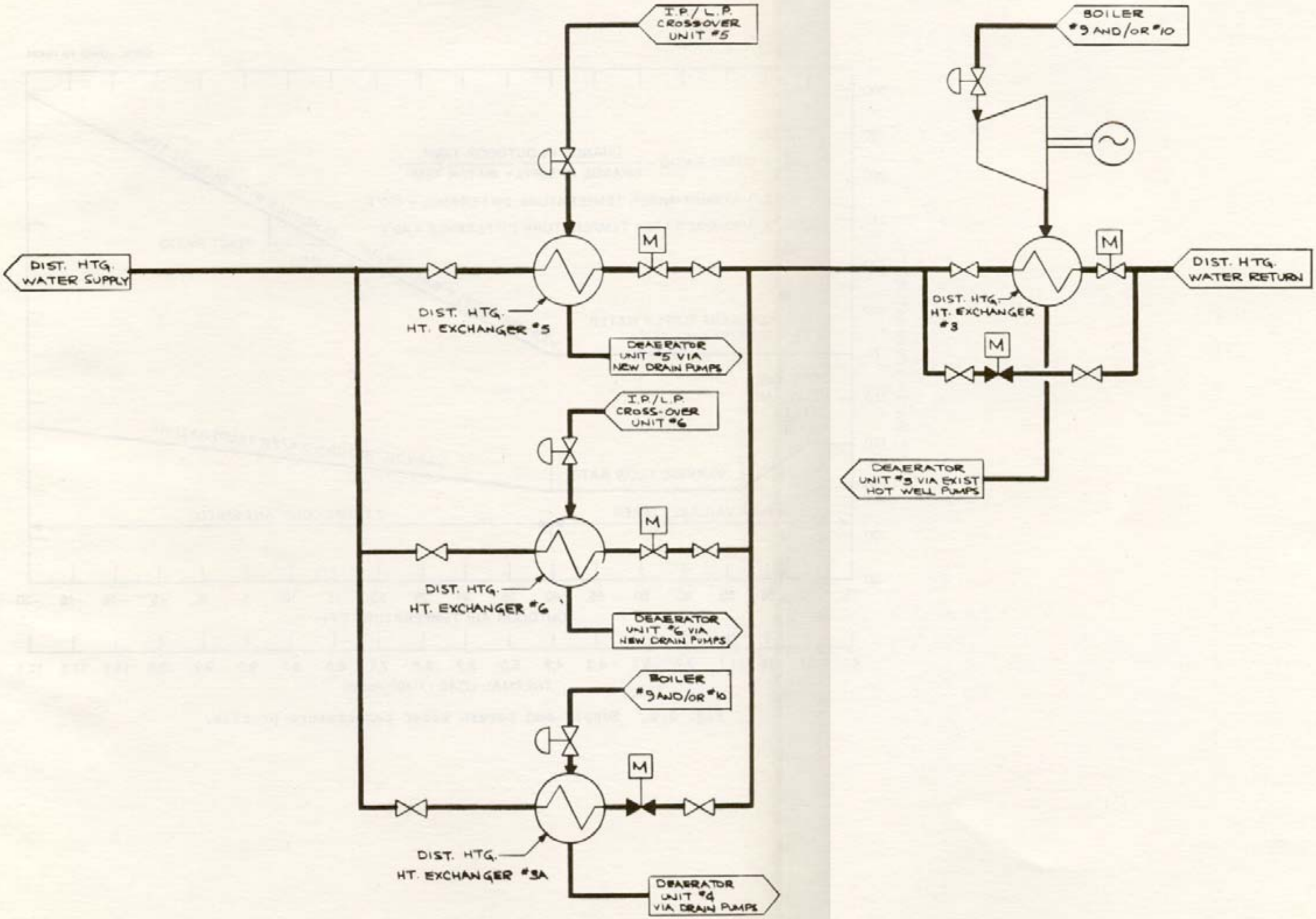

Fig. 5.1. Water flow for High Bridge cogeneration retrofit.

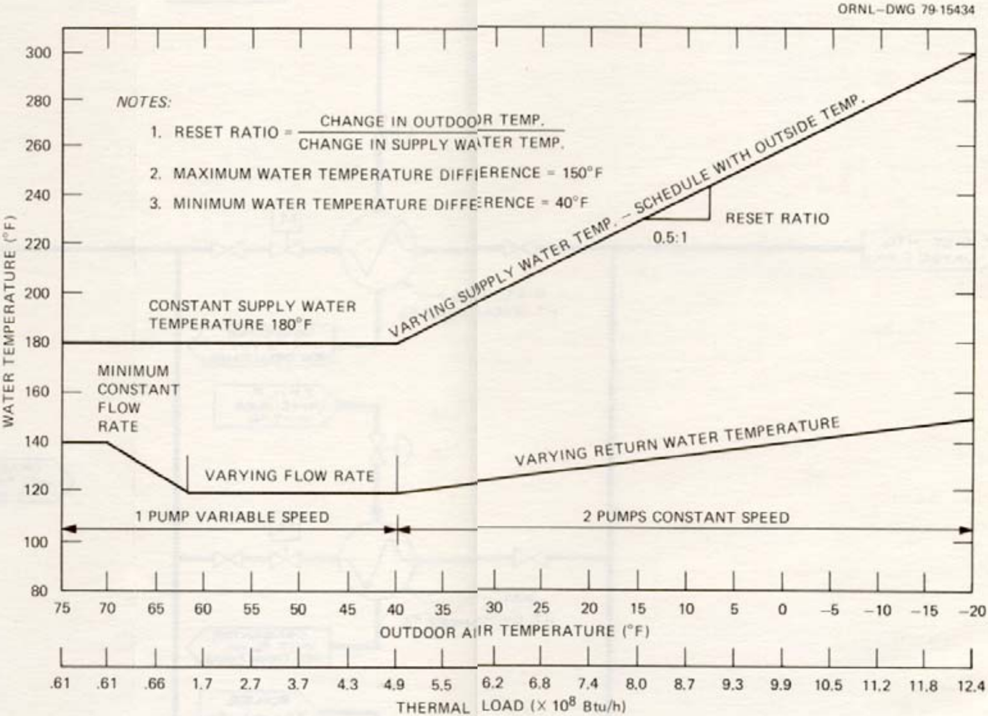

Fig. 5.2. Supply and return water temperature profile.

in the heat exchanger, thus eliminating the need to replace an existing steam heating system.

Modifying the DH system to keep the supply temperature at 422 K (300°F) also permits serving summer, and even winter, air conditioning loads for those customers with absorption air conditioning. This service increases summer use with a corresponding increase in total annual heat sales.

5.2 Additional Concept Modifications Recommended for Consideration

A review of the completed design of concept 1 identified the following modifications that may improve the system's operation or decrease the cost.

1. Retrofit units 5 and 6 for condensing-tail operation and use the Third Street plant for backup and summer load.
2. Retrofit units 5 and 6 for condensing-tail operation, and either unit 3 or 4 for back-pressure operation. Use the Third Street plant for backup in lieu of exchanger 3A.
3. Use the design concept as specified, except that DH heat exchangers 5 and 6 would each be capable of accepting 100% of the DH water flow. These exchangers are now designed to each accept only as much water flow as can be heated to 422 K (300°F) with the amount of steam available to each.
4. Revise the recommended sequence of construction including the possible use of oil-fired boilers to meet peak-load demands.

5.3 Concepts Considered

Five systems concepts were briefly considered and then rejected:

1. Retrofit units 3, 4, 5, and 6 for back-pressure operation. Lost summertime electrical capacity from units 5 and 6 was considered unacceptable. In addition, General Electric Company later advised that they did not consider back-pressure conversion of turbine 6 to be feasible.

2. Retrofit units 3, 4, 5, and 6 for condensing-tail operation. Because units 3 and 4 are single-case machines, installation of the necessary valve in the crossover is not feasible.

3. Retrofit units 3 and 4 for back-pressure operation, retrofit units 5 and 6 for condensing-tail operation, and install heat-only boiler(s) for peaking and backup. Boilers 9 and 10 are only capable of 75-85% of their original steam production due to use of low-Btu coal. Therefore, there is insufficient steam to supply both units 3 and 4 at full capacity. Also, the forecast DH load through the year 2000 cannot effectively use both units to supply the base load.

4. Retrofit units 5 and 6 for condensing-tail operation and unit 3 for back-pressure operation. Install heat-only boiler(s) for backup. Existing boilers at the Third Street station could be used for backup with less investment than required for new boilers.

5. Retrofit units 5 and 6 for condensing-tail operation and unit 3 for back-pressure operation. Install heat exchangers at Third Street station for backup. If turbine 4 is idle, boilers 9 and 10 would have excess steam-generating capacity. By installing an auxiliary exchanger at the High Bridge plant to use this excess steam if required, backup could be provided at about the cost of installing an exchanger at the Third Street plant. Considerable savings could be realized in operating costs because (1) the Third Street plant could then be closed when steam customers were switched to water and (2) the High Bridge plant has a lower fuel cost than the Third Street plant.

6. STATION MODIFICATIONS

6.1 Description

6.1.1 General

Units 3, 5, and 6 will be converted to cogeneration. Unit 4 turbine-generator will not be used, but boiler 10 and the feedwater heater string will be used. Auxiliary heat exchanger 3A, supplied with steam directly from boilers 9 and 10, will provide backup capacity.

Boilers 9 and 10 will operate in parallel to supply maximum steam to turbine 3. Neither boiler alone can provide all of the steam required by turbine 3 with the present lower Btu fuel. The necessary cross-connections required to operate the boilers in parallel already exist.

Normally, boilers 9 and 10 will produce the maximum steam required for turbine 3, with the excess available for turbine 4. If required by equipment outages, steam [up to a maximum of 50–63 kg/s (400,000–500,000 lb/h)] can be produced to use in DH heat exchanger 3A. Drains from exchanger 3A are returned to the boiler via the unit 4 deaerator and high-pressure feedwater heaters. Pumps will be added to drain exchanger 3A.

Unit 3 turbine will be converted to operate at a back pressure of 76–103 kPa (11–15 psia), and the existing condenser will be replaced with DH heat exchanger 3. Condensate will be returned to the boiler through the existing condensate/boiler feed system, except that the low-pressure feedwater heater will be bypassed.

Unit 5 turbine will be retrofitted for condensing-tail operation and a new heat exchanger installed in the unit 2 area to heat the DH water using the crossover-extraction steam. Drain pumps will be added to return the condensed steam to the boiler feedwater cycle at the deaerator.

Unit 6 will be retrofitted similarly to unit 5 (Fig. 5.1).

The new heat exchangers and other equipment installed will require that two operating-floor openings along the north wall of the turbine hall be covered with grating. Three operating-floor openings along the south wall of the turbine hall will remain clear as requested by station operating personnel.

Drain pumps and other equipment installed in the basement of units 1 and 2 will require foundations. In all cases, 15.24-cm-thick (6-in.) concrete pads will be adequate.

6.1.2 Unit 3

The back-pressure modification of turbine 3 will be done by removal of all of the low-pressure blading (stages 18–21). General Electric Company recommends that, in lieu of machining the blades from the low-pressure rotor, the entire low-pressure rotor be replaced with a spool piece.

The increased pressure ratio across the 17th stage may require replacement of the bucket-and-diaphragm combination with one designed for the increased stress.

General Electric Company recommends that the high-pressure rotor be replaced with a new one produced with a more modern heat treatment (Sect. 4.1.2). This recommendation is independent of any conversion. The cogeneration operation will subject the rotor to less severe duty than at present. Instead, UE&C recommends a periodic boresonic inspection (ultrasonic testing) of the existing rotor (with repairs, if indicated).

A turbine governor and back-pressure controller with control-transfer package will have to be added (Sect. 8.2). Because of the increased condenser pressure, a larger seal, steam regulator will be required.

General Electric Company has indicated that it may be necessary to reinforce the existing low-pressure casing, but a detailed study is required to make a definite determination.

The 75–103 kPa (11–15 psia) back pressure results in condensate at 365–374 K (197–213°F) [compared with 307 K (92°F) at the current 5 kPa (1.5-in.-HgA) exhaust pressure]. This condensate will be too hot to cool the hydrogen cooler, so the hydrogen cooler must be removed from the condensate system and an alternate source of cooling water provided. Adequate water should be available from the station service-water system.

The existing low-pressure feedwater heater will serve no useful purpose; therefore, it will be bypassed (and the extraction lines blanked off and trapped).

Without the low-pressure heater in service, there will be no use for the heater drain pumps, so they will be simply left in place, but disconnected, and all isolation valves closed.

The existing condenser is unsuitable for use with the converted unit, because the tube sheets and water boxes cannot withstand the 2169-kPa (300-psig) DH water pressure, and reinforcement is not practical. Accordingly, the existing condenser must be removed and replaced with a new heat exchanger.

The new exchanger will have a dome-type steam inlet on top of the shell, which will be designed to mate to the existing exhaust opening. Probably the existing condenser supports, hot-well-level controls, conductivity-monitoring equipment, and existing hot-well pumps will be usable with the new exchanger.

Because the turbine-exhaust steam will be condensed in the new heat exchanger and the heat absorbed by the DH water, there will be no use for the circulating water pumps. These can be removed or disconnected in place, with the decision being based upon considerations of any interferences with installation of the new exchanger, usefulness in another station, scrap value, and costs of removal and covering the remaining floor opening.

The DH water piping consists of 76.2-cm (30-in.) lines to and from exchanger 3 and a 60.96-cm (24-in.) bypass. The inlet valve and bypass valve are motorized with position indicators and, as such, require installation of appropriate cable and motor starters.

Using unit 3 for DH will extend the unit's service life because it will supply the base load. With the extended life, miscellaneous additional items of maintenance and/or parts replacement, which could have been ignored, will be required. For example, new (but not necessarily improved) boiler controls will be required, because repair parts for the existing equipment may not be available.

6.1.3 Unit 4

Since the system proposed can use only one back-pressure turbine for the base load and since unit 4 has not been considered for conversion because of alignment problems, boiler 10 will be kept in service to supplement the capacity and improve the reliability of boiler 9.

Excess steam from boilers 9 and 10 will be used in DH heat exchanger 3A, if required. The resulting condensate will be returned to the boiler(s) through the unit 4 deaerator and high-pressure feedwater heaters. To assure proper boiler operation and steam temperature, it will probably be necessary for the condensate to enter the economizer at the same temperature it currently does. If no extraction steam is available from turbine 4, boiler steam must be supplied to the heaters and deaerator through temperature and pressure control valves (Fig. 6.1). All of the steam for exchanger 3A and the feedwater heaters is obtained from a branch added to the boilers 9 and 10 steam-side cross-tie.

The pressures and branch configurations were selected from considerations of heater performance, required line sizes, severity of control-valve duty, and minimal size and number of safety valves required. Each of the safety valves requires a vent to the outdoors. In most cases these vents will be routed along column row 4 and exit through the turbine-hall roof.

The branch connection requires a motorized shut-off valve to permit isolation for maintenance and also requires appropriate expansion loops. Drain pumps and level controls are required for exchanger 3A. The drain pumps and motorized valves require motor starters.

As with unit 3, appropriate repairs should be made to all usable equipment. Most notable is a new secondary superheater for boiler 10.

6.1.4 Unit 5

Turbine 5 will be retrofitted to operate as a condensing-tail cogeneration turbine. This requires installation of a pressure-control valve in each of the two intermediate-pressure to low-pressure turbine crossover lines, the addition of an extraction connection to the crossover, and major control modifications.

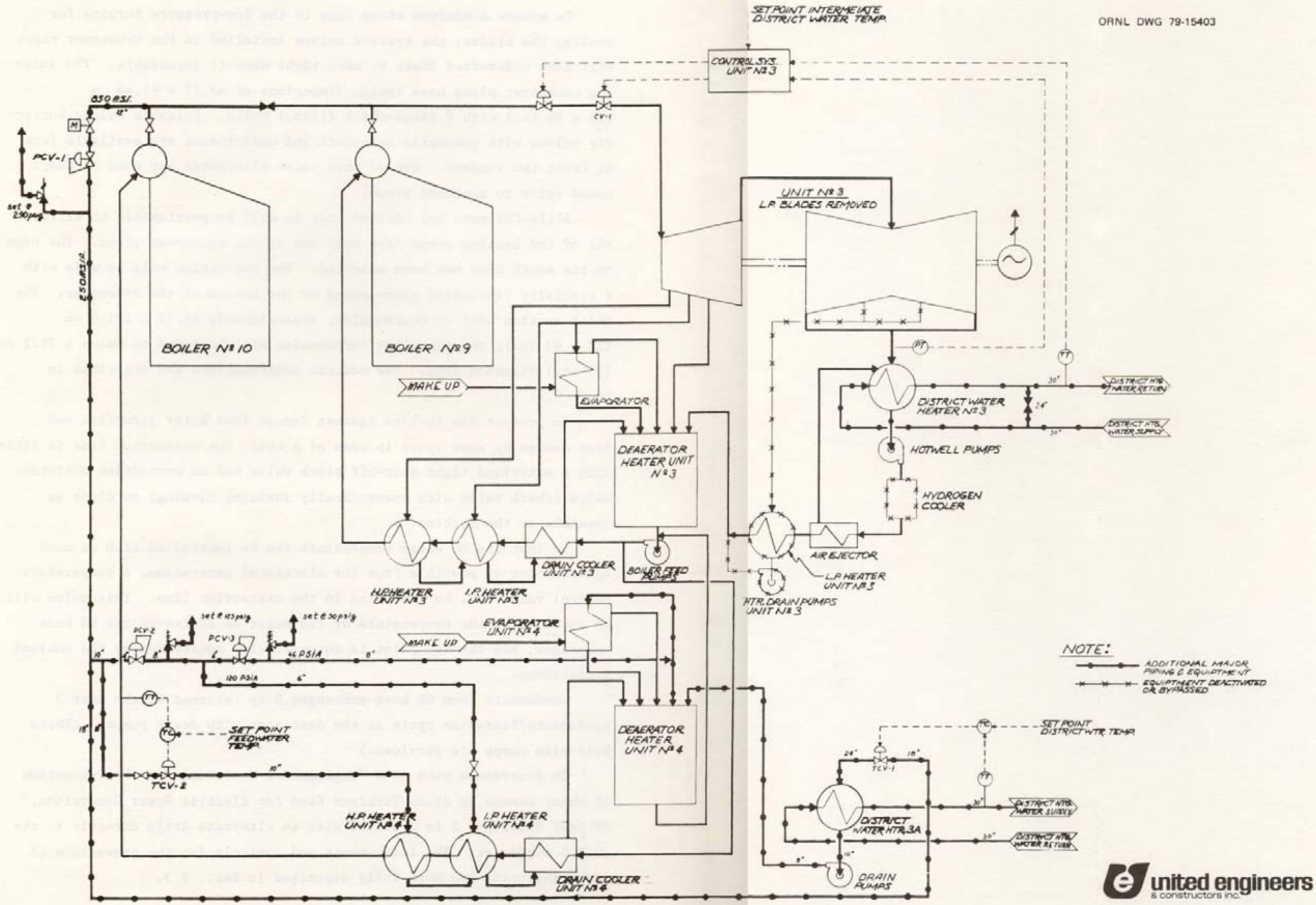

Fig. 6.1. Conversion to district heating of High Bridge units 3 and 4.

To ensure a minimum steam flow to the low-pressure turbine for cooling the blades, the control valves installed in the crossover pipes will have undersized disks to make tight shutoff impossible. The existing crossover pipes have inside dimensions of 45.77 × 91.44 cm (18 × 36 in.) with 2.54-cm-thick (1-in.) walls. Suitable oblong butterfly valves with pneumatic actuators and positioners are available from at least two vendors. Use of this valve eliminates any need to adapt a round valve to nonround pipes.

Allis-Chalmers has advised that it will be permissible to extract all of the heating steam from only one of the crossover pipes. The pipe on the south side has been selected. The connection will be made with a specially fabricated elbow added to the bottom of the crossover. The inlet section will be rectangular, approximately 45.72 × 101.6 cm (18 × 40 in.), and the elbow termination will be round to match a 76.2 cm (30 in.) standard pipe. The control modifications are described in Sect. 9.1.

To protect the turbine against damage from water induction and from damage by over speed in case of a trip, the extraction line is fitted with a motorized tight shut-off block valve and an extraction nonreturn valve (check valve with pneumatically assisted closing) as close as possible to the turbine.

So that the DH water temperature can be controlled with as much independence as possible from the electrical generation, a temperature-control valve will be installed in the extraction line. This valve will be actuated by the temperature of the water as it leaves the DH heat exchanger, and the set point is automatically controlled by the ambient temperature.

Condensate from DH heat exchanger 5 is returned to the unit 5 condensate/feedwater cycle at the deaerator with drain pumps. (Three half-size pumps are provided.)

In accordance with ASME "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation," DH heat exchanger 5 is provided with an alternate drain directly to the unit 5 condenser. The instruments and controls for the prevention of water induction are more fully described in Sect. 8.3.

To protect the condensate system from contamination caused by heat-exchanger leaks, the normal drain is provided with conductivity monitoring and an automatic drain to a waste discharge, if the conductivity is excessive.

During periods of maximum extraction for DH, condensate flow from the condenser will be insufficient to cool the hydrogen cooler and air-ejector condenser. To ensure an adequate flow of condensate under these conditions, condensate will be recirculated from downstream of the air-ejector condenser back to the main condenser. The recirculation will be controlled automatically by a temperature-control valve. This control permits the condensate flow through the hydrogen cooler and air-ejector condenser to always be adequate without adversely affecting the hot-well level.

6.1.5 Unit 6

Turbine 6 will be retrofitted for condensing-tail cogeneration similar to turbine 5. The only differences are that the two crossover pipes are round; therefore, these pipes will be fitted with standard (except for the undersized disc) round butterfly control valves, and the new extraction connection must be added to both crossover pipes by replacing the elbows at the exit of the intermediate-pressure turbine with tees. The two upward-facing tee stubs will be joined with a 91.49-cm (36-in.) header which becomes the extraction pipe. The remaining modifications to unit 6 will be identical to those described for unit 5.

6.2 Arrangement

The proposed equipment arrangement (Figs. 6.2–6.4) takes into consideration available space, equipment maintenance requirements, station operating requirements, functional performance of the individual items of equipment, and ease of construction.

The DH heat exchanger 3 is located underneath the turbine 3 exhaust after the existing condenser is removed. This is the most convenient

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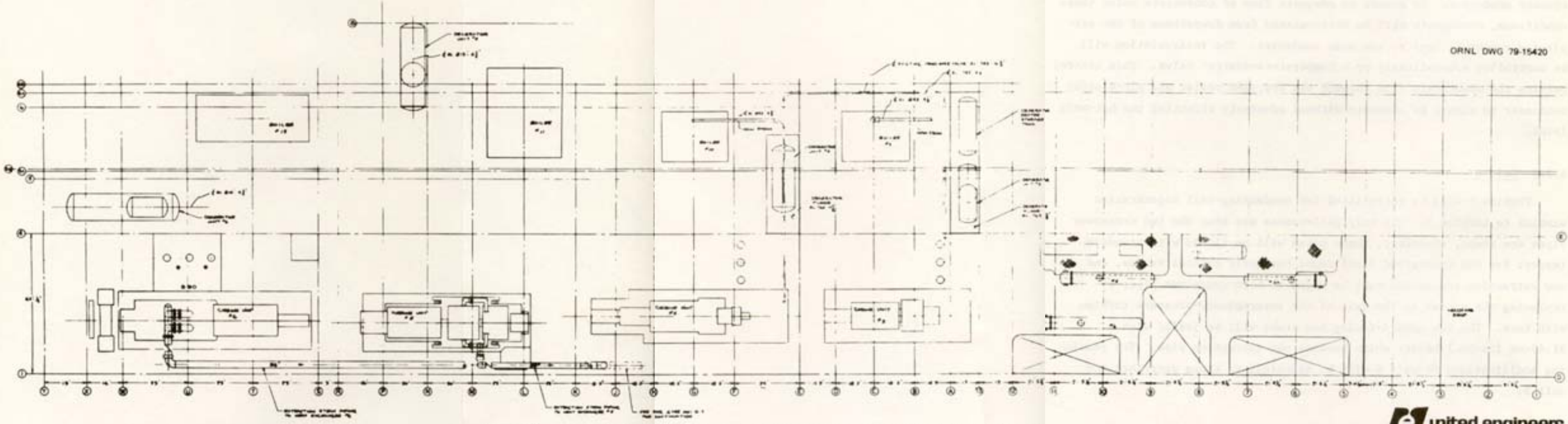

Fig. 6.2. General arrangement of the district heating equipment in the High Bridge Generating Station (operating floor).

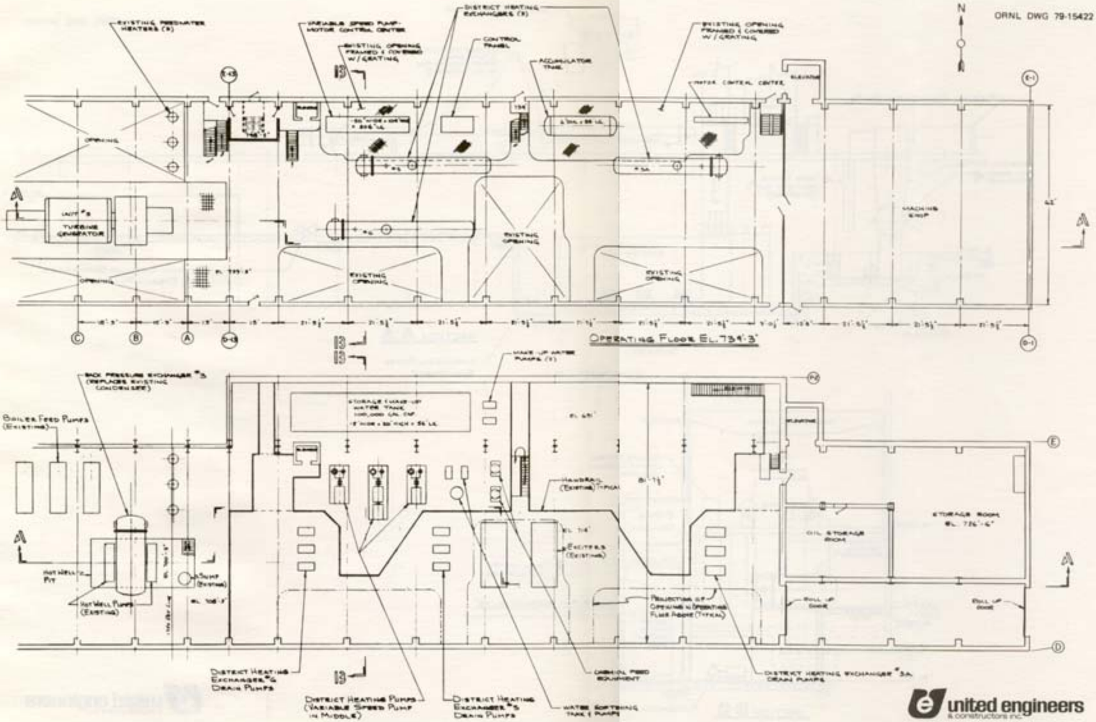

Fig. 6.3. General arrangement of the district heating equipment in the High Bridge Generating Station (basement floor).

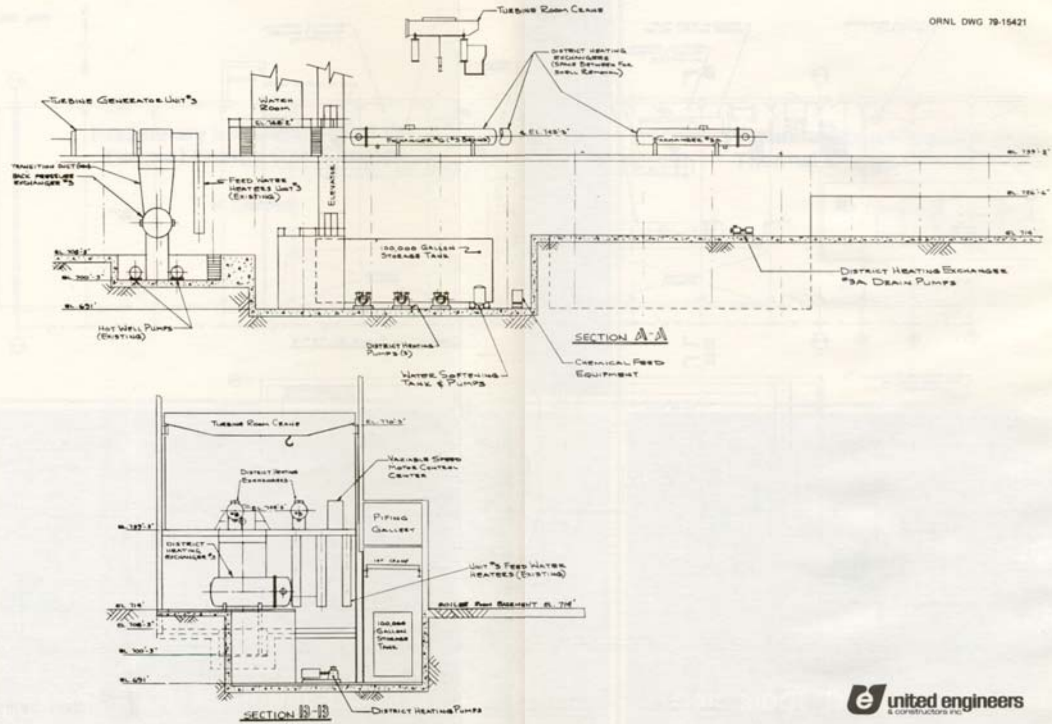

Fig. 6.4. Cross-sectional view of the district heating equipment in the High Bridge Generating Station.

location considering steam ducting and condensate piping. A four-pass exchanger was chosen so that the overall length would be no greater than the existing condenser, which assures adequate space for tube removal.

The DH heat exchangers 5, 6, and 3A are located on the operating floor in the area of retired units 1 and 2. The spacing permits shell removal for maintenance as well as sufficient space to walk around them. By being on the operating floor, maximum net positive suction head is provided for the drain pumps located directly beneath in the basement. Because the operating floor formerly supported two turbine generators and provided a disassembly and laydown area, it is expected that minimal (if any) reinforcing will be required to support the three DH heat exchangers.

In general, as much of the new piping as possible was kept below the operating floor. This location minimizes obstructions to loads being carried by the turbine-room crane. Even more important is ease of supporting these new pipes, especially the large steam and water pipes.

The notable exception is the 76- and 91-cm (30- and 36-in.) extraction-steam piping from turbines 5 and 6 to DH heat exchangers 5 and 6. Obstructions beneath the operating floor preclude under-the-floor routing so these pipes are positioned against the south wall of the turbine hall above the tops of doors and below the crane. To present minimal obstructions for the crane, these pipes will be supported by a ladder-type frame fastened to the wall. These pipes drop beneath the floor in the vicinity of unit 4, beyond the obstructions, and then come above again to enter the DH heat exchangers.

Although the piping is below the operating floor, power-actuated valves are located above the floor for visibility and ease of maintenance. Manually operated valves are all accessible for operation, although in some cases a hand chain may be required.

Piping is shown on Figs. 6.5–6.9. All pumps, both heat exchanger drain pumps and the main DH-system circulating pumps, are in the basement so vibration problems will be reduced. Foundation work is also minimized, since these pumps can be placed on concrete pads dowelled to the existing floor.

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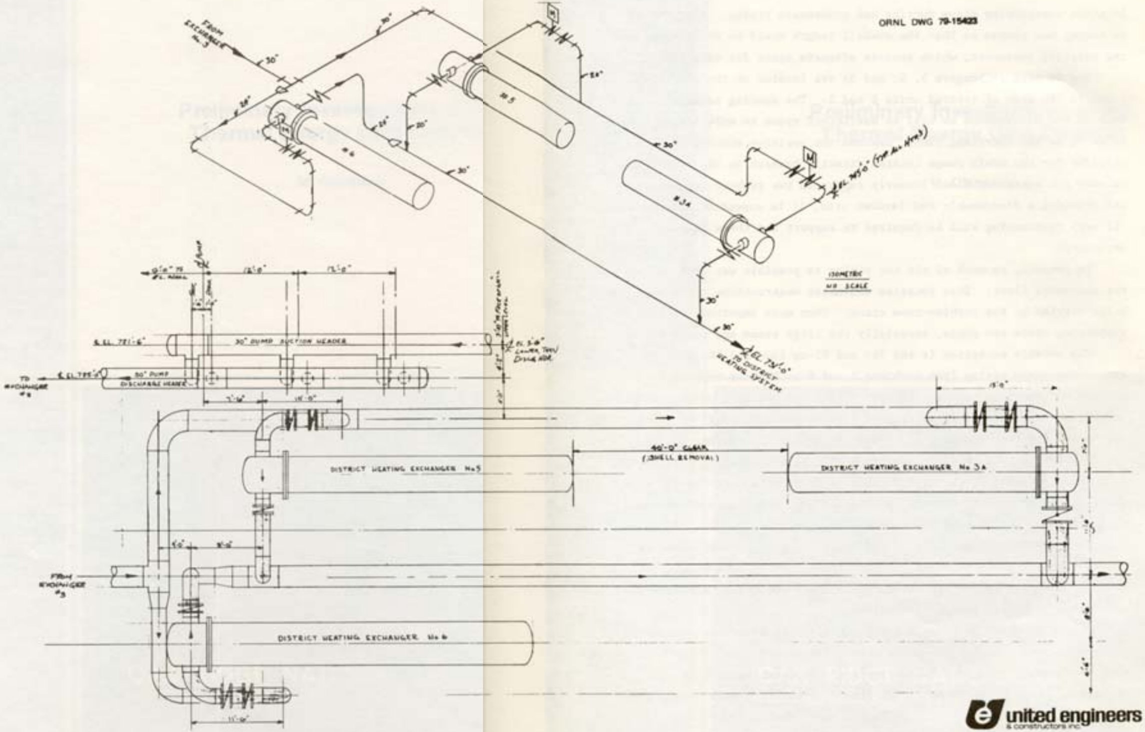

Fig. 6.5. Water piping at district heating heat exchangers in the High Bridge Generating Station.

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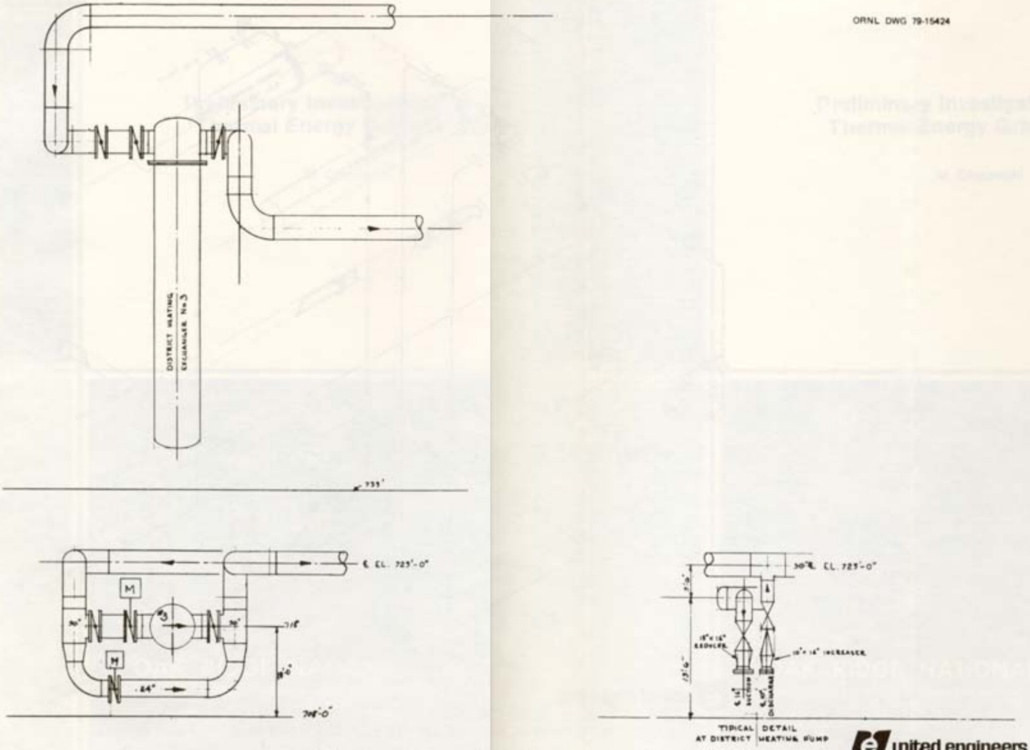

Fig. 6.6. Water piping at district heating heat exchanger 3.

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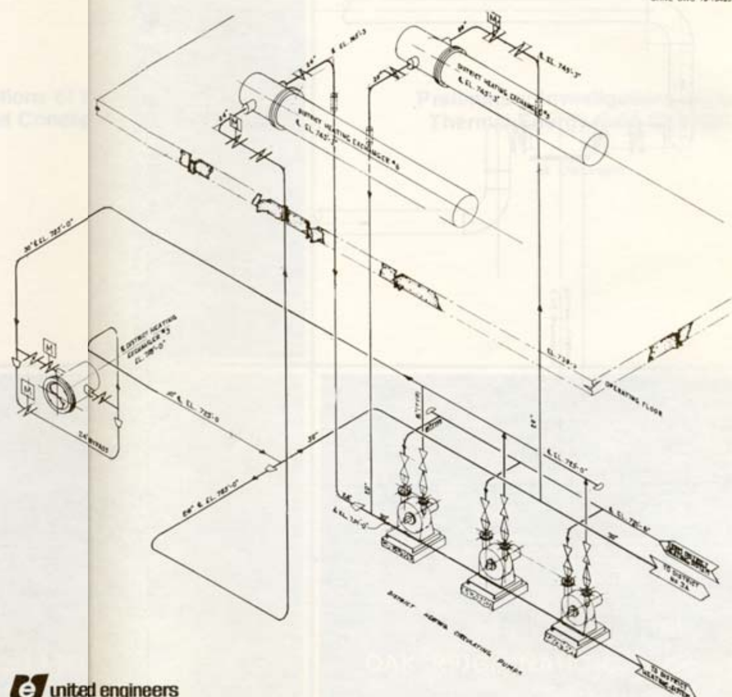

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Fig. 6.7. District heating water piping in the High Bridge Generating Station.

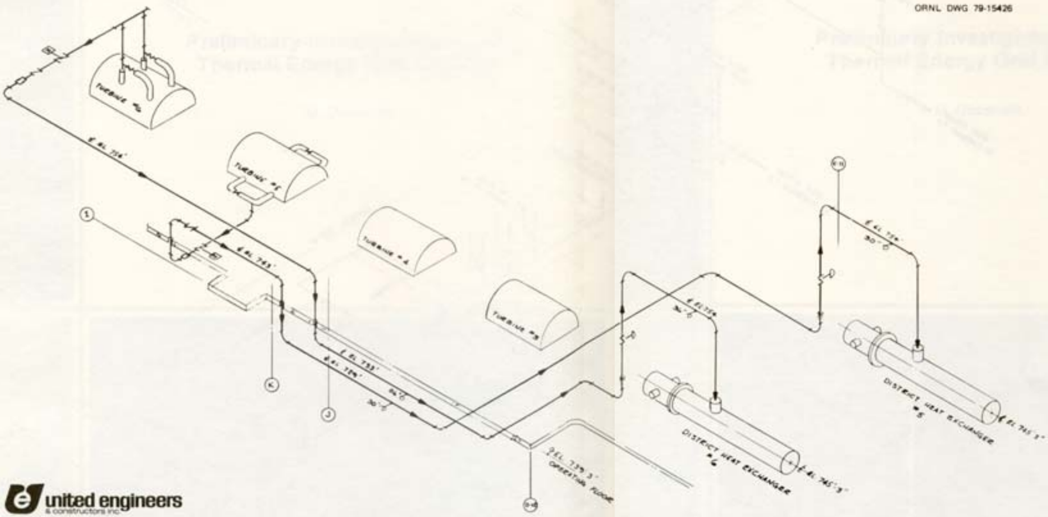

Fig. 6.8. District heating extraction steam piping in the High Bridge Generating Station.

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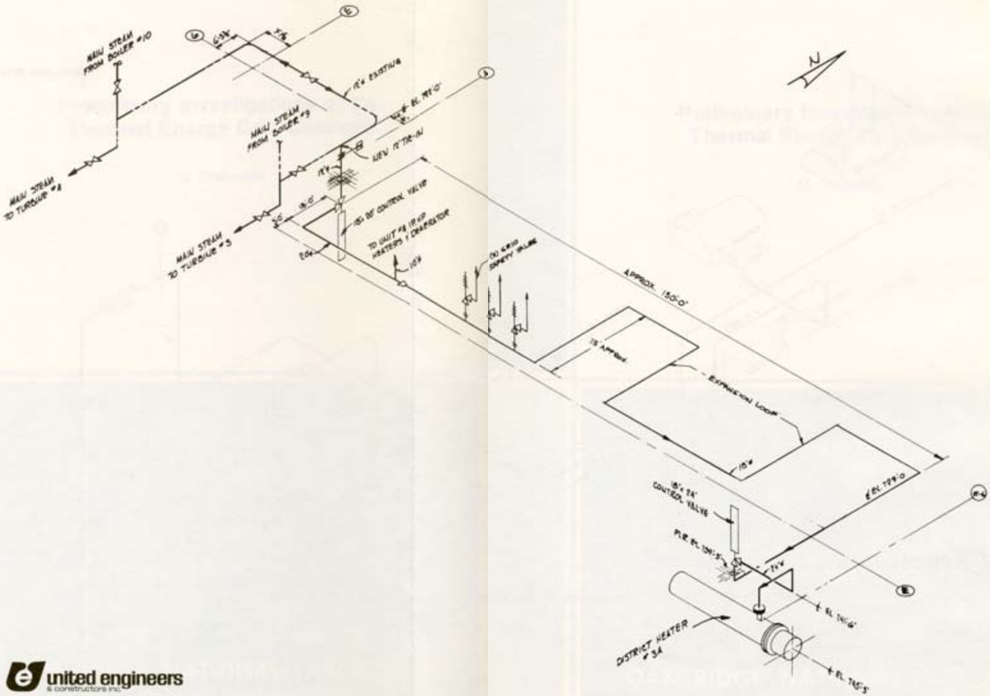

Fig. 6.9. Steam piping to district heating heat exchanger 3A in the High Bridge Generating Station.

The main steam line to heat exchanger 3A is routed over the unit 1 and 2 circulating-pump pit at elevation 222 m (729 ft). Support is by the turbine-hall columns, and adequate space exists northward for expansion loops.

Safety valves on this pipe can be vented vertically up along the south side of the pipe gallery, and, once above the turbine room crane elevation, the vent pipe can cross into the turbine hall and exit through the turbine-hall roof, which is the lowest roof.

The 379-m^3 (100,000-gal.) storage and make-up tank is located in the unit 5 circulating pump kit. By locating this tank indoors, no freeze protection is required. The chosen location is not expected to require any preparation to support the tank. Because a bridge crane exists above the pit, the tank can be erected in place. A rectangular tank is required to fit the available space.

7. SYSTEM DESCRIPTION

7.1 System Design Characteristics

Figure 7.1 illustrates the DH water system and the simplified controls. The incoming DH water first enters DH heat exchanger 3 where it is heated to an intermediate temperature of approximately 361 K (190°F). The set point for this temperature can be adjusted by the operator by means of a manual loading station. Low-pressure exhaust steam from unit 3, which operates as a back-pressure turbine, is the heat source. The control system for unit 3 automatically admits steam into the unit 3 turbine, so as to maintain the proper low-pressure steam flow into exchanger 3.

The DH water is subsequently piped to parallel DH heat exchangers 3A, 5, and 6. At the outlet of this parallel equipment arrangement, the DH water reaches the desired supply temperature. The set point for this temperature is determined by the dry-bulb temperature of the outside air (Fig. 5.2). The outlet temperatures of exchangers 3A, 5, and 6 are measured separately. These temperature measurements control the amount of steam admitted into the exchangers. Control valves at the inlet of exchangers 5 and 6 admit the steam required to keep the desired water temperature at the outlets. The steam to exchangers 5 and 6 is extracted from the intermediate-pressure–low-pressure crossover points of units 5 and 6. Steam to exchanger 3A is supplied through pressure-reducing and control valves from boilers 9 or 10, only when cogenerating units are not available for service.

District heating heat exchanger 3A is designed for the full DH water flow. Heat exchangers 5 and 6 are each designed for partial DH water flow. Together, they are capable of full DH water flow. The motor-operated valves at the inlets permit the operator to shut off the flow of water when any one of these exchangers is out of service. Also, these motor-operated valves permit the operator to proportion the waterflow to exchangers 3A, 5, and 6 when more than one is in service.

The amount of steam condensed in a DH heat exchanger is determined by the water flow rate and the inlet-outlet temperature difference of the water.

During operation, these are identical for exchangers 3A, 5, and 6. Thus, the ratio of DH water flowing through heaters 3A or 5 or 6 determines, during normal operation, the amount of steam condensed in each.

The differential pressure across DH heat exchangers 3A, 5, and 6 is measured. Interlocks prevent the closing of the motor-operated valves in the water circuit of DH heat exchangers 3A, 5, and 6, if the pressure drop across these exchangers reaches an unacceptably high value. This feature prevents water hammer in case the operator inadvertently restricts the water flow too severely. Also, a high-pressure drop across the exchangers sounds an alarm in the control room.

District heating heat exchanger 3A can be used during the summer months, when the heating load is low, or this heat exchanger can be used for supplemental heating when sufficient cogeneration units are not available because of equipment outage. Because cogenerating units provide significant fuel-cost savings, exchanger 3A is only used to supply heat when sufficient cogeneration units are not available to satisfy an existing heat demand.

7.2 Operational Flexibility

After completion of the design and cost estimates of the system (Fig. 7.1), it became evident that greater operating flexibility could be obtained by changing the concept. In the original design (Fig. 7.1), it is necessary to divide the water flow through exchangers 5 and 6, thus requiring operation of turbines 5 and 6 in the cogeneration mode during much of the heating season. By designing each of the DH heat exchangers to carry 100% of the DH water flow, greater operating flexibility can be obtained. In this operational concept it is no longer necessary to divide the DH water flow. Therefore, flow to either exchanger 5 or 6 can be shut off, and the turbine supplying steam to that exchanger can operate in the electric-generation mode.

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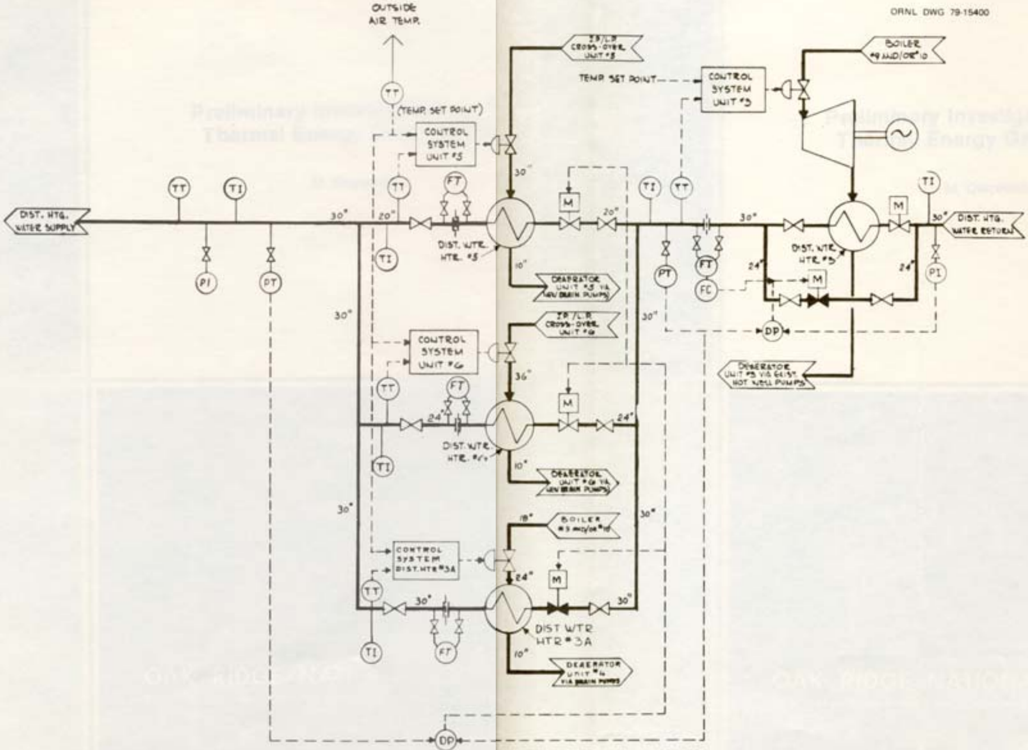

Fig. 7.1. Simplified controls for district heating water system.

8. INSTRUMENTATION AND CONTROL SYSTEMS

8.1 Turbine-Generator Control System for Units 5 and 6

8.1.1 Introduction

The mode of operation of a conventional condensing turbine is such that the turbine can be modified for condensing-tail operation.

The speed controller regulates turbine speed by varying the steam flow. This controller is used on conventional condensing units for start up, initial loading of the turbine, and for shut down of the unit. The load controller is used to control the turbine over the normal load range from approximately 20 to 100%. Turbine loading is controlled by the turbine throttle valve which, in case of an increased electrical demand, admits additional steam into the turbine as required to maintain turbine speed and, thus, the system frequency. The load controller allows the setting of loading rates (maximum allowable rates of change during load increase), manual load limit set points (maximum-minimum allowable load), interface to load-dispatch signal (communications with central dispatching system), and load runbacks (maximum allowable rate-of-change during load decrease).

With conventional condensing turbines, the loading rates and limits are determined by the electric-generation capability of the turbine-generator. After converting a condensing turbine to condensing-tail operation, the loading rates and limits are determined by two factors — electric-generation demand and steam demand for district water heating.

8.1.2 Control modes for turbine with condensing tail

To meet the different load requirements, it is possible, after converting the turbine to condensing-tail operation, to operate each turbine-generator unit in either of the control modes — electric generation only or cogeneration.

The change from one control mode to the other is done by a transfer switch located on the turbine control panel. The motor-operated shut-off valve which admits the steam to the DH heat exchanger is fully closed when the turbine-generator operates in the electric generation mode (Figs. 8.1 and 8.2). Thus, no steam is extracted for district water heating. In this mode, the turbine operates as a condensing turbine. Loading rates and limits are determined by the electric-generation capabilities of the turbine-generator and the capabilities of the boiler.

When a unit operates in the cogeneration mode, the electric demand takes precedence over the heating demand. Thus, when the turbine-generator is no longer able to supply an increased demand for electricity and to simultaneously supply the steam demand for DH water heating, the steam to the DH heat exchanger is decreased. In such an event, the water temperature at the outlet of the affected exchanger falls below the desired value, setting off an alarm in the control room. Then the operator can restore the temperature of the DH water by either manually reducing the electric-load demand of the affected unit or by increasing the loads of other units.

It is possible to design the turbine controls so that when a unit operates in the cogeneration mode the heating demand takes precedence over electric demand. But then the turbine control system becomes more complex. Such a system is not justifiable in view of the simple operator actions required when the DH demand cannot be satisfied with an existing equipment configuration.

When a unit operates in the cogeneration mode, the electric generation can be adjusted only within a limited range. This is done either by varying the steam into the low-pressure turbine stage or by varying the steam flow through the main steam-admission valve. These actions change the amount of steam diverted to the low-pressure section or to the entire turbine and, thus, to electric generation. The control zone for the turbine is restricted when it operates in the cogeneration mode, because of the following limitations:

- maximum exhaust flow (through the low-pressure turbine),

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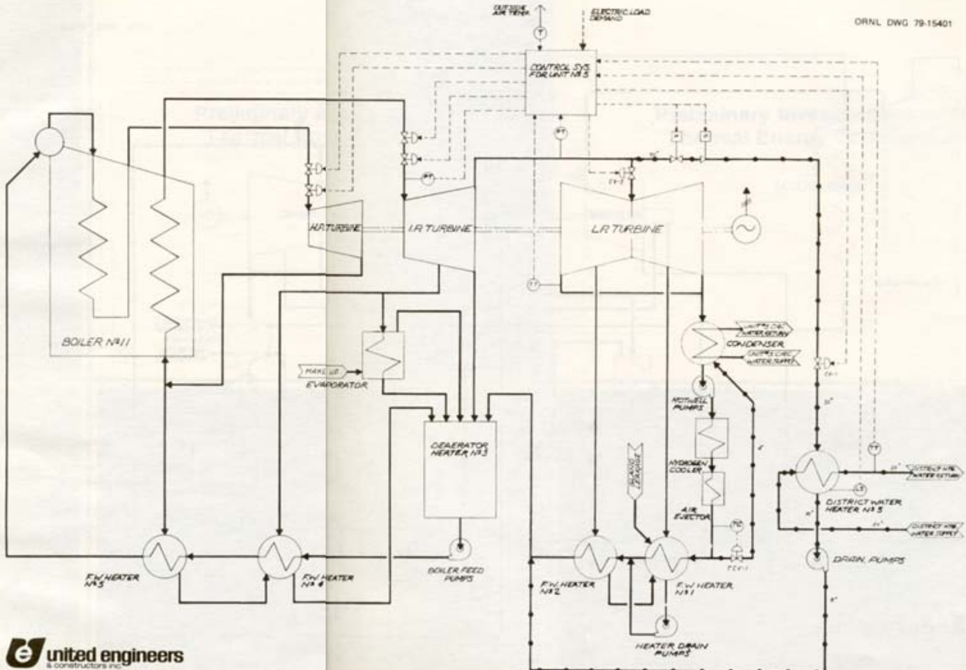

Fig. 8.1. Conversion to district heating of High Bridge unit 5.

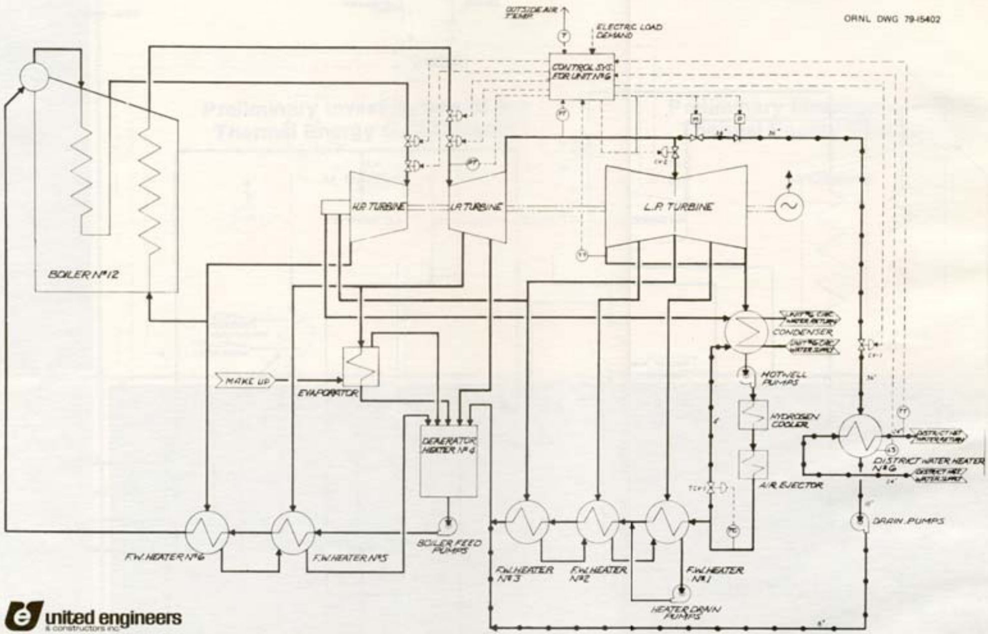

Fig. 8.2. Conversion to district heating of High Bridge unit 6.

- minimum exhaust flow (required for adequate cooling of the low-pressure stages),
- maximum steam flow via the initial stages of the turbine,
- maximum generation capability of the turbine/generator, and
- minimum electric generation.

These limitations establish the permissible control zone, which must be defined by the turbine-generator manufacturer.

The low-pressure turbine exhaust temperature is monitored to ensure that sufficient steam flow is present for adequate cooling. An alarm in the control room informs the operator when this temperature reaches a high limit, thereby indicating that steam flow into the low-pressure turbine section is approaching the minimum acceptable value. The already existing alarms for each unit indicate when electric generation is nearing a limiting value.

8.1.3 Control system for units 5 and 6

The general arrangements of the boiler and the turbine as well as the various steam and water cycles of High Bridge Generating Station units 5 and 6 are almost identical (Figs. 8.1 and 8.2). After conversion, both turbines will operate as cogeneration turbines with condensing tails. The major difference is that unit 6 has one additional feedwater heater at the low-pressure side. Because these units are almost identical, the subsequently outlined control system applies to both High Bridge units 5 and 6.

8.1.4 Turbine control system modifications

This section outlines the control hardware requirements and major modifications to be implemented when converting the existing condensing turbines (High Bridge units 5 and 6) for condensing-tail operation. The following major valves would be installed in the steam piping of the turbine: control valve CV-2 at the inlet to the low-pressure stage of the turbine (Figs. 8.1 and 8.2), and control valve CV-1 and nonreturn and shutoff valves in the extraction-steam piping to the DH heat exchanger (Figs. 8.1 and 8.2). All these valves are controlled by the turbine control system and must be appropriately interfaced with that system.

The electric generation via the high-pressure and intermediate-pressure stages can be significant when the extraction-steam flow to the DH heat exchanger reaches high values. Under this condition, the steam flow to the low-pressure turbine, and consequently, the flow of condensate through the hydrogen cooler, will be low. Thus, the temperature of the condensate at the hydrogen-cooler outlet will rise. A pneumatically operated temperature-control loop is added to maintain the desired temperature. A bypass control valve TCV-1 (Figs. 8.1 and 8.2) automatically opens when this control loop detects a higher condensate temperature at the outlet of the hydrogen cooler. This valve recirculates a part of the condensate to the condenser, and thereby increases the condensate flow through the hydrogen cooler by the proper amount.

8.1.5 Control strategy

The turbine control system is designed to maintain normal operating temperature and pressure conditions within the turbine, regardless of the control mode (cogeneration or electric generation) selected.

When low-pressure steam is extracted for district water heating, the steam flow to the low-pressure stages of the turbine is decreased by an equal amount. Thus, the pressure and temperature conditions within the intermediate-pressure and low-pressure sections of the turbine are not altered when changing the amount of low-pressure steam extracted for district water heating. The temperature and pressure conditions within the intermediate-pressure and low-pressure stages only depend upon the total steam flow through these stages.

The steam flow to the low-pressure section is allowed to decrease only to the minimum required for adequate cooling of the low-pressure stages. The steam flow to the DH heat exchanger is not allowed to increase when the steam flow to the low-pressure section of the turbine reaches the minimum allowable value.

8.1.6 Control system

When a turbine operates in the cogeneration mode, the control valve CV-2 at the inlet to the low-pressure section (Figs. 8.1 and 8.2) maintains the pressure at the intermediate-pressure–low-pressure crossover point at the desired value preventing a high-pressure drop across the intermediate-pressure stage. This pressure should be proportional to the steam flow through the intermediate-pressure turbine and independent of the DH load. The set point for this pressure is established by the pressure transmitter at the inlet to the intermediate-pressure section.

As the heating load increases, the control valve CV-2 in the crossover piping (Figs. 8.1 and 8.2) closes, until it passes only cooling steam to the low-pressure turbine stages. This is the minimum low-pressure-turbine-stage flow condition and corresponds to approximately 15% of the low-pressure-turbine nominal inlet flow. Interlocks prevent further increase of the extraction-steam flow to the DH heat exchanger for as long as the steam flow via the low-pressure stages is at the minimum required value.

The control valve CV-1 in the extraction-steam pipe (Figs. 8.1 and 8.2) controls the water temperature at the outlet of the DH heat exchanger. The outside air temperature determines the set point of the DH water temperature (Fig. 5.2). The control valve CV-1 in the extraction steam pipe (Figs. 8.1 and 8.2) is modulated by the turbine control system as required to maintain the desired water temperature at the outlet of the DH heat exchanger.

8.1.7 Turbine protection

The turbine protective system has priority and is independent of the normal control system. Thus, control signals from the turbine protective system take precedence over the normal control signals. The turbine protective systems consist of the existing protective system and additional protective features, which must be implemented when the units are converted for cogeneration.

One new feature required is to monitor the pressure across the IP-turbine stages. If the pressure differential across the IP turbine stages is too high, a "High Differential Pressure" alarm sounds in the control room. The control valve which admits extraction steam to the DH heat exchanger CV-1 (Figs. 8.1 and 8.2) is repositioned, via interlocks, until proper pressure conditions are restored. Turbine protection is provided by tripping the turbine, if this differential pressure reaches a predetermined high/high value.

A non-return valve, located near the point of extraction, is provided for fast closure to limit turbine overspeed due to entrained energy in the extraction steam. This valve is closed, via interlocks, in the case of turbine trip, high/high level in the DH heat exchanger, or high/high conductivity of the condensate from the DH heat exchanger.

An alarm sounds in the control room when the exhaust-steam temperature at the LP stage reaches an unacceptably high value. In such an event interlocks prevent further opening of control valve CV-1 (Figs. 8.1 and 8.2). The turbine is tripped, after a predetermined time delay, if the high LP-steam exhaust-temperature condition persists. The temperature of the LP exhaust steam is measured by redundant (3 temperature measurements) instrumentation. This redundant arrangement prevents unnecessary turbine trips in case of a single instrument failure. The three redundant temperature measurements are compared with each other and an alarm sounds in the control room when an unacceptable deviation exists. Provisions are made for removing erroneous signals from the measurement circuitry.

8.2 Turbine-Generator Control System for Unit 3

After converting this unit to a backpressure turbine (Fig. 6.1), the steam flow into the turbine is determined by the DH system demand which establishes the amount of heat to be transferred from the LP exhaust steam to the DH water. The basic objective is to balance the steam flow through the turbine with the steam flow required for heating the DH water. The heating requirements are determined by the temperature difference (inlet/outlet) and the flow rate of the DH water. The electric generation is determined by the steam flow through the turbine which in turn depends upon the heat to be transferred to the DH water.

The backpressure turbine is controlled by maintaining the proper pressure at the outlet of the turbine. There is a danger of overloading the 17th stage, if the backpressure drops below 76 kPa (11 psia). This can happen if the DH load is too great. The governing control system of the backpressure turbine operates in the following fashion:

- The speed controller is used for start-up, initial loading of the turbine and for unit shut-down. To prevent overspeeding, the turbine reverts to speed control if the electric generator is tripped.
- After synchronizing, the turbine speed is determined by the grid frequency. The backpressure of the turbine is maintained, over the entire load range, at a constant value. The steam flow into the turbine is controlled, via control valve CV-1 (Fig. 6.1) as required for balancing the heat input into DH heat exchanger 3.

The low-pressure exhaust steam flow from unit 3 is sufficient, up to a certain DH water flow condition, to heat the water to the required intermediate temperature. Part of the DH water is bypassed, around exchanger 3 (Fig. 7.1), when the water flow through the exchanger reaches the limiting flow value. Therefore, during normal operating conditions, there exists no danger of overloading the backpressure turbine.

Before turbine 3 is started, the motor operated valve, at the inlet to DH heat exchanger 3 (Fig. 7.1) is positioned by the operator to restrict the flow of district heating water through exchanger 3. Under this start-up condition, only a reduced exhaust steam flow is required from unit 3 for heating the district water. After start-up, the loading of the turbine-generator is gradually increased by slowly opening the motor-operated valve at the inlet to the DH heat exchanger. This gradually increases the water flowing through exchanger 3, and consequently, the exhaust steam flow required from unit 3.

Significant backpressure variations are inevitable when full water flows, during initial turbine loading, through DH heat exchanger 3. This is because the exhaust steam flow cannot increase in steps.

Turbine protection is provided for abnormal conditions. An alarm sounds if this pressure reaches a predetermined "low" level and a turbine is tripped if the low pressure condition persists for a predetermined time. The turbine is tripped automatically if the back pressure falls below a predetermined low/low level.

The backpressure of the turbine is measured by redundant (3 pressure measurements) instrumentation. This redundant arrangement prevents serious turbine upsets that could result from a single instrument failure. An alarm sounds in the control room when an unacceptable difference exists among the three measurements. Provisions exist for removing erroneous signals from the measurement circuitry.

8.3 The Prevention of Water Damage to Steam Turbines

8.3.1 General

The cogenerating turbines can be severely damaged by water from excessive heat-exchanger condensate level entering the turbine through the extraction point. Features are provided to prevent this water damage. For this purpose, instruments and controls are included in accordance with ASME Standard No. TWDPS-1 "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation, Part 1 — Fossil Fueled Plants."

8.3.2 Control strategy

Two lines of defense prevent water from entering the turbine. Under normal conditions, one control loop regulates the condensate level in the DH heat exchanger. If this control loop cannot prevent the level in the exchanger from reaching the high level, then the first line of defense is actuated. An independent second line of defense is actuated, if the water level in the DH heat exchanger reaches the "HI/HI" level.

8.3.3 Automatic drain system

The normal primary drain line discharges via the drain pumps and control valve CV-3 (Fig. 8.3). An independent control system for control valve CV-5 opens the alternate drain line to the condenser, when the high level is reached.

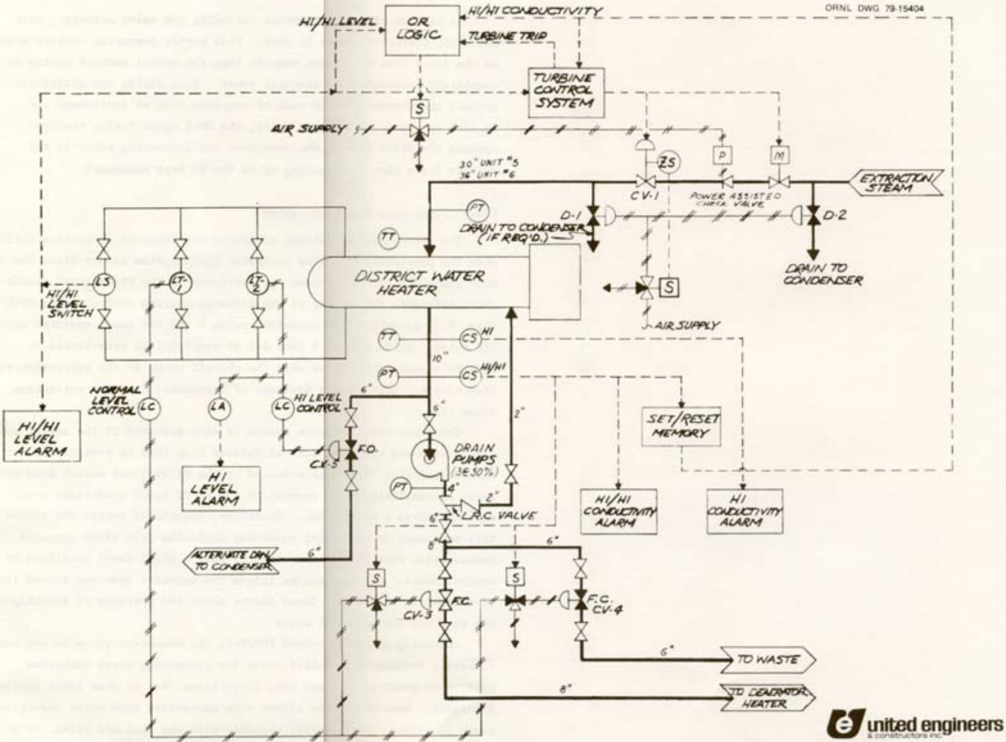

Fig. 8.3. Instruments and controls for the prevention of water damage to the steam turbine of High Bridge units 5 and 6.

In all the control components including the valve actuator, only pneumatic control hardware is used. This purely pneumatic control system as the first line of defense assures that the normal control system is completely independent of electric power. This design can additionally protect the turbine even in case of complete loss of instrument air. In such an event, CV-3 closes fully, and CV-5 opens fully, thereby opening the drain line to the condenser and preventing water in the primary drain line from backing up in the DH heat exchanger.

8.3.4 Steam-side isolation system

The second line of defense initiates the required protective actions, when the previously described automatic drain system cannot drain the DH heat exchanger. These actions are initiated by the HI/HI level switch which initiates the closing of the extraction-steam control valve CV-1 (Fig. 8.3) as well as the nonreturn valve P and the motor operated shut-off valve. Drain valve D-1 (and D-2 if required) is interlocked so that it automatically opens when the shutoff valve in the extraction steam line closes. This assures drainage of condensate from the extraction steam line.

The steam-side isolation system is only actuated if the normal control system and the first line of defense both fail to protect the turbine adequately. Equipment actuated by the HI/HI level switch does not reset automatically after removal of the HI/HI level condition, since this indicates a major upset. Therefore, interlocks permit the return of this equipment to the normal operating condition only after operator intervention from the control console, when a HI/HI level condition no longer exists. Suitable alarms inform the operator when the second line of defense is activated. These alarms alert the operator to investigate and shut off the source of water.

According to ASME Standard TWDPS-1, the nonreturn valve is not considered a satisfactory shutoff valve for preventing water induction because of possible seat and disc distortions, but it does limit turbine overspeed. However, it can afford some protection from water induction since it closes automatically, together with the shut off valve, if a HI/HI level condition develops.

8.3.5 District heating heat exchangers 3 and 3A

District heating heat exchanger 3 transfers the heat from the LP exhaust steam of High Bridge Generating Station unit 3 to the DH water. District heating heat exchanger 3 operates on the same principle as the condenser in the present condensing turbine. Therefore, the previously described measures for preventing water induction are not required for exchanger 3.

District heating heat exchanger 3A is not connected to the steam circuit of a turbine (Fig. 8.3); thus, protective measures to prevent leaks are not required.

The level of the condensate in DH heat exchangers 3 and 3A is controlled by individual pneumatically controlled automatic drain-control valves. Each of these heaters is additionally equipped with HI and HI/HI level switches. A HI-level condition is alarmed to the operator in the control room. HI/HI level in exchanger 3 trips unit 3. HI/HI level in exchanger 3A trips valve PCV-1 (Fig. 6.1).

8.4 Ingression of DH Water

District heating water on the tube side of each DH heat exchanger is at higher pressure than the steam on the shell side. Serious problems can result when DH water leaks from the tube side to the shell side of an exchanger, because the quality of the DH water does not meet the stringent requirements set for boilers and turbines. Therefore, protective actions must immediately be taken.

In the event of a small leak only, a conductivity alarm sounds in the control room. For more serious leaks a bypass valve is installed in the outlet piping of each DH heat exchanger and is controlled by a conductivity cell. Valve CV-3 (Fig. 8.3) closes and bypass valve CV-4 opens when the conductivity cell measures HI/HI conductivity at the outlet of a district water heater. This action prevents the flow of contaminated condensate into the boiler, and bypasses such condensate to waste. Simultaneously with this action a HI/HI conductivity alarm sounds in the control room. Depending on the DH heat exchanger involved, the following additional actions are taken:

1. Exchanger 3: turbine unit 3 is tripped.
2. Exchanger 3A: valve PCV-1 (Fig. 6.1) is tripped.
3. Exchanger 5: the motor-operated shutoff valve and the power-assisted check valve (Fig. 8.1) are closed to prevent the flow of extraction steam into the heat exchanger. Interlocks transfer turbine 5 so that it can only operate in the electric generation mode.
4. Exchanger 6: same as described for exchanger 5.

8.5 District Heating Heat Exchanger 3A

The existing feedwater system from unit 4 can be used (Fig. 6.1) when exchanger 3A is required. Steam from boilers 9 and 10 can supply steam to exchanger 3A. Valve PCV-1 (Fig. 6.1) first reduces the steam pressure from 5900 kPa (850 psi) to approximately 1700 kPa (250 psi). The amount of steam introduced into DH heat exchanger 3A is controlled by control valve TCV-1, as required for maintaining the desired temperature of the DH water.

In the high-pressure and intermediate-pressure heaters the feedwater is heated to the temperature required for proper boiler operation. Steam at 1700 kPa (250 psi) heats the feedwater flowing through the HP heater. Control valve TCV-2 (Fig. 6.1) admits the steam required to maintain the desired temperature of the feedwater.

Control valve PCV-3 maintains the pressure in deaerator heater — unit 4, as required for proper operation of the deaerator. Control valves PCV-1, PCV-2, PCV-3 and TCV-2 (Fig. 6.1) are all controlled by pneumatic instruments mounted directly on the valve actuator as a single field-mounted package to control a single variable. Provisions exist for tripping valve PCV-1 from the control panel. A manual-automatic control station on the control panel for the DH system controls valve TCV-1 (Fig. 6.1). It allows the operator to gradually adjust the steam flow to DH heat exchanger 3A during startup or shutdown.

8.6 Control Panels and Operator Console

8.6.1 General

The turbine sections of the existing control panels must be modified to incorporate additional features required to control the extraction steam to the district water heater. It is assumed that there is no space available in the existing control room for the installation of an additional control panel from which the operation of all DH heat exchangers could be controlled. A separate control panel, provided for this purpose, will be located on the operating floor.

Although not included in the estimate, a digital computer-based information system should be provided. With such a system, the performance of the cogeneration system can be monitored from the control room. In the simplest case only an operator console, with a cathode ray tube (CRT), would be additionally required in the control room providing the operator an interface with the DH water transmission and distribution system, and the turbine-generators used for cogeneration.

The console of a more sophisticated computer-based system would contain, in addition to the CRT, all control switches required for operating the district water system. It would permit operation of the entire DH water system and the cogeneration units from the control room. The data gathering subsystem manipulates the input data to minimize the required operator interactions. A separate control panel for the DH water section is not required with such a computer-based system.

8.6.2 Modification of turbine-generator panels

The panels for units 5 and 6 must be changed to include a crossover pressure indicator, valve position indicators for control valves CV-1 and CV-2 (Figs. 8.1 and 8.2), and open-close control switches for the shutoff valve which is located in the extraction steam line. (The turbine generator operates in the cogeneration mode when this shutoff valve is open and in the electric generation mode when the valve is closed). The panel for unit 3 must be changed to add a backpressure indicator and to remove the interface-to-load dispatch signal and the controls for manually adjusting electric generation. In addition to this, the existing control hardware for all units converted for cogeneration must be modified by the turbine manufacturer, as required to implement the control strategies outlined.

8.6.3 Control panel for DH water system

The DH water system control panel contains all field wiring terminations, interlocks, logic devices, and control stations needed to control all DH heat-exchanger supply and return valves, bypass valves, steam and drain valves, and drain pumps.

Indicators on this panel monitor appropriate pressures, temperatures and flows. Pump status and valve-position indicator lights, as well as recorders, are also included. An annunciator with common alarm outputs to the central control room alarms critical items such as high conductivity of the condensate, and high condensate level. A manual-automatic control station, also on this panel, allows the operator to gradually adjust the steam flow to the heat exchangers during startup or shutdown operations.

9. PLANT OPERATION

9.1 Introduction

The annual heat demand in the DH system varies widely (Fig. 9.1). To satisfy this continually changing heat demand, it will be periodically necessary to change the DH heat exchanger configuration. Tables 9.1 and 9.2 show several DH heat-exchanger configurations and ambient-air temperatures which establish the limit of operation for these various configurations. These tables were developed for the concepts described in Sect. 7.2, Operational Flexibility.

The calculated limiting values (Table 9.1) are based on the assumption that the minimum steam flow to the low-pressure turbine stages of units 5 and 6 is 15% of maximum rated flow to the low-pressure turbine stages. The limiting values (Table 9.2) are based on a 22% steam flow to the low-pressure turbine stages. The calculated limiting values are valid for the heating demand estimated for the year 2000.

At a meeting in Schenectady on October 4, 1978, representatives of the General Electric Corporation indicated that 15% of rated steam flow represents the most likely value of the minimum required low-pressure steam flow, but they declined to establish this value more precisely before doing an engineering analysis. In a letter dated September 7, 1978, a GE representative advised that the minimum required low-pressure steam flow could be as high as 22% of the flow at valves wide-open.

In view of these uncertainties the two tables have been prepared. It should be stressed that 15%, or less, represents the most probable minimum value of the extraction steam flow to the low-pressure turbine stages. EKONO assumed in their study a 15% value for this steam flow.

If the minimum flow is 15%, a single cogeneration unit outage can be tolerated (Table 9.1), even at the lowest design outside air temperature (244 K). If the minimum flow is 22%, no cogeneration unit outage can be tolerated at low outside-air temperature without backup (Table 9.1). But this time period is relatively short. Furthermore, DH heat exchanger 3A which can be supplied by steam from either boiler 9 or 10 can provide the necessary backup if needed, for the relatively

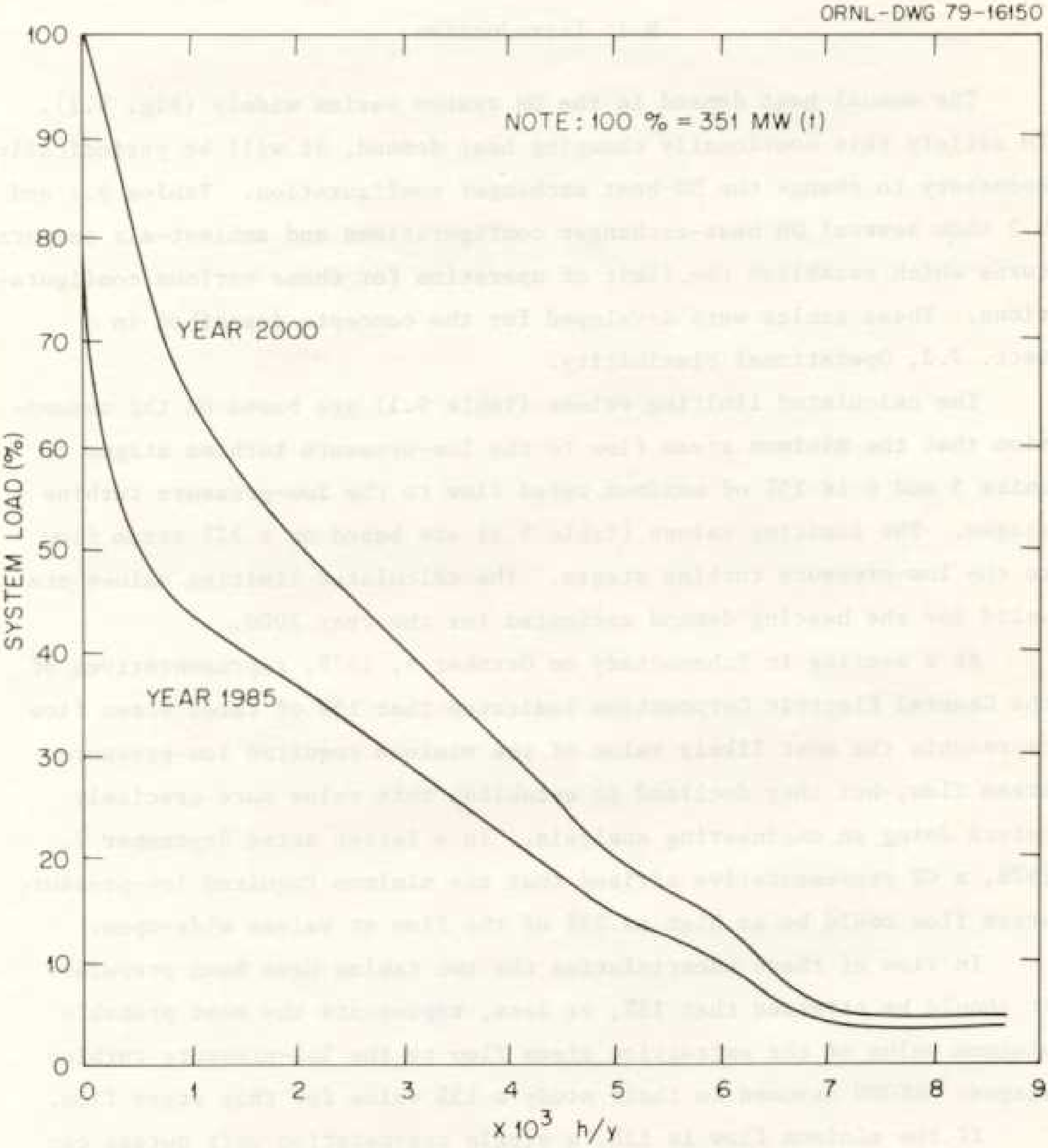

Fig. 9.1. Load duration of St. Paul district heating system for 1985 and 2000.

Source: C.T. Main Co., Boston.

Table 9.1. Ambient air temperatures which establish the operational limits for various district heating heat-exchanger combinations (case I)

Heat exchanger(s) in service	Ambient air temperature limit (K)	Ambient air temperature limit (°F)
3	282.2	48
5	287.7	40
6	265.5	18
3 and 5	261.6	11
3 and 6	251.6	-7
5 and 6	244.4	-20
3, 5, and 6	244.4 (and below)	-20 (and below)

Note: Minimum steam flow to the low-pressure turbine stages of units 5 and 6 is assumed to be 15% of rated flow.

Table 9.2. Ambient air temperatures which establish the operational limits for various district heating heat-exchanger combinations (case II)

Heat exchanger(s) in service	Ambient air temperature limit (K)	Ambient air temperature limit (°F)
3	282.2	48
5	278.9	42
6	268.3	23
3 abd 5	262.8	13
3 and 6	254.4	-2
5 and 6	248.3	-13
3, 5, and 6	244.4 (and below)	-20 (and below)

Note: Minimum steam flow to low-pressure turbine stages of units 5 and 6 is assumed to be 22% of rated flow.

short time of an unusual equipment outage of more than one unit at the maximum load condition. Thus, the selected system combination provides adequate supply reliability and flexibility. The cogeneration units can be used in many different combinations. Different combinations are best for each of the three (low, intermediate, and high) heating demands.

The electric generation of a turbine-generator must also meet certain minimum requirements when operated in the cogeneration mode (Sect. 9.6).

9.2 Low Heating Demand

Low heating demand probably coincides with high electric demand, when the electric generation by the cogeneration units must be at a maximum, while the required steam flow for DH heating is at a minimum. For this condition, unit 3 alone (with units 5 and 6 operating in the electric-generation mode) can be used.

With this equipment combination, steam is not extracted from units 5 and 6 for district water heating; the heat is supplied by unit 3 exclusively. The electric generation by this unit depends on the steam exhausted and thus is maximized for the existing heat demand conditions. Unit 3 operates over the entire load range (from low to high heat demand). Unit 3 will supply the base load when other units are required to meet an increasing heating demand.

This equipment combination can be used when the outdoor air temperature is approximately 282.2 K (48°F) or higher. The corresponding time period is relatively long (late spring through early autumn). It permits scheduled maintenance of the cogeneration units. When unit 3 is out of service for maintenance, either unit 5 or 6 can be changed to cogeneration.

9.3 Intermediate Heating Demand

The intermediate heating demand begins when the outside-air temperature is nearing 282.2 K (48°F). Below this outdoor temperature, unit 3 can no longer satisfy the heating requirements. Either unit 5 or 6 should be changed to cogeneration.

9.4 High Heating Demand

Depending on the cogeneration unit used (either unit 5 or 6), in conjunction with the unit 3 back-pressure turbine, the existing combination can be operated up to a limiting outside-air temperature of 261.6 K (11°F) or 251.6 K (-7°F) (Tables 9.1 and 9.2). At lower temperatures the second condensing-tail cogeneration unit (unit 5 or 6) should be changed to cogeneration.

9.5 Off-Normal Operating Conditions

The heating demand over the entire year can normally be satisfied by using cogeneration units only. Provisions have been incorporated into the system to allow satisfying the heating demand when sufficient cogeneration units are not available for service.

Any of the three cogeneration units can satisfy the heating demand if the outside air temperature is 282.2 K (48°F) or higher (Tables 9.1 and 9.2). As the outside-air temperature falls below this temperature, two cogeneration units will be required. Only at low outside-air temperature are all three cogeneration units required. Thus, the tolerable outage of cogeneration units increases with increasing outside-air temperature. The time period when all three cogeneration units are required is short.

District heating heat-exchanger 3A allows system operation, even if sufficient cogeneration units are not available. All cogeneration units are required only at high heating demands, and only in the unlikely event that the steam flow to the low pressure stages will require 22% minimum flow (Table 9.2). Except for this special condition, other cogeneration units can always provide the necessary backup.

9.6 Electric Generation

The electric generation of unit 3 cannot be adjusted by the operator. The electric generation by this unit is determined by the steam flow via the back-pressure turbine which in turn depends upon the heat to be transferred to the DH water.

When units 5 or 6 operate in the electric generation mode, the electric generation of these units can be adjusted over the entire load range in the same way as before the retrofit. When unit 5 or 6 operates in the cogeneration mode, the electric generation is also adjustable, but only within a limited range. This range is determined by the water temperature desired at the outlet of the DH heat exchanger, and the water flow through the DH heat exchanger.

The saturated-steam temperature in the shell of the DH heat exchanger, the water flow rate and the inlet temperature of the DH water determine the temperature at the outlet. Thus, the saturated-steam temperature must be increased when an increased water temperature is desired. The saturated-steam temperature is determined by the corresponding absolute pressure in the shell of the exchanger. This pressure can only be maintained if the crossover pressure of the cogeneration turbine (unit 5 or 6) is sufficiently high. The crossover pressure increases proportionally with the steam flow through the initial turbine stages. Thus, to obtain a desired crossover pressure, sufficient steam must flow through the initial turbine stages. The electric generation by the initial turbine stages is proportional to the steam flow through these stages. Thus, a certain minimum electric generation is required to obtain a sufficiently high saturated-steam temperature. This minimum required electric generation increases with increasing DH water supply temperature.

When a turbine generator operates with the previously described minimum electric generation and the district water flow through the DH heat exchanger is increased, the extraction-steam flow to that exchanger must also be increased to maintain the water temperature desired at the outlet of the DH heat exchanger. This increased steam flow can only be provided if the steam flow through the initial turbine stages is also increased. This increased steam flow means that the electric generation through the initial turbine stages must also be increased.

The preceding discussions can be summarized as follows:

- When unit 5 or 6 operates in the cogeneration mode, the electric generation must be above a certain minimum value.

- The minimum electric generation requirement increases with increasing DH outlet temperature.
- The minimum electric generation requirement increases proportionately with the water flow through the DH heat exchanger.

Typical values of DH water temperatures and the required minimum electric generation (for cogeneration unit 5) are shown in Table 9.3 for two extreme district water flow conditions (nearly zero district water flow and maximum district water flow).

Table 9.3. Typical minimum required electric generation (MW) when operating High Bridge Unit 5 in the cogeneration mode

District water outlet temperature (K, °F)	Minimum required electric generation (MW) for High Bridge Unit 5	
	Zero flow	Maximum flow
356, 180	10	28
361, 190	11	35
367, 200	14	41
372, 210	18	47
383, 230	27	58

10. PLANT PERFORMANCE

10.1 Load Duration Curve

The estimated system load under the climatic conditions prevailing in the geographic area of the DH system (Fig. 9.1) shows that wide demand variations are to be expected throughout the year.

10.2 Temperature Profile

The supply temperature of the DH water is regulated in the heating power plant as a function of the outdoor air temperature, and varies accordingly (Fig. 7.2). The minimum supply-water temperature of 355.5 K (180°F) is required for producing domestic hot water. To meet increasing system demand, the supply temperature is increased when the ambient temperatures go below 277.7 K (40°F). Return-water temperature (Fig. 7.2) is not controlled, but can be calculated from the predicted load, water flow rate, and supply temperature.

When the ambient temperature is above 294.4 K (70°F), the heat demand is essentially constant. Water flow rate and supply temperature are constant, and accordingly, so will be the return temperature.

As the ambient temperature decreases below 294.4 K (70°F), the space heating load increases and the return temperature will decrease. When the return temperature falls to 322 K (120°F), the water flow rate is gradually increased, while the supply and return temperatures are maintained. This increasing flow rate permits supplying the increasing heat demand. Control of the water flow rate is independent of the supply temperature control and is outside the scope of the UE&C design.

When the outside air temperature decreases to 277.7 K (40°F), the flow rate is a maximum. Below this temperature, the flow rate will be constant, and the increasing heat load will be accommodated by an increasing temperature difference between the supply and return water.

10.3 Heat Balances

The heat balance diagrams for units 3, 5, and 6, after their conversion for cogeneration, are calculated for the limiting main steam flow and extraction-steam flow conditions (Figs. 10.1–10.3). The diagrams indicate, for each unit, the maximum heat load that can be supplied.

The heat balance diagram for unit 3 is calculated for the limiting DH water flow value (point A, Fig. 10.4) when the low-pressure exhaust-steam flow from unit 3 is adequate for heating the DH water to the desired outgoing water temperature. If the district water flow rate is increased, beyond this limiting flow value, the excess DH water must be bypassed around DH heat exchanger 3. The intermediate water temperature [this is the average water temperature resulting after mixing the water which is heated in DH heat exchanger 3 to 355.5 K (180°F) and the bypassed return water] decreases, as the flow rate of the DH water increases, because an increasing amount of the relatively cold return water must be bypassed around the DH heat exchanger (points A–B, Fig. 10.4). When the outdoor air temperature drops below 277.7 K (40°F), the flow rate of the DH water is maintained, but the incoming temperature of the district water increases. Because the higher return temperature of the DH water unit 3 can heat more of the DH water, the bypass flow around exchanger 3 can be reduced accordingly. For this reason the intermediate temperature of the DH water increases (points B–C, Fig. 10.4). Due to temperature limitations in the turbine the DH water temperature is not allowed to go above 361.1 K (190°F).

10.4 Loss of Electric Generation Capacity

As a result of the recommended conversions, electrical generating capacity of each unit will be affected. Unit 3 is currently rated at 62.5 MW(e) with a power factor of one, or 50 MW(e) with a power factor of 0.8, when supplied with 68.04 kg/s (540,000 lb/h) of steam at the turbine inlet. Unit 4 is identical. However, each of the two associated boilers currently has a maximum steam production of only about 56.7 kg/s (450,000 lb/h). Therefore, each unit is only able to generate 42 MW(e) (at a power factor of 0.8).

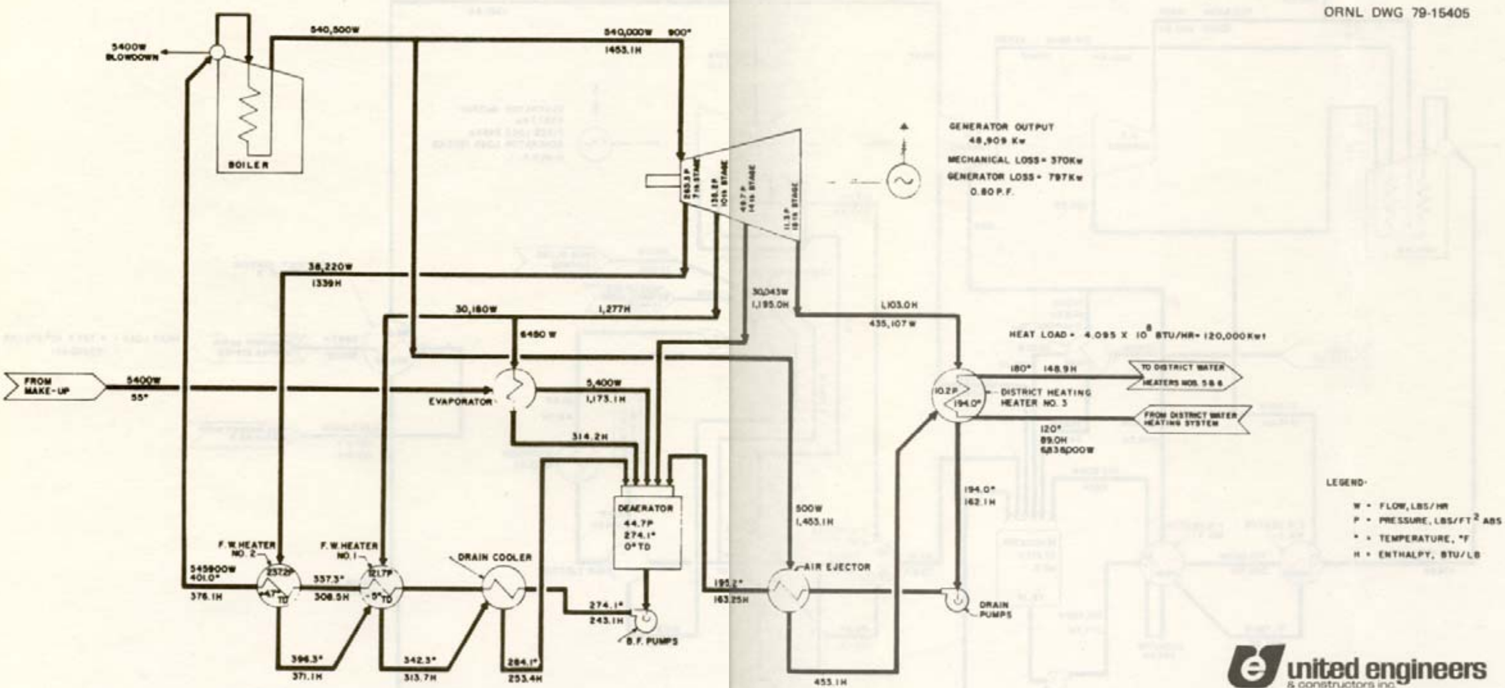

Fig. 10.1. Cogeneration heat balance at maximum main steam flow for High Bridge unit 3.

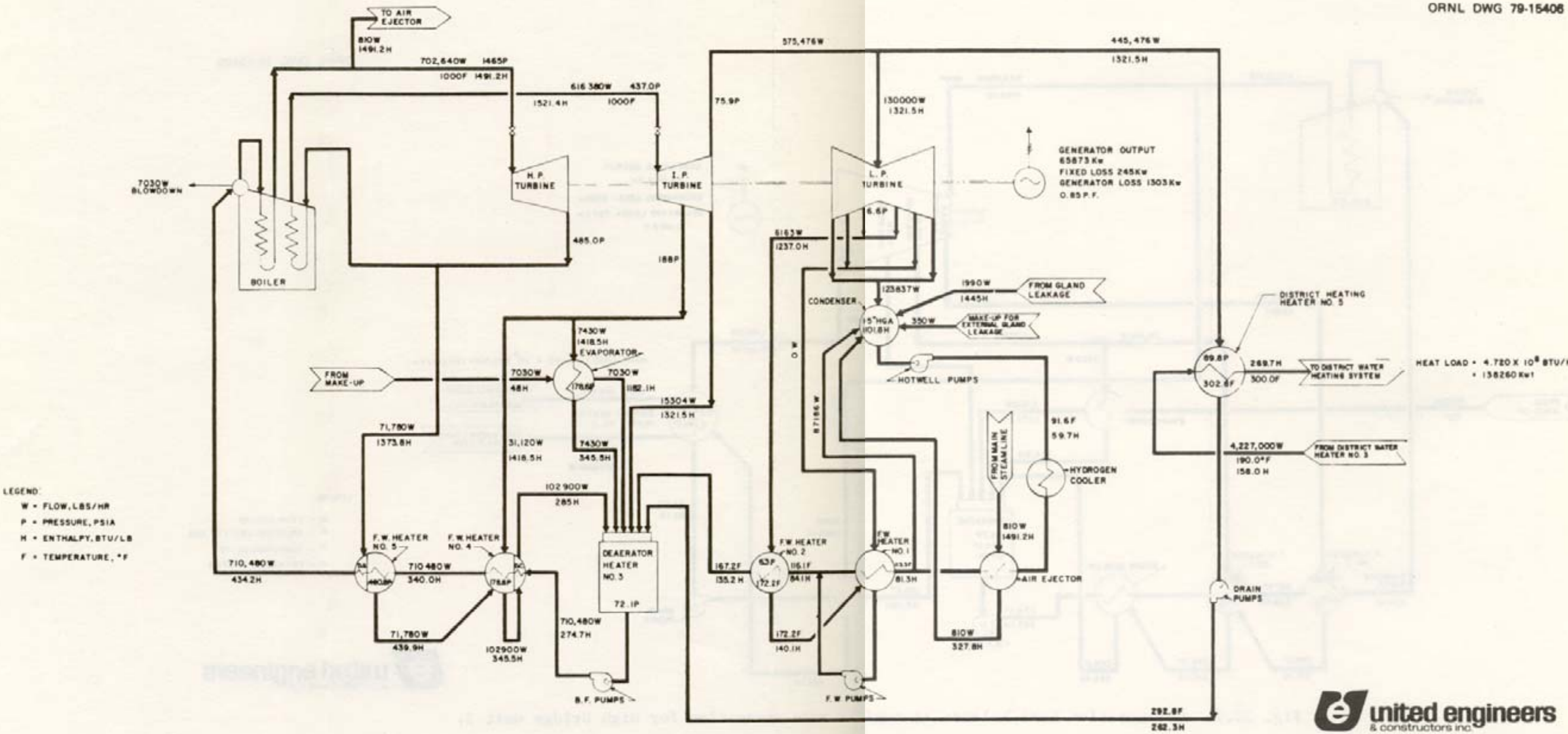

Fig. 10.2 Cogeneration heat balance at maximum main steam flow for High Bridge unit 5.

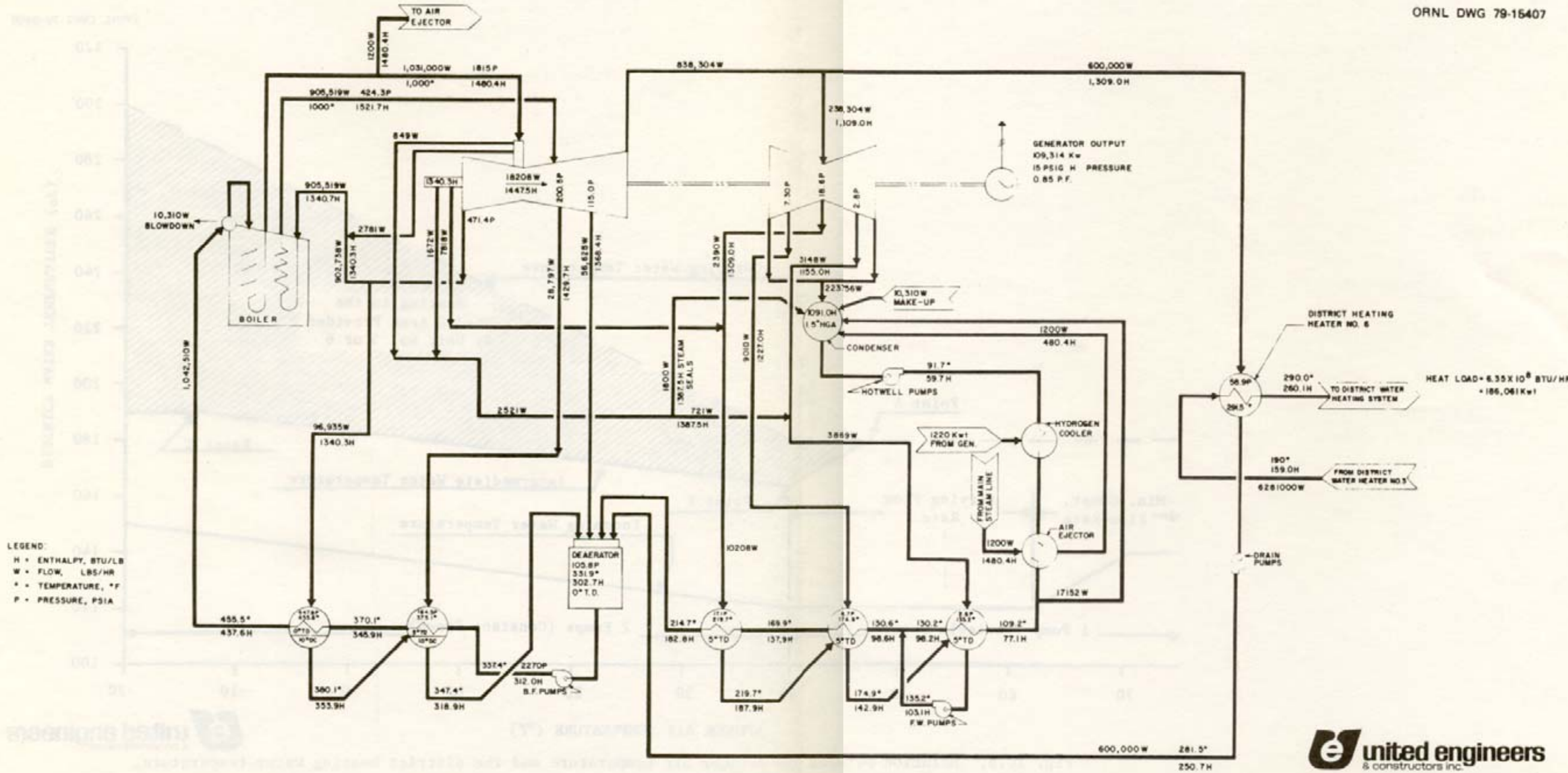

Fig. 10.3. Cogeneration heat balance at maximum main steam flow for High Bridge unit 6.

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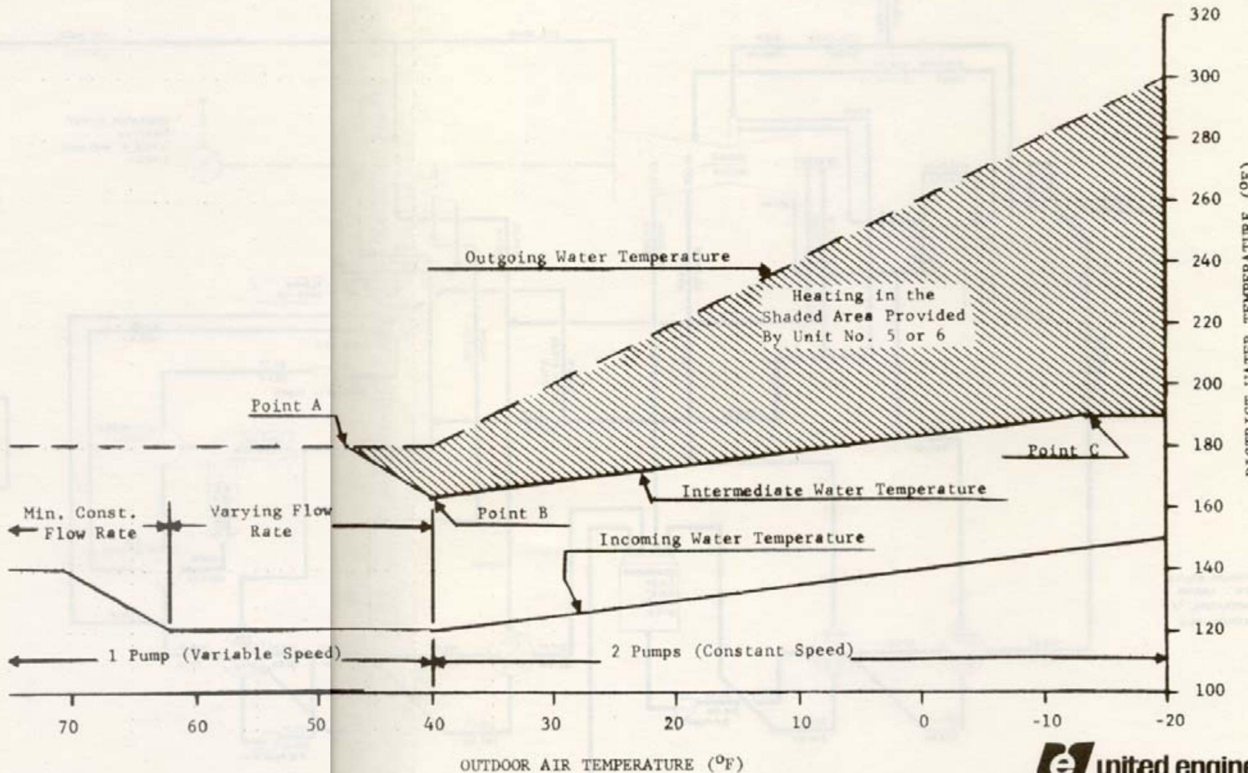

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Fig. 10.4. Relation between the outdoor air temperature and the district heating water temperature.

When both boilers supply steam to the unit 3 turbine, the full 68.04 kg/s (540,000 lb/h) steam flow will be available. With maximum DH load, unit 3 is estimated to generate 49 MW(e) (with a power factor of 0.8), while providing 120 MW(t) to the DH system. Any decrease in DH load will cause a proportional decrease in electrical generation. Unit 3 will provide the base load to minimize the loss of electric generation capacity.

Unit 5 is presently rated at 91 MW(e) (power factor of 0.85). When unit 5 is supplying a maximum DH load of approximately 138 MW(t), the maximum electrical generation capability is estimated to be 65.8 MW(e). When the unit operates in the electric-generation mode, the full 91 MW(e) can be generated.

Unit 6 is presently rated at 156 MW(e). When unit 6 is supplying a maximum DH load of 186 MW(t), the maximum electrical generation capability is estimated to be 109 MW(e). When the unit operates in the electric-generation mode, the full 156 MW(e) can be generated.

The maximum electric generation capacity as well as the maximum DH capabilities of units 5 and 6 are, when operated in the cogeneration mode, affected by the minimum-required steam flow to the low-pressure turbine stages (Sect. 9.1). The estimated values for the maximum electric-generation capacity and for maximum DH capacity are valid under the conditions defined in the heat balance diagrams (Figs. 10.3 and 10.4). The heating load can be increased, above the values indicated on the heat balance diagrams, if the required-minimum steam flow to the low-pressure turbine stages can be reduced below the values indicated. The maximum electric generation must then be decreased proportionately.

The total cogeneration performance of the retrofitted units [444 MW(t)] is simply the sum of the maximum of the individual units (Table 10.1). The capacity of heater 3A will add 100 MW when needed.

Table 10.1. Cogeneration performance of the High Bridge Generating Station

Unit	Original electrical generating capacity (kW)	Original electrical turbine heat rate (MJ/kWh)	Original electrical turbine heat rate (Btu/kWh)	Max. steam extraction (kg/h)	Max. heat energy (x 10^5 MJ/h)	Max. simultaneous elec. generation [kW(e)]	Turbine heat rate at max. extraction (MJ/kWh)	Lost electrical generating capacity [kW(e)]
3	62,265	9.34	9340	957,235	4.095	48,909	3.649	13.356
5	102,182	8.16	8161	980,047	4.72	65,873	5.616	0
6	156,232	7.93	7931	1,320,000	6.35	109,314	5.635	0

11. CONSTRUCTION PLAN

The 1985 DH load will require units 6 and 3 along with exchanger 3A to be in operation at that time. Based on the forecast load growth of 44 MW(t)/y, any two of these three units will be able to satisfy the peak thermal load until 1997, by which time unit 5 must also be retrofitted and in service supplying heat.

The retrofit construction schedule for units 6, 3, and 3A (Fig. 11.1) has been arranged so that unit 6 will be out of service only for the duration of its normally scheduled outage, and it will be back on line in the electric-only mode before any other units must be shut down. To minimize loss of generation capability, no more than one unit will be out of service at any time.

Actual modification of turbine 6 can be scheduled independently of the rest of the retrofit, and in fact, will be scheduled to coincide with a scheduled outage regardless of the balance of plant progress. To complete the turbine retrofit during the scheduled outage, it will be necessary to prefabricate and have onsite all replacement components such as crossover pipes and control assemblies. If the remainder of the plant is not yet ready when the turbine is finished, it can be brought back on line in the electric-only mode with the extraction shutoff valve closed and blanked. Also, the DH heat-exchanger drain-return connections, valved and plugged, to both the deaerator and condenser must also be installed during the outage.

The balance of plant will start with the storage and make-up tank. This will be shop subassembled and match marked. Delivery will be on flatbed trucks through the roll-up doors in the southeast corner of the turbine-hall basement. The sections will be unloaded with the turbine room crane, lifted through the operating floor, traversed northward, and then lowered into the condenser pit. The tank will then be assembled using the circulating-pump pit crane.

Following erection of the tank, pads will be poured for the DH circulating pumps. The pumps can be delivered similar to the tank, then unloaded, and placed by the turbine room crane.

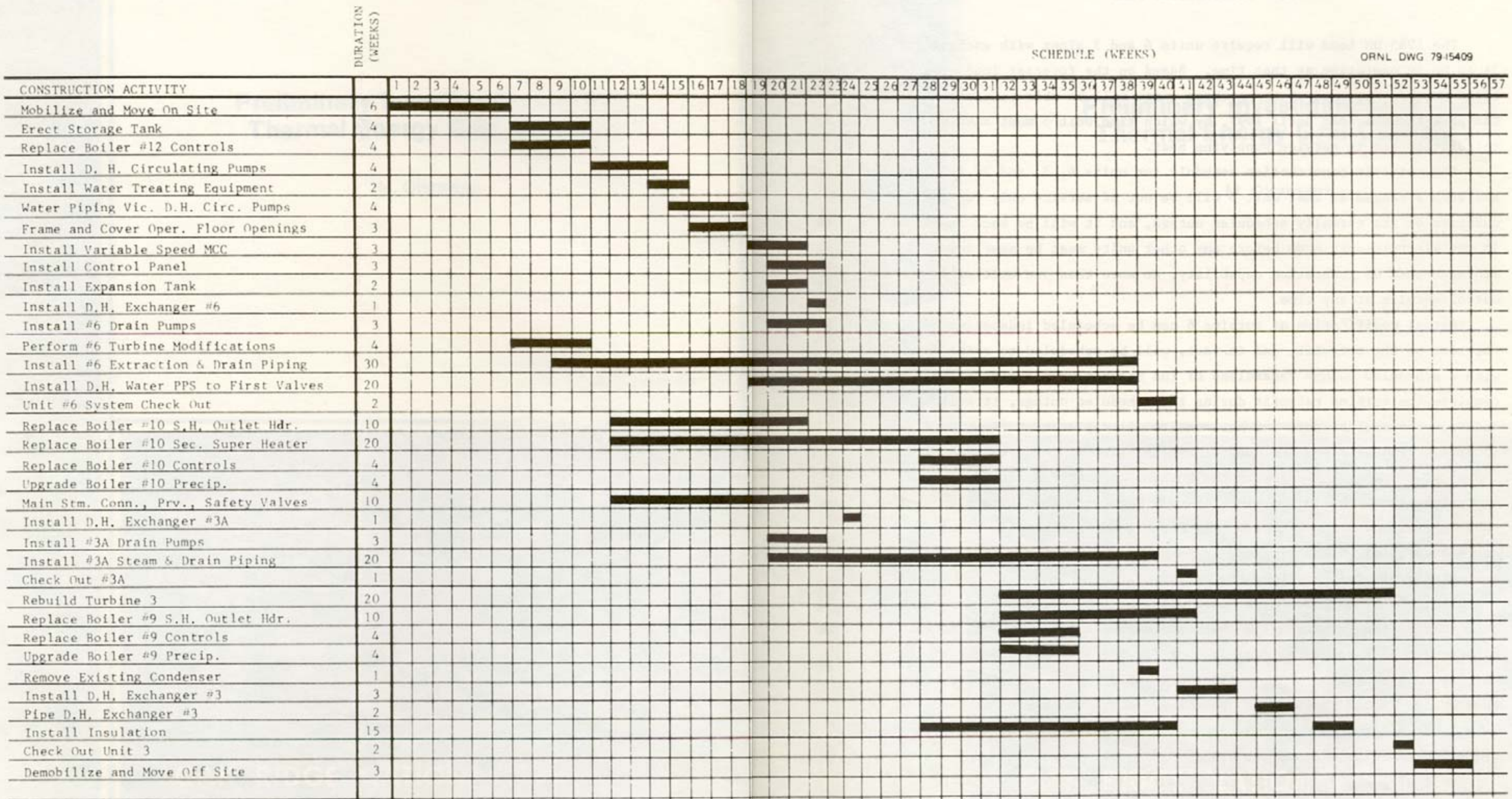

Fig. 11.1. Construction schedule for High Bridge units 3, 3A, and 6.

The water-softening tank and pumps, and the chemical feed equipment will be set in place, and then the DH water piping in the vicinity of the pumps will be installed. With this installation complete, the two operating floor openings along column row E will be framed and covered with grating.

Once these openings are covered, the variable-speed DH pump-motor control center, control panel, and accumulator tank can be placed, piped, and wired. Simultaneously, the piping under the operating floor should be started. This will be mostly DH water piping. District heating heat exchanger 6 and its associated drain pumps, piping, and controls will be installed next using the turbine room crane. The extraction-steam piping, including all valves and supports, should now be completed and closed. If needed, individual pipes can be flushed as soon as they are complete.

After the piping has been cleaned and all wiring and piping completed, the instruments can be calibrated and the system will be ready for check out. Installation of DH heat exchanger 3A and its ancillary equipment will begin as soon as unit 6 has been returned to service and will proceed simultaneously with the balance of the system.

Work on exchanger 3A will begin when boiler 10 is shut down for overhaul. At that time, the required connection to the main steam line will be made and installed up to the three 6R10 safety valves. This permits boiler 10 to be returned to service before the piping to exchanger 3A is complete. The turbine room crane will be used to lift exchanger 3A into place.

Exchanger 3A will be complete one week after unit 6, and 11 weeks before unit 3 is ready. To put unit 6 and exchanger 3A into service supplying heat to the DH system before completion of unit 3, a temporary bypass must be installed around unit 3 and the DH water piping must be finished up to the first shutoff valve in the branches to exchangers 3 and 5.

Work on unit 3 and overhaul of boiler 9 will start as soon as boiler 10 has been returned to service. Unit 3 will be unavailable for approximately 20 weeks.

The entire construction schedule for units 6, 3 and 3A will require one year. This schedule could be compressed by increasing the size of the construction crews and by simultaneous work on (and resulting unavailability of) more than one unit.

Retrofit of unit 5 will be delayed until required by DH system load growth. The procedure for unit 5, will be the same as for unit 6 and the schedule is shown in Fig. 11.2.

A total of 40 weeks will be required to complete unit 5; however, it needs to be out of service for only four weeks. The construction schedule can be shortened by increasing the number of pipe fitters on the job, but too much of an increase will result in a loss of efficiency, and also increase the possibility of inadvertant interference with other station operations.

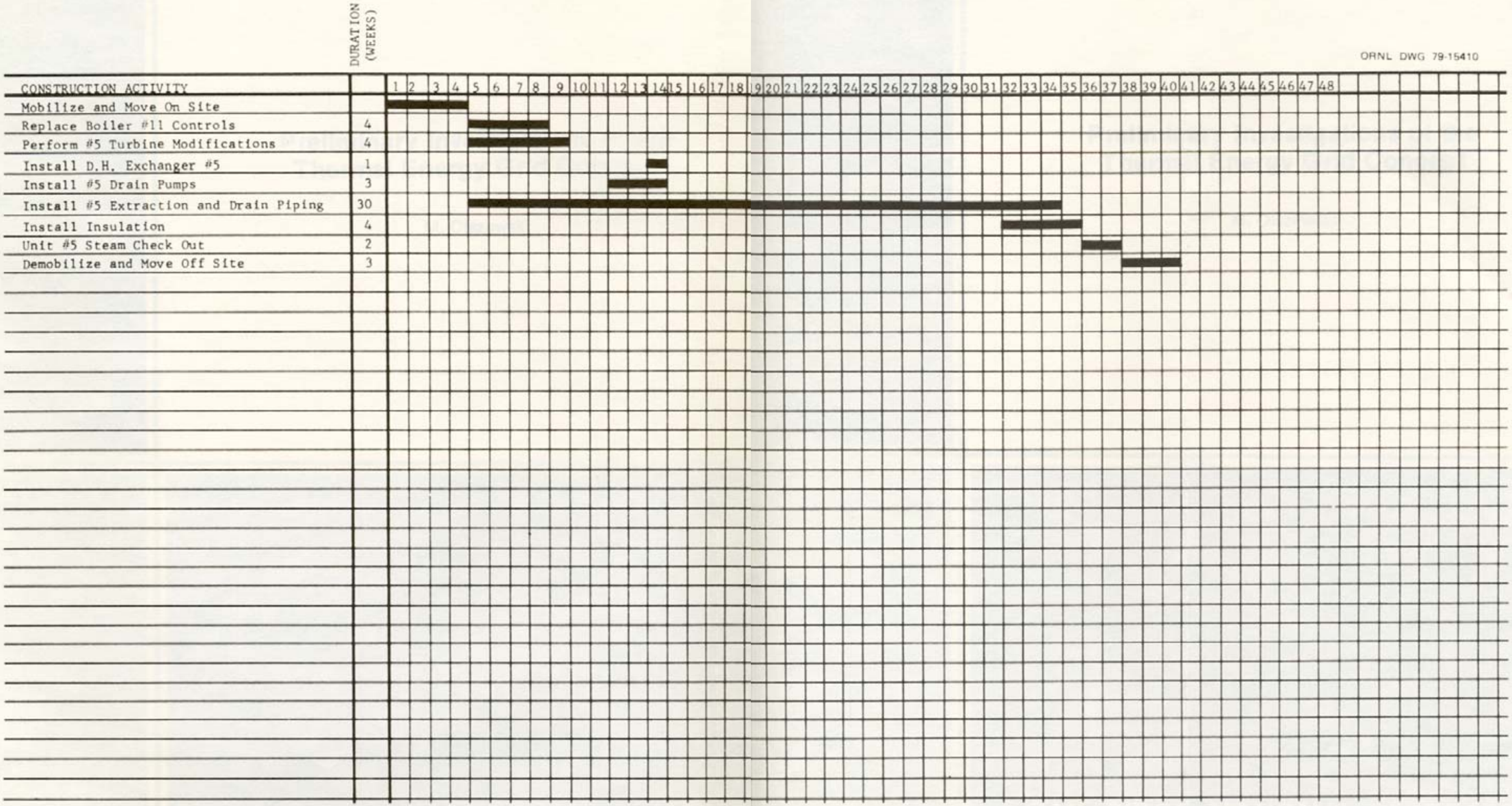

Fig. 11.2. Construction schedule for High Bridge unit 5.

12. EQUIPMENT LIST

The major items of equipment required to retrofit the High Bridge Generating Station include items needed for the retrofit, as well as those items required for maintenance or repair of existing equipment which will be retained (Tables 12.1-12.11).

Four boilers will be improved. Boilers 9 (unit 3) and 10 (unit 4) will have new boiler controls and a new superheater outlet header. Also boiler 10 will need a new secondary superheater. Boilers 11 (unit 5) and 12 (unit 6) will need new controls.

Precipitators for boilers 9 and 10 require parts for upgrading.

District heating heat exchanger 3 will be either a conventional small condenser with four tube passes or a standard shell-and-tube heat exchanger with a special nozzle to adapt to the existing turbine exhaust connection. This DH heat exchanger will be arranged for horizontal mounting in place of the existing unit 3 condenser. Construction will be carbon steel shell-and-tube sheets with 20-BWG type 304 stainless steel straight tubes [2.54 cm (1 in.)]. Waterside design pressure is 2515 kPa (350 psig). Steamside design pressure is flooded to full vacuum.

The condensing zone is designed to heat 2,047.5 kg/s (16,250,000 lb/h) of water from 339 to 361 K (150 to 190°F) with 44.36 kg/s (352,100 lb/h) of steam at 76 kPa (11 psia) and 365.4 K (197.8°F). The total capacity is 97 MW(t) from approximately 2,787 m^2 (30,000 ft^2) of effective heat transfer surface.

District heating heat exchanger 5 will be a shell-and-tube heat exchanger with two tube passes arranged for horizontal mounting. Construction will be of carbon steel shell-and-tube sheets with 20-BWG type 304 stainless steel U-tubes [1.91 cm (3/4 in.)]. Waterside design pressure is 2515 kPa (350 psig). Steamside design pressure is 1136 kPa (150 psig). The desuperheating and condensing zones have approximately 1486.40 m^2 (16,000 ft^2) of effective heat-transfer surface to heat 504 kg/s (4,000,000 lb/h) of water from 361.1 K (190°F) to 419.4 K (295°F), condensing 50.29 kg/s (399,100 lb/h) of steam at 496 kPa (72 psia), 578.7 K (581.6°F). Total capacity is 123 MW(t).

Table 12.1. High-pressure steam piping (including hangers)

Size			Weight		Length	Total weight		Fitt weight	
cm	in.	Schd	kg/m	lb/ft	(lin ft)	kg	lb	kg	lb
				Chrome-moly steel (A-335 Gr. P-12)					
60.9	24	0.375 in. wall	141	94.6	30	1287	2838	680	1500
50.8	20	0.375 in. wall	117	78.6	50	1782	3930	227	500
45.72	18	0.375 in. wall	105	70.6	240	7686	16,945	1134	2500
30.48	12	60	74	49.6	25	270	595		
25.4	10	40	60	40.5	150	2755	6075	454	1000
15.24	6	40	28	19	100	862	1900	136	300
10.16	4	40	22	14.6	125	828	1825	123	275
5.08	2	40				272	600	45	100
				Carbon steel (A-106 Gr. B)					
35.56	14	20	68	45.7	400	8292	18,280	1225	2700
25.4	10	20	42	28.0	100	1270	2800	318	700

Table 12.2. High-pressure steam valves[a]

Size		Class	Operation	Body
cm	in.			
		Gate valves[b]		
30.48	12	900	Motor	A-217-WC9
25.4	10	300	Manual	A-217-WC9
10.16	4	150	Manual	A-217-WC9
		Globe valves[c]		
10.16	4	150	Pneumatic	-C5
10.16	4	150	Pneumatic	-C5
15.24	6	300	Pneumatic	-C5
30.48 × 50.80	12 × 20	900	Pneumatic	-C9
40.64 × 60.96	10 × 24	300	Pneumatic	-C9

[a]One of each needed.

[b]Trim of 410 stainless steel.

[c]Trim of hardened stainless steel.

Table 12.3. High-pressure safety-relief valves[a]

Size	Set (psig)	kPa	Quantity
6R10	275	2000	3
6R10	125	963	1
6Q8	50	446	1

[a]All with a tungsten steel spring and an A217-WC6 body.

Table 12.4. Low-pressure extraction piping[a]

Size			Weight			Total weight		Fitt weight	
cm	in.	Schedule	kg/m	lb/ft	Length (lin ft)	kg	lb	kg	lb
60.9	24	0.375 in. wall	140.76	94.6	25	1072.76	2365	226.80	500
76.2	30	0.375 in. wall	177.07	119	340	18352.66	40,460	3311.28	7300
60.9	24	0.375 in. wall	140.76	94.6	25	1072.76	2365	226.80	500
91.44	36	0.375 in. wall	212.04	142.5	460	29733.48	65,550	4536	10,000
5.08	2	40				362.88	800	90.72	200

[a]Carbon steel (A-106 Gr. B).

Table 12.5. Low-pressure extraction valves[a]

Size				
cm	in.	Class	Operation	Quantity
		Check valves (extraction non-return)		
76	30	150	Pneumatic	1
91	36	150	Pneumatic	1
		Globe valves[b]		
5	2	150	Pneumatic	4
		Butterfly valves[b]		
76	30	150	Motor	1
91	36	150	Motor	1
76	30	150	Pneumatic	1
76	36	150	Pneumatic	1

[a]All class 150 with carbon steel body.
[b]With stainless steel trim.

Table 12.6. Heat exchanger vent and drain piping (including hangers)[a]

Size		Weight		Length (lin ft)	Total weight		Fitt weight	
cm	in.	kg/m	lb/ft		kg	lb	kg	lb
25	10	60	40.5	120	2204	4860	363	800
20	8	43	28.6	1600	20756	45,760	2721	6000
15	6	28	19.0	1125	9695	21,375	1451	3200
10	4	16	10.8	260	294	648	136	300
5	2				1088	2400	272	600

[a]All schedule 40.

Table 12.7. Heat-exchanger vent and drain piping

Size		Class	Operation	Quantity
cm	in.			
		Gate valves[a]		
5	2	150	Manual	6
5	2	300	Manual	3
10	4	150	Manual	6
10	4	300	Manual	3
		Globe valve[a]		
10	4	150	Pneumatic	1
		Butterfly valves[b]		
15	6	150	Manual	18
15	6	300	Manual	1
20	8	150	Manual	4
20	8	300	Manual	2

[a]With carbon steel body and stainless steel trim.

[b]With carbon-steel body, 316/disc, stainless steel trim, fiberglass-reinforced Teflon seat, 17-4 precipitation-hardened shaft, and a Teflon shaft seal.

Table 12.8. Special valves[a] for heat exchanger vent and drain piping

Type	Size		Operation	Body	Quantity
	cm	in.			
Sliding gate[b]	8	3	Self-contained	CS	2
ECC disc[c]	10	4	Pneumatic	SS	2
ECC disc[b]	15	6	Pneumatic	CS	3
ECC disc[c]	15	6	Pneumatic	SS	2
Yarway LARC[b]	10 × 5	4 × 2	None	CS	9

[a]All class 150.

[b]Stainless steel trim.

[c]Hardened stainless steel trim.

Table 12.9. District heating water piping (including fittings and hangers)

Size		Wall thickness	Weight		Length	Total weight		Fitt weight	
cm	in.	(in.)	kg/m	lb/ft	(lin ft)	kg	lb	kg	lb
76.2	30	0.500	235	158	475	34043	75,050	5443	12,000
60.9	24	0.500	186	125	64	3629	8,000	1814	4,000
50.8	20	0.375	117	78.6	40	1426	3,144	544	1,200
45.7	18	0.375	105	70.6	75	2402	5,295	453	1,000
40.64	16	0.375	93	62.6	75	2129	4,695		

Table 12.10. Butterfly valves for DH water piping[a]

Size				
cm	in.	Class	Operation	Quantity
76.2	30	300	Motor	2
76.2	30	300	Manual	4
60.9	24	300	Motor	2
60.9	24	300	Manual	2
50.80	20	300	Motor	1
50.80	20	300	Manual	2

[a]All have lug style carbon steel bodies, 316 stainless steel discs, graphite-impregnated, fiberglass-reinforced Teflon seats, and Teflon shaft seals.

Table 12.11. Low-voltage power cable needed for High Bridge retrofit[a]

Size (AWG)	Lin ft
2/0	600
4	1000
8	3900
12	1500

[a]Triplexed, copper with EPA insulation and Hypalon jacket.

District heating heat exchanger 6 will be a shell-and-tube heat exchanger with two tube passes arranged for horizontal mounting. Construction will be of carbon steel shell and tube sheets with 20-BWG type 304 stainless steel U-tubes [1.91 cm (3/4 in.)]. Waterside design pressure is 2515 kPa (350 psig). Steamside design pressure is 1140 kPa (150 psig). The desuperheating and condensing zones have approximately 1,858 m^2 (20,000 ft^2) of effective heat-transfer surface to heat 535.5 kg/s (4,250,000 lb/h) of water from 361 to 417 K (190 to 290°F), condensing 51.27 kg/s (406,400 lb/h) of steam at 435 kPa (63 psia), 563.2 K (553.8°F). Total capacity is 125 MW(t).

District heating heat exchanger 3A will be a shell-and-tube heat exchanger with two tube passes arranged for horizontal mounting. Construction will be of carbon steel shell and tube sheets with 20-BWG type 304 stainless steel U-tubes [2.54 cm (1 in.)]. Waterside design pressure is 2515 kPa (350 psig). Steamside design pressure is 2170 kPa (300 psig). The desuperheating, condensing, and drain cooling zones have approximately 1115 m^2 (12,000 ft^2) of effective heat-transfer surface to heat 1,039.5 kg/s (8,250,000 lb/h) of water from 355.5 K to 395 K (180 to 251°F), condensing 59.85 kg/s (475,000 lb/h) of steam at 700 K (800°F) and approximately 689 kPa (100 psia). Total capacity is 72 MW(t).

Drain pumps for DH heat exchanger 5 will be three nominally half-size pumps designed for 3.47 m^3/s (550 gpm) at 45.72 m (150-ft) TDH with suction conditions of 482 kPa (70 psia), 422.2 K (300°F). These pumps will be centerline mounted with end suction, top discharge, and radially split case. The casings, shafts, and impellers are made of stainless steel (11-13% chromium). The pumps will be approximately 75% efficient at design and will require 30-hp motors.

Drain pumps for DH heat exchanger 6 will be three nominally half-size pumps designed for 0.05 m^3/s (725 gpm) at 45.72-m (300-ft) TDH with 414 kPa (60 psia) suction pressure and 414 K (285°F) fluid temperature. These pumps will be centerline mounted with end suction, top discharge, and radially split case. The casings, shafts, and impellers will be made of stainless steel (11-13% chromium). The pumps will be approximately 75% efficient at design and will require 100-hp motors.

Drain pumps for DH heat exchanger 3A will be three nominally half-size pumps designed for 0.04 m^3/s (600 gpm) at 21.3-m (70-ft) TDH with 483 kPa (70 psia) suction pressure and 394 K (250°F) fluid temperature. These pumps will be centerline mounted with end suction, top discharge and radially split case. Parts in contact with liquid will be made of stainless steel (11-13% chromium). Pumps will be approximately 72% efficient at design and will require a 20-hp motor.

Special items for high-pressure steam piping include one lot of traps, nozzles, and orifices, and one lot of hangers and supports (90% spring cans, 10% rods and brackets). Insulation will be calcium silicate [10.16 cm (4-in.) thick] applied in two layers with staggered joints and covered with an aluminum jacket [255.48 m^2 (2750 ft^2)].

Special items for low-pressure extraction piping will include two flanged expansion joints with laminated type 304 stainless steel multi-arch bellows [76.2 cm (30 in.) and 91.4 cm (36 in.)]; one lot of traps, nozzles and orifices; and one lot of hangers and supports (30% spring cans, 60% rods and brackets, and 10% "A" frames). Insulation will be calcium silicate [7.16 cm (3-in.) thick] applied in two layers with staggered seams [700 m^2 (7550 ft^2)] and covered with an aluminum jacket.

Special items for heat-exchanger vent and drain piping include eighteen flanged expansion joints with laminated type 304 stainless steel multi-arch bellows [nine 15.24 cm (6-in.), and nine 10.16 cm (4-in.)]. One lot of traps, nozzles, and orifices are needed and one lot of hangers and supports (30% spring cans, 70% rods and brackets). Insulation will be calcium silicate with aluminum jacket: A 2.54-cm-layer (1-in.) will insulate pipes up to and including 10.16 cm (4 in.); this will total 46.45 m^2 (500 ft^2). A 3.8-cm-layer (1-1/2-in.) will insulate pipes 15.24 to 30.48 cm (6 to 12 in.); this will total 538.82 m^2 (5800 ft^2). Control equipment will include four flow elements and one control panel (2.4 × 2.1 × .9 ft). Three kinds of instrument transmitters will be needed: temperature (14), pressure (16), and flow (4).

One lot of hangers and supports (40% spring cans, 60% rods and brackets) will be required for the DH water piping. Insulation will be 5.08-cm-thick (2-in.) calcium silicate with an aluminum jacket (5200 ft^2).

Turbine 3 will require a back-pressure controller package, a new speed governor, a new 17th-stage bucket and diaphragm set, a low-pressure-turbine spool piece, and a new seal steam regulator.

Turbine 5 will require new intermediate-pressure-low-pressure crossover pipes, two crossover control valves, and some additional controls.

Turbine 6 will require new intermediate-pressure-low-pressure control valves, and some additional controls.

The distribution panelboard (dc) will be provided with 24-V dc power supply for the annunciator.

There will be one motor control center (480 V) of NEMA Class-I construction with type-B wiring, drawout type, 600-A horizontal bus, 300-A vertical bus, and braced for 42,000 A (symetrical). This motor control center includes nine full-voltage, non-reversing, single-speed circuit-breaker motor starters (three each of NEMA sizes 2, 3, and 4); eight NEMA size-1 full-voltage, reversing, single-speed circuit-breaker motor starters; twenty-one NEMA size-1 full-voltage, non-reversing, circuit-breaker contactors; five 100-A molded-case 25,000-A I.C. circuit breakers; and one 15-kVA single-phase dry-type distribution transformer. Also needed is a distribution panel with 24 single-pole 20-A, E-frame molded-case air circuit breakers. The panel is arranged for 120/240-V, 3-wire, single-phase service.

Steel conduit of 1-1/2 nominal size will be required (11,500 ft). Also needed will be low-voltage power cable (Table 12.10), control wire (5000 lin ft of 5 conductor #12 Awg), and instrument wire (7700 lin ft of twisted shielded pair). Annunciators will be placed at 24 locations.

Miscellaneous instrumentation and controls needed will include six local indicators, seven board-mounted indicators, twelve process switches, eleven controllers, and five recorders.

Equipment insulation for DH heat exchanger 3 will be calcium silicate [5.08-cm-thick (2-in.)] with an aluminum jacket [approximately 65.03 m^2 (700 ft^2)]. Insulation for DH heat exchangers 5, 6, and 3A will be calcium silicate [10.16-cm-thick (4-in.)] with an aluminum jacket, applied in two layers with staggered joints [approximately 214 m^2 (2300 ft^2)]. Drain pumps and miscellaneous equipment will be insulated with approximately 56 m^2 (600 ft^2) of [5.08-cm-thick (2-in.)] foam.

13. COST ESTIMATES

13.1 Capital Cost Estimate

This detailed estimate of the investment required to retrofit the High Bridge Generating Station for cogeneration is based on 1978 equipment prices and labor rates. No allowance has been included for escalation to the estimated 1984-1985 starting date. This estimate does not include NSP management and administrative costs, nor interest during construction. The estimated cost for engineering assumes that the retrofit concept is as described in this report.

Northern States Power Company operating personnel have estimated that new controls for boilers 9 and 10 will cost approximately $800,000 installed. The NSP control system estimate includes changing from the existing pneumatic controls to electronic controls and additional control capabilities. This estimate which includes only $250,000 for controls is based on a straight replacement of the existing equipment with new equipment for which repair parts will continue to be available into the future.

Included in the estimate are costs incurred as a result of the conversion, and also costs resulting from repairs or maintenance required to extend the life of units 3, 5, and 6 (Table 13.1). A detailed cost accounting is included on the next eight pages (ORNL DWG 79-15411 through 79-15418).

Table 13.1. Capital costs summary

Name	Conversion	Maintenance
Structures and improvements	$ 30,000	
Boiler plant equipment	4,105,000	$2,450,000
Turbine-generator units	2,880,000	
Accessory electric equip.	315,000	
Total direct cost	$7,330,000	$2,450,000
Total indirect cost[a]	620,000	200,000
	$7,950,000	$2,650,000
Contingency (15% of total)	1,050,000	350,000
Total	$9,000,000	$3,000,000

[a]Indirect costs include construction services, and engineering and field office personnel.

PRICED BY ______ **DETAIL ESTIMATE**

APPROVED BY ______ Northern States Power Company

DATE 2/16/79 JOB High Bridge Station - Cogeneration Study

ORNL DWG 79-15411

SHEET NO 1

J.O. NO 6742.001

				LABOR				MATERIAL		SUB CONTRACT			
ACCT. NO	DESCRIPTION	QUANTITY	UNIT	M-HRS/UNIT	MAN HRS	RATE	AMOUNT	RATE	AMOUNT	MAN HRS	S-C RATE	AMOUNT	TOTALS
	This estimate is intended to cover the						$		$			$	$
	design and construction cost of												
	converting the existing High Bridge												
	Generating Station to Cogeneration.												
XXPH...	POWER HOUSE												
10	LAND AND LAND RIGHTS												Existing
11	STRUCTURES AND IMPROVEMENTS												
	Structural Work												
11C110	Structural steel	6	T	30.	180	22.	4,000	850.	5,100				
11D310	Floor grating	2,500	SF	.2	500	22.	11,000	3.	7,500				
11Y000	Painting, etc.	1	LOT		70	20.	1,400		1,000				
	Total Structures and												
	Improvements, -						16,400		13,600				30,000
12	BOILER PLANT EQUIPMENT												
12A100	Steam Generators												
12A101	Boiler No. 9												
	Replace superheater outlet header											100,000	
	Replace controls											125,000	
12A102	Boiler No. 10												
	Replace superheater outlet header											100,000	
	Replace controls											125,000	
	Replace secondary superheater											850,000	
12A103	Boiler No. 11 - Replace controls											500,000	
12A104	Boiler No. 12 - Replace controls											500,000	
	Total Steam Generators, -											2,300,000	

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DATE 2/16/79 JOB High Bridge Station - Cogeneration Study

DETAIL ESTIMATE

Northern States Power Company

ORNL DWG 79-15412

SHEET NO 2

J.O. NO 6742.001

ACCT NO	DESCRIPTION	QUANTITY	UNIT	LABOR M HRS / UNIT	LABOR MAN HRS	LABOR RATE	LABOR AMOUNT	MATERIAL RATE	MATERIAL AMOUNT	SUB CONTRACT MAN HRS	SUB CONTRACT S-C RATE	SUB CONTRACT AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
12	BOILER PLANT EQUIPMENT (Cont'd)												
12D400	Precipitators												
12D401	Upgrade precipitator - Boiler No. 9											75,000	
12D402	Upgrade precipitator - Boiler No. 10											75,000	
												150,000	
12N100	District Heating Heat Exchangers												
12N101	District Heating Exchanger No. 3												
	30,800 sq. ft. horizontal shell												
	and tube heat exchanger	1	EA		520	22.	11,400		400,000				
12N102	No. 5 (18,000 sq. ft.)	1	EA		300	22.	6,600		235,000				
12N103	No. 6 (20,700 sq. ft.)	1	EA		350	22.	7,700		270,000				
12N104	No. 3A (14,000 sq. ft.)	1	EA		240	22.	5,300		184,000				
12N105	Existing Condenser No. 3												
	Disconnect, remove and scrap (cost												
	offset by sale of scrap metal)												
12N106	Insulation - Calcium Silicate												
	With Aluminum Jacket												
	Exchanger No. 3 (2" thick)	1,600	SF									16,600	
	Exchanger No. 5 (4" thick)	800	SF									12,800	
	Exchanger No. 6 (4" thick)	900	SF									14,400	
	Exchanger No. 3A (4" thick)	700	SF									11,200	
	Foundations												
12N107	Reinforced concrete	5	CY	20.00	100	20.	2,000	100.	500				
12N108	Steel saddles	5,400	LB	.03	160	22.	3,500	.65	3,500				
12N109	Painting, etc.	1	LOT		20	20.	400		100				
	Total District Heating												
	Heat Exchangers, -						36,900		1,093,100			55,000	

DETAIL ESTIMATE

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DATE 2/16/79 JOB Northern States Power Company
High Bridge Station - Cogeneration Study

ORNL DWG 79-15413

SHEET NO 3
J.O. NO. 6742.001

				LABOR				MATERIAL		SUB CONTRACT			
ACCT NO	DESCRIPTION	QUANTITY	UNIT	M HRS / UNIT	MAN HRS	RATE	AMOUNT	RATE	AMOUNT	MAN HRS	S-C RATE	AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
12	BOILER PLANT EQUIPMENT (Cont'd)												
12N200	Heat Exchanger Drain Pumps												
12N201	Drain Pumps - Exchanger No. 5												
	550 gpm, 150' tdh pumps	3		60.	180	22.	4,000		12,700				
	30 hp, 480 volt, 3,550 rpm motors	3		20.	60	22.	1,300		1,200				
12N202	Drain Pumps - Exchanger No. 6												
	725 gpm, 300' tdh pumps	3		90.	270	22.	5,900		15,400				
	100 hp, 480 volt, 3,550 rpm motors	3		30.	90	22.	2,000		3,800				
12N203	Drain Pumps - Exchanger No. 3A												
	600 gpm, 70' tdh pumps	3		60.	180	22.	4,000		18,500				
	20 hp, 480 volt, 1,750 rpm motors	3		20.	60	22.	1,300		900				
12N204	2" Foam Insulation on Pumps	600	SF									4,500	
12N205	Foundations												
	Reinforced concrete	5	CY	20.	100	20.	2,000	100.	500				
	Clean-up, etc.	1	LOT				4,000		1,500				
	Total Heat Exchanger Drain Pumps, -						24,500		54,500			4,500	
	Boiler Plant Piping												
12S011	High Pressure Steam Piping												
	Chrome-moly piping	42,000	LBS	.3	12,600	22.	277,200	3.50	147,000				
	Carbon steel piping	26,000	LBS	.2	5,200	22.	114,400	1.50	39,000				
	Gate valves	3	EA						19,000				
	Globe valves	5	EA						180,000				
	Safety relief valves	5	EA						15,000				
	Hangers and supports	14,000	LBS						28,000				
	Traps, nozzles, orifices, etc.	1	LOT				1,500		4,000				
							393,100		432,000				

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DETAIL ESTIMATE

Northern States Power Company
High Bridge Station - Cogeneration Study

ORNL DWG 79-15414

SHEET NO 4
J.O. NO 6742.001

				LABOR				MATERIAL		SUB CONTRACT			
ACCT NO	DESCRIPTION	QUANTITY	UNIT	M HRS / UNIT	MAN HRS	RATE	AMOUNT	RATE	AMOUNT	MAN HRS	S-C RATE	AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
12	BOILER PLANT EQUIPMENT (Cont'd)												
	Boiler Plant Piping (Cont'd)												
12S012	High Pressure Steam - Insulation												
	4" Calcium silicate insulation												
	with aluminum jacket	3,000	SF									48,000	
12S031	Low Pressure Extraction Piping												
	Carbon steel piping	130,000	LBS	.2	26,000	22.	572,000	1.50	195,000				
	Check valves	2	EA						77,000				
	Globe valves	4	EA						6,000				
	Butterfly valves	4	EA						67,000				
	Hangers and supports	25,000	LBS						50,000				
	30" and 36" stainless steel												
	bellows type expansion joints	2	EA	50.	100	22.	2,200		12,000				
	Trays, nozzles, orifices, etc.	1	LOT				1,000		2,500				
							575,200		409,500				
12S032	Low Pressure Extraction -												
	Insulation												
	3" Calcium silicate insulation												
	with aluminum jacket	7,600	SF									100,000	
12S033	Low Pressure Extraction -												
	Foundations	Allowance					1,900		5,200				
12S121	Heat Exchanger Vent and												
	Drain Piping												
	Carbon steel piping	95,000	LBS	.2	19,000	22.	418,000	1.50	142,500				
	Gate valves	18	EA						6,000				
	Globe valves	1	EA						4,000				
	Butterfly valves	25	EA						12,000				
	Special valves	18	EA						43,000				
	Hangers and supports	19,000	LBS						38,000				

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APPROVED BY ____________
DATE 2/16/79 JOB ____________

DETAIL ESTIMATE

Northern States Power Company
High Bridge Station - Cogeneration Study

ORNL DWG 79-15415

SHEET NO ____________
J.O. NO 6742.001

				LABOR				MATERIAL		SUB CONTRACT			
ACCT NO	DESCRIPTION	QUANTITY	UNIT	M HRS / UNIT	MAN HRS	RATE	AMOUNT	RATE	AMOUNT	MAN HRS	S-C RATE	AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
12	BOILER PLANT EQUIPMENT (Cont'd)												
	Boiler Plant Piping (Cont'd)												
12S121	Heat Exchanger Vent and												
	Drain Piping (Cont'd)												
	4" and 6" stainless steel,												
	bellows type expansion joints	18	EA	10.	180	22.	4,000		4,500				
	Traps, orifices, nozzles, etc.	1	LOT				2,500		2,500				
							424,500		252,500				
12S122	Vent and Drain Pipe Insulation												
	1" Calcium silicate with												
	aluminum jacket	500	SF									4,500	
	1½" Calcium silicate with												
	aluminum jacket	5,800	SF									58,000	
												62,500	
	Total Boiler Plant Piping, -						1,394,700		1,099,300			210,500	
	Instrumentation and Control												
12V160	Primary flow elements	4	EA						24,000				
12V180	Control panel (8' x 7' x 3')	1	EA						16,000				
12V260	Pressure switches	11	EA						10,700				
12V261	Controllers	11	EA						11,600				
12V262	Local and board indicators	13	EA						3,000				
12V263	Recorders	5	EA						6,200				
12V264	Annunciator power supply, 24V d-c	1							3,000				
12V290	Transmitters	34	EA						21,200				
12V300	Field erection labor						28,400		3,000				
							28,400		98,700				
12Y000	Painting - Boiler Plant						1,200		3,800				
	Total Boiler Plant Equipment, -						1,485,700		2,349,300			2,720,000	6,555,000

DETAIL ESTIMATE

PRICED BY ____________

APPROVED BY ____________ Northern States Power Company

DATE 2/16/79 JOB High Bridge Station - Cogeneration Study

ORNL DWG 79-15416

SHEET NO. [illegible]

J.O. NO. 6742.001

ACCT NO	DESCRIPTION	QUANTITY	UNIT	LABOR: M HRS / UNIT	LABOR: MAN HRS	LABOR: RATE	LABOR: AMOUNT	MATERIAL: RATE	MATERIAL: AMOUNT	SUB CONTRACT: MAN HRS	SUB CONTRACT: S-C RATE	SUB CONTRACT: AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
14	TURBINE-GENERATOR UNITS												
14A231	District Heating Water Piping												
	Carbon steel piping	120,000	LBS	.2	24,000	22.	528,000	1.50	180,000				
	Butterfly valves	13	EA						75,000				
	Hangers and supports	24,000	LBS						48,000				
	Traps, nozzles, orifices, etc.	1	LOT				2,000		2,000				
							530,000		305,000				
14A232	Heating Water - Insulation												
	2" Calcium silicate Insulation with aluminum jacket	5,200	SF									57,000	
14J101	Turbine No. 6												
	Rework crossover piping between IP and LP turbines including controls for new 36" extraction main				1,200	25.	30,000		675,000				
14J102	Turbine No. 5												
	Add control valves on two crossover pipes and new 30" extraction main				2,000	25.	50,000		600,000				
14J103	Turbine No. 3												
	Backpressure controller package								90,000				
	New speed governor								30,000				
	17th Stage bucket diaphragm								60,000				
	Spool piece								150,000				
	Seal steam regulator								32,000				
	Boresonic inspection								13,000				
	Installation				8,000	25.	200,000		50,000				
							200,000		425,000				
14Y000	Painting - Turbine Plant	Allowance					6,000		2,000				
	Total Turbine-Generator Units -						816,000		2,007,000			57,000	2,880,000

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DATE 2/16/79 JOB High Bridge Station - Cogeneration Study

DETAIL ESTIMATE

Northern States Power Company

ORNL DWG 79-15417

SHEET NO. ____

J.O. NO. 6742.001

ACCT NO	DESCRIPTION	QUANTITY	UNIT	LABOR M HRS/UNIT	LABOR MAN HRS	LABOR RATE	LABOR AMOUNT	MATERIAL RATE	MATERIAL AMOUNT	SUB CONTRACT MAN HRS	SUB CONTRACT S-C RATE	SUB CONTRACT AMOUNT	TOTALS
XXPH...	POWER HOUSE (Cont'd)						$		$			$	$
15	ACCESSORY ELECTRIC EQUIPMENT												
15c500	Motor Control Center												
	Motor starters	17	EA						20,700				
	Contactors	21	EA						19,300				
	Circuit breakers	5	EA						1,900				
	15 KVA transformer	1	EA						1,200				
	24-circuit panelboard	1	EA						700				
	Relay section	1	LOT						1,000				
	Space heaters	10	EA						1,000				
	Gasketed doors	10	EA						700				
	Installation				450	22.	9,900		600				
							9,900		47,100				
15L200	Conduit												
	Rigid galvanized steel	11,500	LF	.7	8,050	22.	177,100	1.50	17,300				
15L410	600 Volt Wiring	7,000	LF	.09	630	22.	13,900	1.40	9,800				
15L500	Control Cable	5,000	LF	.1	500	22.	11,000	1.00	5,000				
15L700	Instrument Cable	7,700	LF	.1	770	22.	16,900	.90	7,000				
	Total Accessory Electric Equipment, -						228,800		86,200				315,000
	Total Power House, -						2,546,900		4,456,100			2,777,000	9,780,000

PRICED BY ______

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DATE 2/16/79 JOB High Bridge Station - Cogeneration Study

DETAIL ESTIMATE

Northern States Power Company

SHEET NO. ______

J.O. NO. 6742,001

ORNL DWG 79-15418

				LABOR				MATERIAL		SUB CONTRACT			
ACCT NO	DESCRIPTION	QUANTITY	UNIT	M HRS / UNIT	MAN HRS	RATE	AMOUNT	RATE	AMOUNT	MAN HRS	S-C RATE	AMOUNT	TOTALS
97D010	TEMPORARY OFFICE AND OPERATIONS						$		$			$	$
	Job office trailer with utilities including office supplies, bank charges, telephone, etc.												20,000
98A000	FIELD OFFICE PERSONNEL												
	UE&C Field Superintendent and his staff												300,000
99A500	HOME OFFICE ENGINEERING AND SERVICES												
	Engineers, Designers, Construction Managers and Their Assistants Including Start-up personnel working out of UE&C Inc. Home Office												500,000
	CONTINGENCY												1,400,000
	ESCALATION												Not Included
	Total Estimate, -												$ 12,000,000
	ITEMS NOT INCLUDED												
	Spare Parts												
	State Taxes												
	Preliminary Operations												
	Northern States Power Company - Expenses												
	Fire Insurance During Construction												
	Interest on Funds During Construction												
	Premium Wages - Estimate is based on 5-Day, 40-Hour Week at Prevailing Rates.												

13.2 Operating Costs

13.2.1 General

To determine the cost of producing heat and electricity at the converted High Bridge Generating Station, UE&C has prepared a report titled "Allocation Method for the Separation of Electrical and Thermal Costs — High Bridge Generating Plant Cogeneration Retrofit Study November 1978." United Engineers & Constructors Inc. has recommended the method of cost allocation described by P. Margen of A. B. Studsvik of Sweden for the retrofit study of the High Bridge Station.

The basic assumption is that the systemwide cost of electricity will not be significantly affected by the modifications to the High Bridge Generating Station, as the High Bridge plant represents a small portion of total system capacity. The Margen method also assumes that the cost of electricity produced at the High Bridge plant is defined from its historic use, and this value can be substracted from the overall cost of operating the cogeneration station. The remaining costs (including amortization of the retrofit costs) represent the cost of producing thermal energy.

13.2.2 Total Annual Costs

With a fixed annual heat demand, the total annual cost of the converted High Bridge Generating Station will be a function of the electrical capacity factor (CF) (Table 13.2).

The electrical output which corresponds to a 100% CF is defined as the total annual generation by units 3, 5, and 6 when the steam flow to unit-3 turbine is as required by the heat load and the steam flow to units 5 and 6 remains constant at their corrresponding rated value [unit 5, 88.53 kg/s (702,640 lb/h); unit 6, 129.91 kg/s (1,031,000 lb/h)].

Any steam not extracted from units 5 and 6 for DH purposes is passed through the respective LP turbines to produce electricity by condensation only. This gives the maximum potential annual electrical generation of the converted units, while simultaneously supplying the annual heat load.

Table 13.2. Total anual cost as a function of electrical capacity factor[a]

Electric power capacity factor (%)	Electric energy (10^9 kWh/yr)	Annual costs ($\$10^6$/yr) Fuel	Operation and maintenance	Total[b]
100	2.460	21.37	6.68	34.45
90	2.214	19.37	6.41	32.18
80	1.968	17.35	6.14	29.89
70	1.722	15.33	5.87	27.61
60	1.476	13.32	5.60	25.32
50	1.230	11.30	5.34	23.04

[a]With heat production fixed at 2.59×10^6 GJ/yr (2.45×10^{12} Btu/yr).

[b]Each case includes fixed costs of $\$6.4 \times 10^6$ per year.

Annual generation which corresponds to the other CF values (90, 80, 70, 60, and 50%) is determined by multiplying the generation at CF = 100% by the appropriate CF value.

13.2.3 Cost of Electricity

In accordance with the recommended method of cost allocation, the electric unit cost equals the electric unit cost resulting from separate generation (Table 13.3).

13.2.4 Cost of Heat

The cost of the thermal energy is determined by subtracting the electrical costs from the total annual costs (Table 13.3).

These unit costs are production costs at the High Bridge Generating Station, and do not include amortization costs of the distribution system, or other distribution costs such as pumping power.

Table 13.3. Relation of unit costs to electric power capacity factor

Electric power capacity factor (%)	Electrical unit cost (mills/kWh)	Thermal unit cost [\$/GJ (\$/10^6 Btu)]	
		Operating	Total[a]
100	12.97	0.44 (0.46)	0.99 (1.04)
90	13.39	0.44 (0.46)	0.99 (1.04)
80	13.90	0.44 (0.46)	0.99 (1.04)
70	14.56	0.44 (0.46)	0.99 (1.04)
60	15.44	0.43 (0.45)	0.98 (1.03)
50	16.68	0.43 (0.45)	0.98 (1.03)

[a]Includes fixed costs of \$0.55 per GJ (\$0.58 per 10^6 Btu).

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